# International support for onshore wind

A REPORT PREPARED FOR DECC

June 2013

# International support for onshore wind



Contents

# International support for onshore wind

# Executive Summary

Support for renewable generation is an important part of the UK Government's energy policy. The mechanisms and levels of support need to be carefully designed so that they are deployed in a cost-effective manner, minimising costs to consumers while ensuring the renewables industry develops effectively and targets are met.

Frontier Economics was commissioned by DECC to undertake an evidence review of onshore wind electricity generation, focusing on international evidence of government initiatives to support such investment and deployment.

- In part one of this project we compared the level and nature of onshore wind support regimes in 26 countries and regions around the world[1].

- In part two we further analysed the reasons for differences in support levels using five international case studies (Denmark, Germany, Netherlands, Ireland and Poland).

The main conclusions from our analysis are as follows.

- **Support for onshore wind in the UK in 2011 was in the top half of 26 countries and regions examined**. In general support levels were lowest in North America while Denmark and Sweden saw the lowest support levels in Europe. Depending on the measure of comparison (see Section 3) the UK has between the 7th and 9th highest support level. This was when support for onshore wind was provided at 1 ROC/MWh. The UK remains in the top half of countries examined when a reduction in support to 0.9 ROCs in 2013 is taken into account[2].

- **Differences in estimated costs and load factors explain a large amount of the differences in support levels across countries**. The countries studied showed that those with higher estimated costs and lower load factors for wind generation tend to have higher support levels, inclusive of market revenues.

- **The UK has relatively high estimated costs for onshore wind and this largely explains the above average support levels compared to other case studies**. Central estimates of levelised costs in the UK were around

1 The criterion for this choice was countries that had at least 1000 MW of installed onshore wind capacity by the end of 2011.

2 In this report we consider the support level at 1 ROC as this was the support level in 2011, the latest year for which consistent data was available across and countries and regions considered.

£100/MWh for new projects in 2011, which is in line with the support provided in the UK (including market revenues). Although there are substantial uncertainties around the data, three reasons appear to explain these relatively high levelised costs in the UK (in order of importance):

- **Higher capital costs**. Estimated capital costs in the UK are around £0.3 - 0.4m/MW higher than those in other case study countries (with the exception of Ireland where costs are similar).
- **Higher financing costs.** The central weighted-average cost of capital (WACC) of 9.6% (pre-tax, real) assumed in the UK is higher than those quoted in other countries, which are typically around 6% to 8% (with the exception of Poland).
- **Higher operating costs.** Compared to other case study countries, estimated operating costs are at least £5,000 - 10,000/MW/year higher in the UK (with the exception of Poland). This is largely explainable by higher transmission charges facing generators in the UK.

While the higher operating costs in the UK can be largely explained by higher transmission charges, the reasons behind the higher capital and financing costs in the UK are less clear. For capital costs, higher construction costs are the most likely driver of this difference[3].

Reasons cited for higher financing costs in the UK include the nature of the support scheme (in particular whether or not generators face price risks), government financing support in other countries[4] and development risk.

To test whether these (or other) factors can explain the entirety of the differences in levelised cost estimates, a detailed 'bottom-up' engineering study would be needed alongside contract/transactional data[5] from actual projects for comparable windfarms across different countries. However, we note there are inherent difficulties obtaining this information given commercial confidentiality.

---

3 Connection cost may have a small influence. Meanwhile, the central turbine cost estimates we have used suggest slightly higher turbine costs in the UK but this may not be material given the uncertainties around the estimates. Anecdotal discussions with industry experts suggest that turbine prices in the UK are in line with those in continental Europe.

4 In Germany a large proportion of wind farms receive financing from KfW, a state-guaranteed bank, at below market rates.

5 For example, construction, turbine and debt contracts.

## Measures of support used in this report

In comparing the levels of support internationally we use a number of different measures. First we measure support on both an '**absolute**' (including market revenues) and '**net**' basis (excluding market revenues). Within these measures we make the following distinctions.

- **Average support levels** (£/MWh). This is the average level of support provided to all onshore plant in operation in 2011 under the main support scheme. This captures the fact that in some countries the plant in operation will be receiving different levels of support (e.g. according to capacity, location or year of installation).

- **Initial support levels for new plant** (£/MWh). This is the support provided to new plant commissioning in 2011 in its first year of operation. There is often a range of support levels for new plant.

- **Levelised support levels for new plant** (£/MWh). For the detailed case studies we calculate a discounted average measure of support levels for projects commissioning in 2011 over the course of the project (20 years). This takes into account the duration of support and grandfathering arrangements (i.e. whether support is grandfathered in real or nominal terms).

For the measures above we also provide comparisons on both a market exchange rate and purchasing-power-parity (PPP) basis. The Methodology section provides a fuller explanation of these metrics.

## COMPARING INTERNATIONAL SUPPORT LEVELS

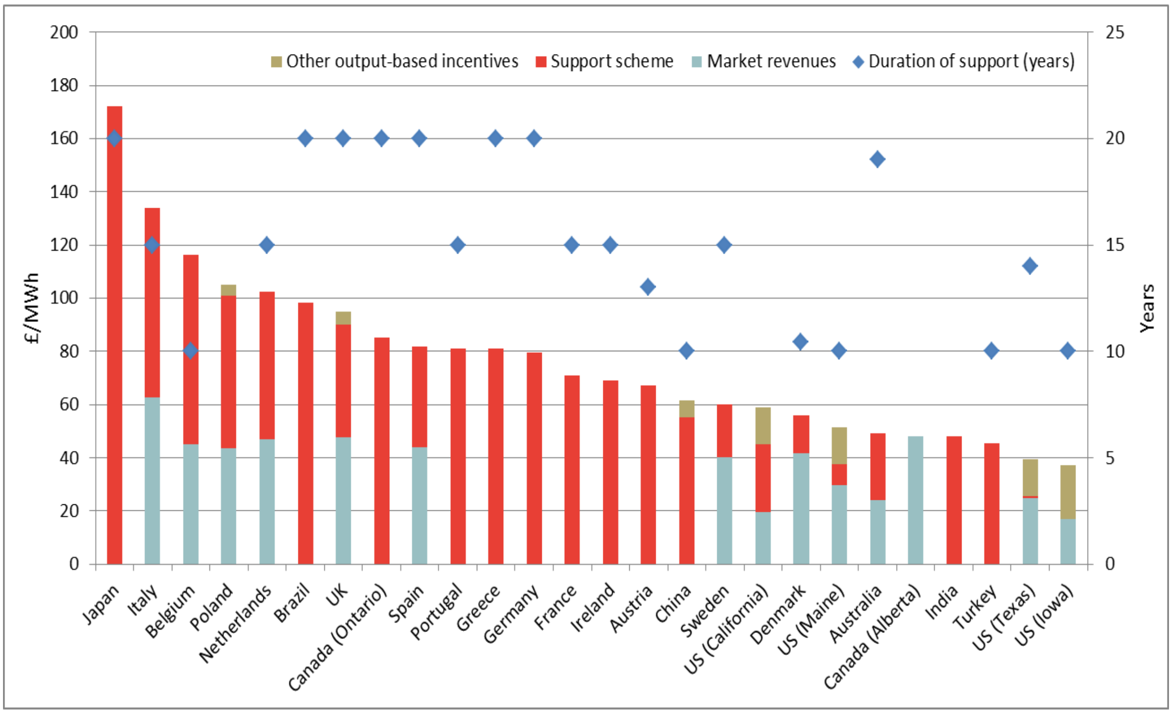
We find a range of incentive mechanisms in use for onshore wind support across the 26 countries and regions we study. These include output-based subsidies (Quota, Feed-in Tariff and Premium Feed-in Tariff schemes), production tax incentives, investment tax incentives, priority grid connection and loan guarantees.

Figure 1 provides an example of the analysis undertaken in Section 3 and shows average absolute support levels compared on a market exchange rate basis in 2011. The 'absolute' support level is the total level of support including market revenues, the value of the main support scheme and other support linked to generation output (e.g. production tax incentives).

The average support for onshore wind in the UK in 2011 in absolute terms was around £95/MWh including the value of the wholesale revenues, the receipt of one Renewables Obligation Certificate (ROC) per MWh of generation and one

CCL exemption certificate (LEC)[6]. This support level is in the top half of 26 countries and regions examined.

**Figure 1.** Comparison of average absolute support levels (market exchange rates, £/MWh)




Source: Data from various sources, analysis by Frontier Economics

To account for potential distortions in market exchanges rates we also completed comparisons on a purchasing-power-parity (PPP) basis (see Section 3). On this basis UK support levels remained in the top half of countries and regions studied. We also compared the net support, which is the support provided in addition to the market value of generation, including a measure which adjusts for the duration of support (see Section 3). Similar results emerged.

On all measures, the UK support levels rank as between the 7th and 9th highest out of the 26 countries and regions considered. The relative position of the UK is summarised in Table 1 below. In general, the lowest support levels are seen in the US, Canada and Australia, with Denmark and Sweden seeing the lowest support levels within Europe.

---

6 This value of the wholesale revenues is taken from the average APX baseload spot price (£48/MWh). For consistency with other estimates we do not adjust for the wind market value in this case but we do in the detailed case studies. The value of the ROC in 2011/12 was £42/MWh (according to the Renewables Annual report 2011/12 from Ofgem. The value of the LEC is £5/MWh.

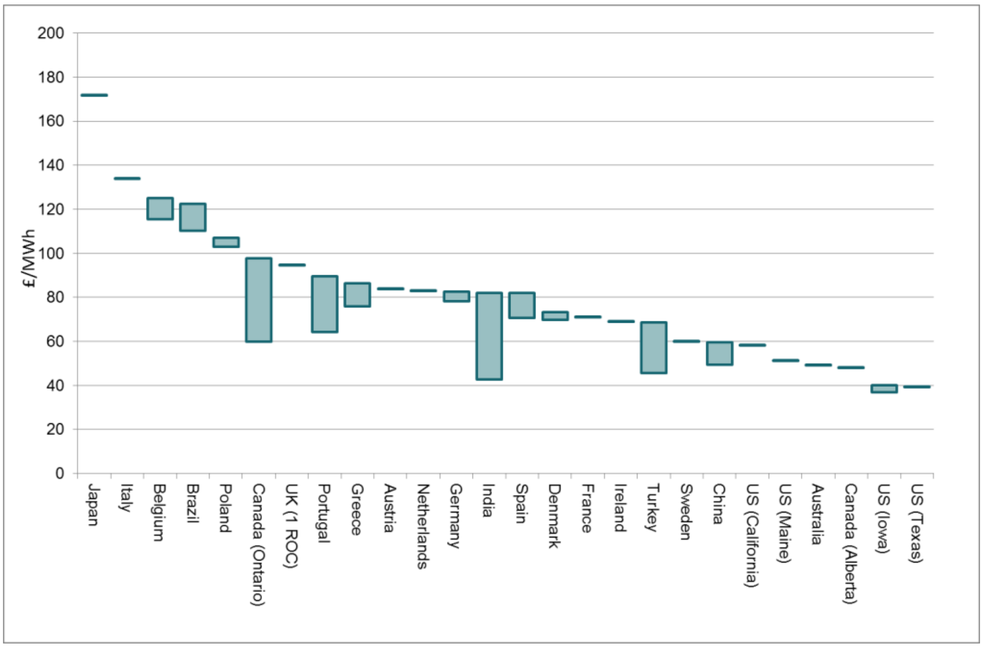
**Table 1.** Summary of average support levels in 2011 (£/MWh)

| Measure | UK value | International average | International median | International range | Quota average | FiT average | PFiT average |
|---|---|---|---|---|---|---|---|
| **Absolute support (market exchange rate)** | **95** | 77 | 70 | 37 to 172 | 75 | 81 | 69 |
| **Absolute support (PPP exchange rate)** | **95** | 82 | 79 | 33 to 180 | 80 | 92 | 65 |
| | | | | | | | |
| **Net support (market exchange rate)** | **47** | 34 | 29 | -1 to 79 | 39 | 35 | 26 |
| **Net support (PPP exchange rate)** | **47** | 35 | 29 | -2 to 106 | 42 | 34 | 26 |

Source: Data from various sources, analysis by Frontier Economics

Figure 2 shows the range of initial support levels for new plant in 2011 in absolute terms (the latest year for which consistent data was available for comparison). In many countries there is not a single support level for new plant as support is differentiated according to a number of factors (e.g. location, plant capacity and type of investor). At each different support the level of deployment can vary. Therefore average support levels in our view tend to be a more reliable measure by which to compare support levels. The graph shows a similar pattern to that for average support levels, with the UK support levels for new plant also in the top half of countries and regions examined.

**Figure 2.** Initial absolute support levels for new plant in 2011 (£/MWh, market exchange rates, 2011 prices)




Source: Data from various sources, analysis by Frontier Economics

The ROC multiple for onshore wind in the UK has reduced from 1.0 ROCs/MWh to 0.9 ROCs/MWh in April 2013. Based on 2011 support levels, the UK would still remain in the top half of countries examined after accounting for this reduction. Many other countries are also reducing support for onshore wind (see Section 3).

## EXPLAINING THE DIFFERENCES IN SUPPORT LEVELS

There are many reasons that may explain the differences in support levels including differences in costs, load factors and the nature of the support scheme as well as the level of political support for onshore wind. Although there is a large amount of uncertainty and variability around international cost estimates for onshore wind, **our analysis suggests that differences in estimated costs and load factors explain a large amount of the differences in support levels**. Countries with higher costs and lower average load factors tend to have higher support levels for onshore wind.

We analysed the reasons for differences in support levels from the UK using five international case studies. A summary of the case study countries is provided below.

**Table 2.** Summary of case studies

| | UK | Denmark | Germany | Ireland | Netherlands | Poland |
|---|---|---|---|---|---|---|
| Installed onshore wind capacity in 2011 (MW) | 4,650 | 3,081 | 28,860 | 1,608 | 2,100 | 1,616 |
| Proportion of demand met from onshore wind, 2011 (%) | 3% | 18% | 8% | 14% | 4% | 1% |
| Density of capacity (kW/square km) | 19 | 72 | 81 | 23 | 51 | 5 |
| Population density (persons/square km) | 259 | 130 | 229 | 65 | 403 | 123 |
| Capacity added in 2011 (MW, % increase) | 613 (13%) | 146 (5%) | 2,007 (7%) | 239 (17%) | 123 (6%) | 436 (37%) |
| Main support scheme type | Quota | PFiT | FiT | FiT (CfD) | FiT (CfD) | Quota |
| Date of introduction | 2002 | 2005 | 2000 | 2006 | 2008 | 2005 |
| Onshore wind ambition | 10-13 GW by 2020[7] | 50% of demand by 2020[8] | 36 GW by 2020 | 3.5 GW by 2020[9] | 6 GW by 2020 | 6.7 GW by 2020 |

Source: Various sources

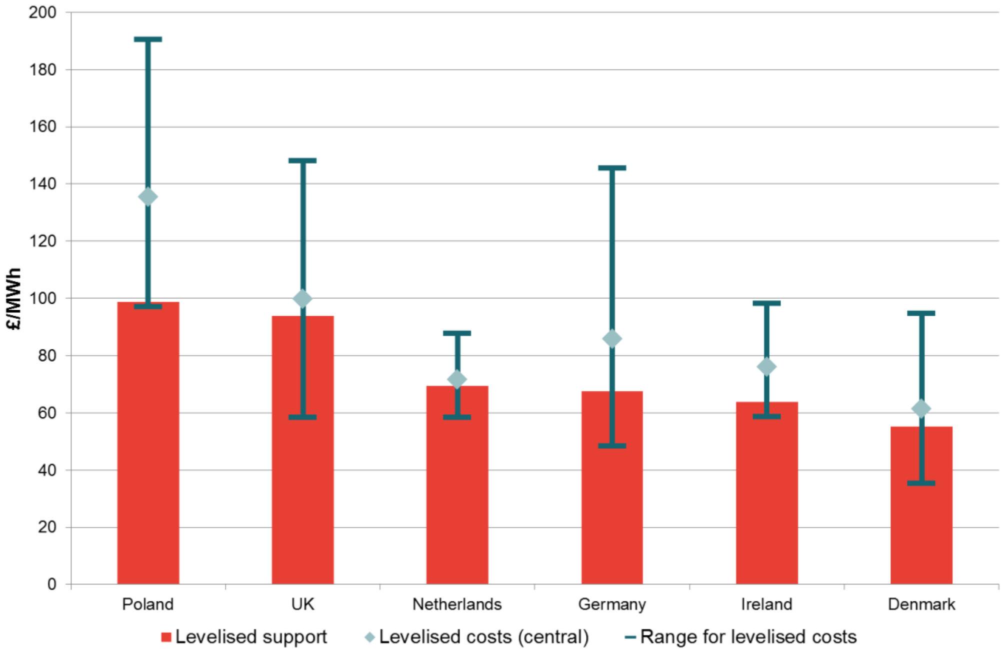
Our analysis suggests that differences in estimated levelised costs, which measures the total discounted costs per MWh of generation, are the most important factor in explaining differences in support levels between the UK and other countries. Figure 3 compares levelised costs in 2011 for new plant to levelised absolute support levels. It shows that, while there is high variability and uncertainty around levelised costs, the countries with higher costs also tend to have higher support levels.

7 DECC, 2011, *Renewable Energy Roadmap*.

8 This includes offshore wind which currently represents around one-third of wind generation in Denmark.

9 This includes offshore and onshore wind but the vast majority is expected to come from onshore.

**Figure 3.** Levelised absolute support levels and levelised costs for large-scale onshore wind in 2011 (£/MWh, market exchange rates)




Source: Data from various sources, analysis by Frontier Economics.

Figure 3 shows that our central estimates of levelised costs for plant commissioning in 2011 were relatively high in the UK at around £100/MWh (this is a Frontier estimate based on cost and load factors used for the banding review). There are three main reasons for this.

- **Higher capital costs**. Central capital costs estimates based on those used by DECC for the banding review in the UK are, with the exception of Ireland, around £0.3 - 0.4m/MW higher than those in other case study countries. This is equivalent to around £15 - 20/MWh in levelised costs (15 – 20% of overall levelised costs). The explanation for these higher cost estimates is uncertain. Some evidence suggests that higher construction, infrastructure and foundation costs are a major driver of this difference (which may reflect more difficult soil and access conditions in the UK) while small differences in turbine costs and connection costs may also have a minor influence.

- **Higher costs of capital**. In the UK the central WACC[10] assumed for the government response to the RO Banding review of 9.6% (pre-tax, real). This

10 Weighted average cost of capital (WACC). This is rate on average that an investment must pay back to its debt and equity holders, taking into account the relative shares of debt and equity. The

is higher than those cited in most other countries which are typically in the range 6% to 8% (with the exception of Poland). In some cases this may be partially explained by differences in the nature of support regimes (e.g. whether generators are exposed to price risks) or the presence of state-backed financing (KfW loans have helped finance over 80% of installed wind in Germany). Higher development risks have also been cited as a possible reason, although we did not find strong evidence that these risks are higher in the UK and only a small proportion of capital is employed at this stage. Each percentage point drop in WACC, at UK cost levels, reduces levelised costs by around £5/MWh.

- **Higher operating costs**. Central estimates on operating costs in the UK are at least £5,000 - 10,000 MW/year higher than those in Denmark, Germany and the Netherlands. This is equivalent to £2 - 4/MWh in levelised costs. This can largely be explained by differences in transmission charges which are low or zero in these countries compared to £10,000/MW/year or higher in the UK[11].

Load factors are also important in explaining differences in levelised costs. However, with an estimated load factor of 29% for new plant on average, the UK compares well to other countries. Only Denmark and Ireland have higher expected average load factors.

To summarise the drivers of levelised cost differences, Figure 4 shows how UK levelised costs would be impacted if cost estimates from other countries were applied. In each case we take the central assumptions from the UK and apply the estimates for different countries for a specific parameter (e.g. capital costs) to see how this affects levelised costs. For example, for capital costs we hold all other assumptions fixed and show how the UK levelised costs would be affected if central capital costs estimates from other countries were applied.

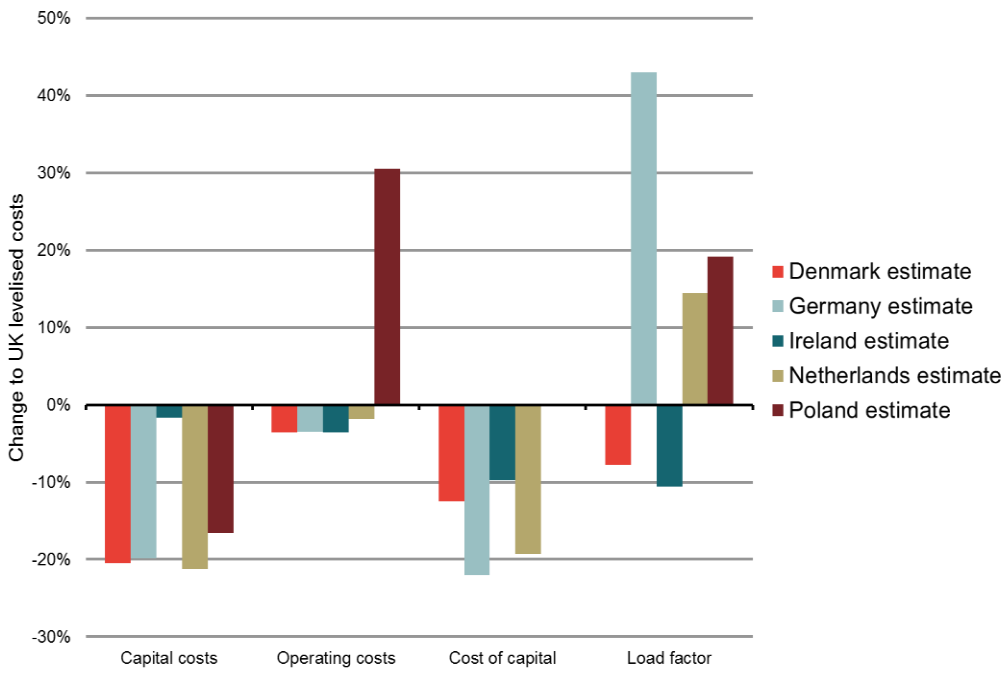
The figure shows that higher estimated capital costs and costs of capital are the main drivers of the higher estimated levelised costs in the UK.

---

WACC represents the minimum return that an investment must earn to cover its financing costs and is used to discount future cashflows.

11 In the UK 27% of transmission charges are levied on generation and are locational whereas the shares for Denmark, Germany and the Netherlands are 3%, 0% and 0% respectively - ENTSO-e (2012), *ENTSO-E Overview of transmission tariffs in Europe: Synthesis 2011*.

**Figure 4**. Changes to UK levelised costs from applying cost parameters from other countries




Source: Data from various sources, analysis by Frontier Economics

An important conclusion is that there are major differences in levelised costs across countries. **Therefore the efficiency of support regimes cannot simply be measured on the basis of average support levels**.

## DESIGN OF SUPPORT MECHANISMS

The way the support scheme is designed can influence the levels of support needed. Based on the analysis of the case studies, the following design features are important in determining the cost-effectiveness of deployment.

- **Differentiation between renewable technologies**. With the exception of Poland[12], all case study countries have differentiated support levels across renewable technologies. This has helped ensure that the cheaper technologies (including onshore wind and biomass co-firing) do not earn excess returns, improving the cost-effectiveness of support on an individual

12 Poland is now proposing to introduce technology banding which will reduce the support levels for onshore wind.

technology basis. However, this can limit the incentives to deploy the cheapest technologies first.

- **Differentiation between onshore windfarms**. In Germany and Denmark, because the support duration is linked to load factors, higher yielding sites with lower levelised costs receive less support. This has helped to reduce excess rents and make lower yielding sites more viable. However, the trade-off is that incentives to exploit the best sites can be reduced and it introduces complexity into the scheme.

- **Stability of support over time**. Stability of the available subsidies is clearly important. Germany has achieved relatively consistent levels of wind deployment with comparatively stable and well-signalled support levels. In the Netherlands deployment has been disrupted in recent years as the support mechanism has changed while in Denmark deployment stagnated for a period as support levels dropped.

# 1 Introduction

Support for renewable generation is an important part of the Government's energy policy. The mechanisms and levels of support need to be carefully designed so that they are deployed in a cost-effective manner, minimising costs to consumers while ensuring the renewables industry develops effectively.

Frontier Economics[13] has been commissioned by DECC to undertake an evidence review of onshore wind electricity generation, focusing on international evidence of government initiatives to support investment and deployment in onshore wind electricity generation. The project seeks to address two questions.

- How do the UK's support levels compare to those in other countries?
- What explains the differences in support levels and effectiveness of schemes in other countries?

There are three main sections in this report.

- We begin this report by setting out the methodology we have used to collect evidence and make inter-country comparisons and the assumptions used to make any comparisons.
- We then outline the key findings of the international review of onshore wind support. This includes an overview of support schemes found internationally and comparisons of the levels of this support. Because the review is broad in scope (we have reviewed 26 countries and regions in total) the comparisons are, by necessity, 'high-level'.
- We then consider the reasons for differences in support levels from the UK using five case study countries (Denmark, Germany, Ireland, Netherlands and Poland). This includes analysis of the country context, the nature of support schemes, levelised costs and other factors influencing deployment such as planning and grid access.

We provide further detail for each case study, the references used and a glossary in the annexes to this report.

13 We were assisted in this project by Frontier Economics (Australia) Pty Ltd and London Economics International (LEI).

# 2 Methodology

In this section we first describe the methodology used to calculate and compare the levels of support across countries and regions. We then set out the framework we used to analyse the reasons for differences in support levels across the more limited number of case studies.

## 2.1 Comparing international support for onshore wind

### 2.1.1 Scope

We selected the countries to be analysed based on the criterion that they had installed onshore wind capacity of at least 1,000 MW in 2011. This sample consists of 22 countries.

Within countries there can be some diversity in support types and levels. This is particularly true of the USA and Canada. Therefore we consider a sample of states and regions which are representative of the main support regimes within these countries and which have seen substantial onshore wind deployment. Including these regions takes the number of support regimes considered to 26.

### 2.1.2 Data collection

All data was collected for 2011 and all financial measures were taken in local currency in 2011 prices. We chose this year as the latest year for which consistent and comprehensive data was available for all countries and regions. We collected the following evidence for each country and region.

- **Market context**. This includes onshore wind capacity and generation in 2011[14] along with context on the drivers of onshore wind support (e.g. renewables targets) and barriers (e.g. planning).

- **Main support scheme(s)**. This includes details on the average and range of support levels available through the scheme. It also includes a description of how the support scheme operates and other conditions such as the duration of support.

- **Market prices**. Data on average wholesale prices (see Section 2.2.3) and any carbon prices.

[14] 2011 was chosen as the primary year for data analysis since it is the latest year for which data has been published for all countries in the study.

- **Other support measures**. This includes details of the operation and levels of tax incentives, loan guarantees, R&D support and special provisions for planning and grid access.

A full pro-forma for this data collection exercise is provided in the Annexes.

This data was gathered from a range of sources (e.g. energy ministries, regulators, system operators, power exchanges, wind energy associations). Where possible we have used primary local sources (e.g. country energy ministries) as these are likely to be more reliable before using secondary evidence (e.g. other international reviews of renewables support). We discuss the validation of the data later in this section.

### 2.1.3 Key metrics

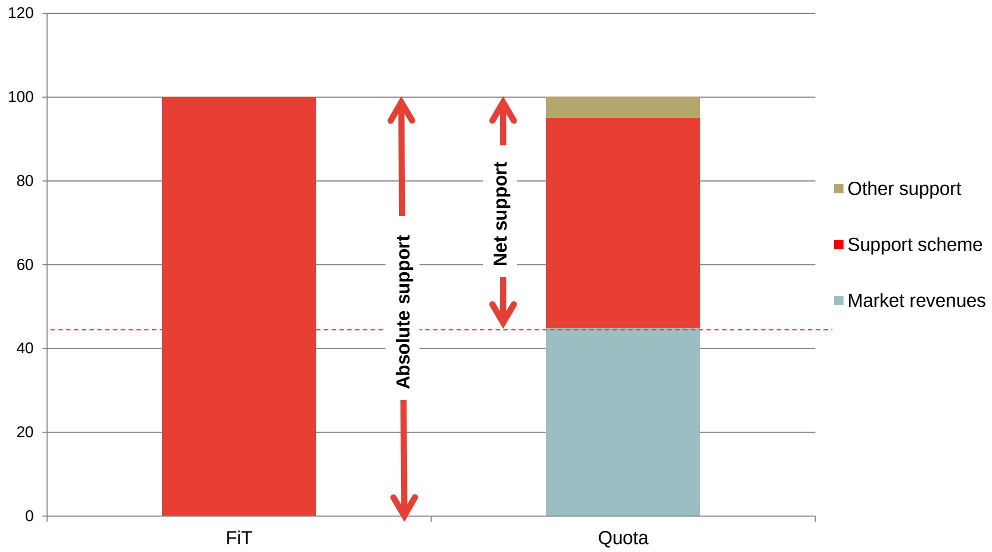
To compare support levels across countries and regions, we consider two main metrics:

- **Absolute support to wind generators**. This is the sum of the support received and any market based revenues that onshore wind generators receive. For example, a full feed-in tariff (FiT) provides a single revenue stream and generators do not receive any wholesale market revenues. Therefore, market revenues are excluded from the calculation of absolute support for FiTs. In the case of the Renewables Obligation (RO) or a Premium Feed-in Tariff (PFiT), wind generators receive support in addition to (wholesale) electricity market revenues and so market revenues are included in the calculation of absolute support.

- **Net support to wind generators**. This is the difference between the absolute support metric described above and the value of the wind energy generated as measured by the wholesale price. In the case of the Renewable Obligation (RO) or a Premium Feed-in Tariff (PFiT) this would simply be the value of support granted in addition to the wholesale market revenues earned. For a FiT the value of wholesale revenues (that would have been earned were a generator to sell directly into the market) must be netted off to give the level of support additional to what the market would have provided.

The distinction between absolute and net support is shown in Figure 5 for hypothetical FiT and Quota schemes. More detailed descriptions of how different support schemes operate are provided in Section 3.

**Figure 5**. Illustration of the difference between 'absolute support' and 'net support'




Source: Frontier Economics

For the purpose of comparison, the absolute support level is a more meaningful measure of the overall costs of wind deployment, particularly given that some indirect support (such as carbon prices) is embedded into wholesale electricity prices. However, net payments are also important evidence in understanding the extent to which onshore wind is reliant on direct government support. This is why we consider both measures.

We also distinguish between also 'average' support levels in 2011 and support levels for 'new' plant in 2011.

- **Average support levels**. This is the average level of support provided to all onshore plant in operation in 2011. This measure captures the fact that wind farms may be receiving different levels of support (e.g. according to when they were installed or their capacity)

- **Support levels for new plant**. This is the support level provide to new plant commissioning in 2011. Often there is a range of support levels for new plant (e.g. depending on capacity or location) and therefore in these cases a range is provided.

Finally we calculate the support comparisons on the basis of both market and purchasing power parity exchange rates. This is discussed later in more detail.

### 2.1.4 Analysis of the data

To compare support levels in a consistent way, we converted the support available from the main support schemes into a comparable (£/MWh) metric to measure the 'absolute' and 'net' levels of support. This section summarises this process.

#### *Calculating average support levels*

To calculate the average support levels, we include support available from all the main support schemes in the country/region. Where countries have multiple alternative support schemes we choose the scheme which includes the highest volume of wind generation (for example, for the UK we choose the RO rather than the FiT). We also include other output-based incentives (i.e. those whose value is realised on a 'per MWh' basis) that are additional to these, such as production tax credits, as these are an important component of onshore wind support, particularly in the US (see Section 3.1).

In some countries support levels differ depending on the type of installation (e.g. defined by level of capacity) or depending on how long ago the wind farm was commissioned. To capture these variations and obtain an 'average support' level we have applied the following methods.

- **'Top-down'.** Where data was available, the average support level was calculated by dividing the total payments to onshore wind in 2011 (£/year) by the amount of supported generation (MWh).

- **'Bottom-up'.** In many cases, particularly quota schemes, all wind generation in the scheme receives the same level of support and therefore the average (net) support level is simply the support payment or certificate price.

In a few cases, data was not available on overall support to calculate a 'top-down' average and there were some differentials in support levels[15]. In these cases we either based support levels on current support offered for new plant (where the support levels have not varied significantly over time) or on the mid-point of the range of support levels (where the range was small) for wind plant of different vintages.

#### *Calculating absolute and net support*

As discussed earlier, some support schemes include the market value of wind energy (FiTs) while others are paid in addition to revenues from the sale of wind power into wholesale or retail markets. Therefore, to calculate consistent measures of absolute and net support we need to measure the market value of wind energy. We use average day-ahead 'baseload' electricity prices as a proxy for

15 This was the case for France, Greece, Ireland and Poland.

the market value of wind in a given country/region[16] as this is the most robust measure for which data is widely available.

For some countries this may not fully reflect the average price captured by wind for two reasons:

- the pattern of wind speeds/generation may be weighted more heavily towards certain times of day when the prevailing price may be higher or lower than average; and
- in countries with a high proportion of wind generation there can be a negative correlation between wind generation and hourly wholesale prices[17,18].

We consider these effects in the detailed case studies.

### Converting support from local currencies into UK currency

To convert the support levels from local currency to GB pounds we use both market and purchasing-power-parity (PPP) average exchange rates for 2011[19]. Comparisons based on PPP exchange rates may be more meaningful given that (i) market exchange rates can be volatile; and (ii) PPP rates account for differences in price levels in countries thus allowing for fairer comparisons. However, market exchange rates may be the relevant comparison for global investors.

### Adjusting for the duration of support

The duration over which support is provided varies significantly across schemes. To provide a measure that is adjusted for duration, we have provided a 'duration-adjusted' measure of net support levels[20]. This aims to show equivalent levels of support if all support was provided over 20 years (as in the UK). This is calculated as follows:

- The 'present value (PV) of net support' per MW of capacity is calculated using the support level (£/MWh), the support duration and a discount rate of 10%[21].

---

16 This is the average time-weighted price for electricity and robust data for this is generally available.

17 For example, in Germany the average price captured by wind has been estimated to be between 88% and 95% of the average baseload price over the past 6 years. Frauenhofer institute (2012), *Direktvermarktung: Gleitende Marktpramie.*

18 We correct these potential biases by calculating a 'wind-weighted' average price in part two.

19 World Bank Data.

20 We do not provide this adjusted support measure for absolute support as windfarms will still expect to receive market revenues after support schemes expire. Therefore calculating the PV of support is more complex as future market prices would need to be accounted for.

21 In practice different discount rates will apply in each country but for consistency (and given we do not have the relevant discount rate for all 26 countries) we use a single rate.

- The 'PV of generation' per MW of capacity over 20 years is calculated. This is measured in MWh[22].

- Finally the 'PV of net support' is divided by the 'PV of generation' to provide an adjusted £/MWh support level which is based on 20 years of support

- For any scheme which provides 20 years of support the level is unchanged.

This calculation is summarised in the equation below.

$$Duration - adjusted\ support\ level\ (£\ per\ MWh)\ =\ \frac{PV\ of\ support\ (£\ per\ MW)}{PV\ of\ 20\ years\ generation\ (MWhs\ per\ MW)}$$

## 2.2 Explaining the differences in support levels

In this section we explain the methodology we used to analyse the reasons for differences in support for onshore wind using five case studies (Denmark, Germany, Ireland, Netherlands and Poland).

### 2.2.1 Evidence framework

We collected evidence and data in the following areas for each case study country.

- **The country context**, including the current levels of onshore wind deployment, political and public attitudes to onshore wind and indicators of the technical potential of onshore wind.

- **The main support scheme(s)**, including:
  - current support levels, including any market revenues, and key features of how the support scheme functions; and
  - historical support levels under the main support scheme(s) and how these have compared with onshore wind deployment rates.

- **Costs of wind deployment**, including:
  - capital costs, including turbine, construction, grid connection and pre-development costs;

22 NB. These adjusted support levels are not dependent on the load factor assumed as this appears in both the denominator and the numerator of the above equation. We present the equation in this way as it is conceptually more meaningful.

  - operating costs, including maintenance, insurance, land rent and grid charges;
  - costs of capital, as measured by the prevailing pre-tax cost of capital; and
  - load factors for new projects.
- **Other factors influencing deployment,** including:
  - other support measures (e.g. separate support for small-scale wind, investment tax incentives, loan guarantees)
  - grid access; and
  - planning and community benefits.

In all case studies we use local currency and where pound equivalents at stated we have used the market exchange rate for that year.

### 2.2.2 Levelised costs

We used the data on costs described above to calculate levelised costs in each country for projects commissioning in 2011 using the standard methodology.

$$Levelised\ costs\ (£\ per\ MWh) = \frac{PV\ of\ costs\ (£\ per\ MW)}{PV\ of\ generation\ (MWhs\ per\ MW)}$$

To do this we have used the following parameters and assumptions.

- Capital costs, measured per MW installed. We assume capital costs are incurred in Year 0 of the project.
- Operating costs measured per MW per year. Where some of the operating costs are expressed per MWh we convert into an annual figure using the assumed load factor. We assume operating costs are incurred from Year 1 for the rest of the project's duration.
- Load factors measured as expected annual production as a proportion of maximum output for new wind farms.
- Pre-tax, real weighted-average costs of capital (WACCs) for the discount rates which are country-specific.
- In all cases we have assumed the project operates for 20 years.

The methodology used in this report differs from the methodology used by DECC to generate levelised costs of electricity generation[23]. These differences are due to a number of factors, but primarily due to DECC modelling taking into account more factors and a more detailed understanding of project costs and timings. Our methodology is simplified for ease of comparison across countries and with support levels (e.g. we assume at 20 year operational period in all countries and that capital costs are all incurred in Year 0). Therefore, the levelised costs presented in this report are not directly comparable to levelised costs published by DECC.

It should be noted that levelised cost estimates are highly uncertain and subject to assumptions used for capital costs, operating costs, load factors, hurdle rates and changes in costs over time. It is often more appropriate to consider a range of cost estimates rather than single point estimates. We use a range of values for all of these parameters to provide sensitivities around a central levelised cost estimate. Where available, these ranges were based on the range of parameter values published. Where only a central estimate was available, we used sensitivities of +/- 10% of the central value. The case study sections detail these parameter assumptions.

We collected cost data for 2011. If 2011 data was not available, we converted to 2011 prices using GDP deflator inflation rates for the relevant country.

To calculate levelised costs (and levelised support) we discount using pre-tax real weighted average cost of capital (WACC). In the literature on costs of capital for onshore wind, WACCs are often quoted in post-tax or vanilla terms. We convert from these into pre-tax WACCs using the definitions and conversion equations:.

- Pre-tax WACC = (1-gearing) * r_e * 1/(1-t)+ gearing * r_d
- Post-tax WACC = (1-gearing) * r_e + gearing * r_d * (1-t)
- Pre-tax WACC = Post-tax WACC*1/(1-t)

Where r_d is the return on debt (pre-tax) and and r_e is the return on equity (post tax). Some WACCs are also quoted in nominal rather than real rates and we use standard average CPI inflation rates in each country to adjust into real terms.

### 2.2.3 Levelised support

Across the 5 case studies support is provided over different durations and with different grandfathering arrangements (e.g. nominal versus real). To adjust for these factors and to compare support levels with levelised costs on a consistent

[23] https://www.gov.uk/government/organisations/department-of-energy-climate-change/series/energy-generation-cost-projections

basis across countries we use a levelised measure of absolute support which is calculated as follows.

$$Levelised\ support\ \ (£\,per\,MWh)\ =\ \frac{PV\ of\ absolute\ support\ (£\,per\,MW)}{PV\ of\ 20\ years\ generation\ (MWhs\ per\ MW)}$$

We calculate the present value of absolute support over a 20 year time horizon taking into account following factors and simplifying assumptions.

- The support level from the scheme stays constant for the scheme's duration either in real or nominal terms at 2011 levels (e.g. for 20 years in the case of the UK). For countries where the support level (including the quota scheme buyout price) is linked to inflation we keep it constant in real terms. Where the support level is only fixed in nominal terms (e.g. Denmark, Germany) we deflate the real value over time according to a standard inflation rate of 2%.

- The support level available from market revenues stays constant for the duration of the project in real terms (we have assumed 20 years for all countries). We have assumed that a windfarm would receive market revenues between when the support scheme expires and the 20 year project horizon for FiT schemes where support is offered for less than 20 years.

In general, these calculations are not sensitive to load factors as this appears in both the denominator and numerator. The exception to this is for Denmark and Germany where the duration of support depends on the load factor. In these cases we calculate the duration of support based on central load factors.

## 2.3 Validation

The robustness of the evidence, data and analysis was an important part of this project. We have sought to validate the quality of the data and analysis in three ways.

- **Choice of sources and cross-checking**. In many case there were multiple sources from which we could take evidence. As the default we have used in-country sources which are usually the original source of the data (e.g. country energy ministries, energy agencies, regulators and market operators). We then used alternative sources (e.g. international reviews of onshore wind) to provide a cross-check on the data.

- **Internal quality assurance**. We used our regional experts to compile the evidence and to check the information in the first instance (including LEI for North America). Following this we have conducted a second validation of the data and analysis using experts from our London and Cologne offices.

- **Validation by external experts**. To gain an understanding of the case study countries we have spoken with our contacts in industry, government and trade associations in the relevant countries. We have also directly contacted authors of reports on costs we have cited to confirm data and definitions.

  We note that we received limited feedback on cost data from industry experts. For this reason all cost data presented here is derived directly from published sources. We note however that even these sources are reliant on surveys of industry and are subject to significant uncertainty.

# 3 Comparing international support for onshore wind

This section sets out the results of the international review of onshore wind support. This includes an overview of support schemes found internationally and comparisons of the levels of this support. Because the review is broad in scope (we have reviewed 26 countries and regions in total) the comparisons are, by necessity, 'high-level'.

## Key metrics used in this section

In measuring the levels of support internationally in this section we use a number of different measures. Support levels are provided on both an '**absolute**' (including market revenues) and '**net**' basis (excluding market revenues). Within these measures we make the following distinctions.

- **Average support levels**. This is the average level of support provided to all onshore plant in operation in 2011[24]. This captures the fact that in some countries plant in operation may be receiving different levels of support (e.g. according to capacity, location or year of installation). We also calculate a 'duration-adjusted' average support level.

- **Initial support levels for new plant**. This is the support provided to new plant commissioning in 2011 in its first year of operation. We measure this on an 'absolute' basis.

For the measures above we provide comparisons on both a market exchange rate and purchasing-power-parity (PPP) basis. The Methodology section provides a fuller explanation of these metrics.

## 3.1 Overview of international onshore wind support

This section summarises the international support landscape, including the most prevalent types of support found.

24 This calculated as the total support under the provided divided by the total generation under the main support scheme. Where support levels are differentiated this is therefore an average value weighted by the volume of generation at each support level.

### *Motivations and challenges for onshore wind support*

There are two main motivations for supporting onshore wind seen around the world;

- energy security and the desire to reduce a nation's dependence on fossil fuel; and
- reducing carbon emissions.

Countries place different emphasises on these depending on their domestic energy resources. In recent years, the desire to replace nuclear energy has emerged as a key motivation in countries such as Germany and Japan. Many countries also cite the desire to create jobs in a new industry as a rationale for support.

Most countries studied have set targets for the proportion of demand to be met from renewable (or low-carbon) sources although these vary in the level of ambition, the expected contribution from onshore wind and how binding they are. All EU member states have binding renewables targets and within these they set out wind-specific targets. Some EU countries (Austria, Germany and Denmark) have also chosen renewables targets that exceed those required under the EU target. The emphasis on onshore wind to meet these targets is largely influenced by the technical potential and cost-effectiveness of onshore wind compared to alternative renewable and low-carbon energy sources.

Finally, some constraints on development have emerged.

- The financial and debt crisis has reduced the ambition for renewables in some countries. While the headline targets have largely remained, support has been substantially reduced or suspended in many countries (notably Spain and Portugal).
- Some countries (e.g. Ireland, Italy, Spain and Portugal) with high wind penetrations in certain areas are also experiencing challenges in managing the volume and variability in wind power in terms of balancing the grid and managing constraints. This may constrain development[25].
- Availability of land and planning has been cited as a constraint on development in some countries (e.g. Netherlands, Poland and the UK).

### *Levels of onshore wind deployment*

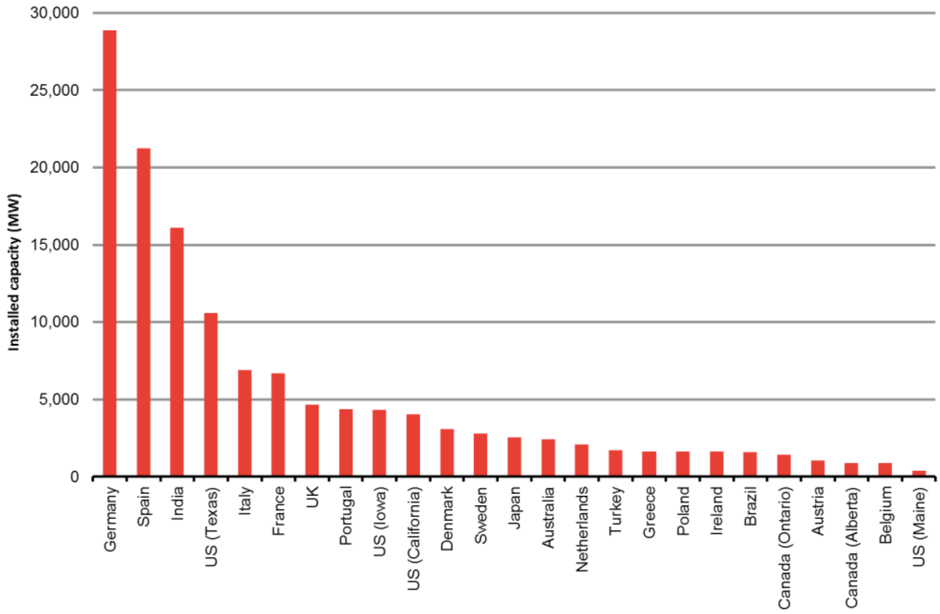
China (62 GW), Germany (29 GW) and Spain (21 GW) had the highest levels of installed wind capacity at the end of 2011. Figure 6 shows the installed capacity

---

25 IEA Wind (2011), *2011 Annual Report.*

of the countries and regions we have considered (where we have excluded China to make differences more comparable).

**Figure 6.** Installed capacity in 2011




Source: Data from various sources. China (62 GW) removed to improve comparability.

An alternative measure of wind deployment is the proportion of electricity demand met from onshore wind. On this measure Denmark (18%), Portugal (18%), Spain (16%) and Ireland (16%) have the highest levels of onshore wind with the UK standing at 3% in 2011[26].

## *Main support schemes*

The main support schemes for onshore wind deployment fit into four broad categories.

- **Quota scheme**. These schemes set an obligation on electricity suppliers to source a defined proportion of electricity from renewable sources, often with this proportion rising over time (in the UK this is termed as an obligation. In the US states it is generally termed as a Renewable Portfolio Standard).

  Typically a market for renewables certificates is created where each MWh of renewable generation receives a certificate. Suppliers can demonstrate their compliance with the quota by purchasing the certificates. The price of the

26 DECC (2012), *Onshore Wind Call for Evidence.*

certificate therefore represents the value of support and renewable generators also receive market revenues from trading in the wholesale market.

Many of these schemes include provisions which have the effect of stabilising certificate prices. For example, a buyout price which suppliers can pay as an alternative to purchasing certificates can result in an effective cap on certificate prices.

- **Premium Feed-in Tariff (PFiT).** Under these schemes, generators receive a fixed premium payment per MWh in addition to what they receive from selling into the wholesale or retail market.

- **Feed-in Tariff (FiT).** Under a classic FiT, generators receive a single fixed payment for their generation and they do not receive any revenues from sale of generation into the wholesale market. Typically a FiT also gives priority dispatch for renewable generation and they are not exposed to any balancing risks or costs. The market operator (or retailer) is required to purchase power from windfarms at the FiT rate and then market the power.

  Typically the support levels under a FiT are grandfathered at the point of plant commissioning for the duration of support eligibility (but often only in nominal rather than real terms). There are some schemes where the support rate is stepped down after a period[27].

  A digression rate is often applied to reduce (and sometimes increase) the tariff at which new plant joins the scheme over time and/or in relation to the volume of capacity being built.

- **Feed-in Tariff with Contract for Differences (CfD)**. This is a variant on a FiT and the PFiT. Like a classic FiT a stable overall payment for wind generation is targeted. However, unlike a classic FiT, generators still sell into the market. Premium payments are made according to the difference between the target price and a wholesale market reference price (e.g. average monthly day-ahead prices). The new CfD scheme being introduced under EMR would fall into this category. These schemes tend to substantially reduce wholesale price risks so are similar in effect to a FiT. However, unlike a FiT, a generator must sell into the wholesale market and may therefore potentially face balancing risks and, depending on what reference price is used, may face different degrees of 'basis risk' (this being the difference between the average price actually achieved by wind farms and the market reference price).

27 For example after ten years in France and five years in Germany the support level is stepped down according to the level of generation.

Typically these schemes include a number of different types of renewable technologies. Most of the time onshore wind will receive its own specific support rate although in some quota schemes a group of renewables may all receive the same support level.

Table 3 below shows where these different support schemes are used as the principle support scheme.

**Table 3.** Main international support scheme for onshore wind in use, 2011

| Quota | PFiT | FiT (classic) | FiT (CfD) |
|---|---|---|---|
| UK | Denmark | Austria | Ireland |
| Australia | Spain | Brazil | Netherlands |
| Belgium | | Ontario (Canada) | |
| Italy | | China | |
| Poland | | France | |
| Sweden | | Germany | |
| California (US) | | Greece | |
| Maine (US) | | India | |
| Texas (US) | | Japan | |
| | | Portugal | |
| | | Turkey | |

Note: Alberta (Canada) does not have a deployment support scheme and Iowa (US) uses tax credits as its principle support mechanism.

### *Other support*

In addition to the main support schemes, many countries also employ tax incentive schemes for onshore wind (or renewables generally). There are a wide variety of different tax incentives, the most prominent we have observed fall into two broad categories:

- **Output-based tax incentives**. There are a number of tax incentives that are related to output (MWh) from wind farms. In particular, the Production Tax Credit (PTC) which applies across the US provides a benefit of around £15/MWh for the first ten years of eligible wind generation in all states. Another example is the exemption from the climate change levy (CCL) in the UK which provided a benefit of around £5/MWh in 2011. The value of these incentives is typically expressed as a 'per MWh' figure and they often provide significant levels of support. Therefore we include them in the overall comparisons of support we undertake.

## Comparing international support for onshore wind

- **Investment tax incentives**. Another common class of tax incentive is that related to investment, including investment tax credits, capital allowances and accelerated depreciation. These schemes typically allow a proportion of the investment in wind generation to be used to offset income or corporation tax liabilities in the first few years of the project. They therefore have the effect of improving cash flows in the early years of the projects, thus aiding financing. Such schemes are in place in Canada, China, India, Ireland, Sweden and the US (as an alternative to the PTC described above)[28]. The strength of these incentives varies by country. Moreover, the value of these incentives to investors varies depending on a range of specific factors such as the profitability of the firm, its capital structure and the prevailing corporate tax rates. Because of this we do not include these in our quantitative comparisons of support levels in the next section.

Finally, there are also other forms of indirect support for onshore wind deployment. These include the following:

- **Loan guarantees**. A number of countries offer loan guarantees and/or low interest loans, both of which are aimed at reducing the cost of financing wind projects for some types of investors. The countries that have loan programmes include China, Denmark, Germany, Poland, Canada (Ontario) and the US (Federal, since expired, along with state level programs in some states). Again the terms and volumes of these offerings vary significantly.

- **R&D**. The extent to which current R&D programmes are helping to support onshore wind deployment is difficult to determine. Our review of current R&D spending suggests that it is having a limited impact on commercial deployment. Most R&D funding relevant to wind appears to focus on new types of turbines (e.g. larger, offshore), strategies for reducing O&M costs and wind resource assessment (including characterisation of terrains and wake effects). The turbines being deployed at present are typically mature technologies and therefore past R&D policies have had more of an influence on current deployment.

  A number of studies have suggested that past R&D programmes, such as in Denmark and Germany have significantly impacted on current deployment levels by promoting early deployment and developing domestic supply chains[29][30]. Given there is a global market for turbines it is however

28 Other countries also offer similar incentives for R&D investments (e.g. Turkey).

29 Neij, L. and Andersen, P (2012), *A Comparative Assessment of Wind Turbine Innovation and Diffusion Policies*. Historical Case Studies of Energy Technology Innovation.

30 Klaasen, G et al (2005), *The impact of R&D innovation for wind energy in Denmark, Germany and the United Kingdom*. Ecological Economics.

questionable how much of the technology gains are retained in the country that originally provided the R&D support.

- **Priority grid access**. A large number of countries (Belgium, Germany, Ireland, Italy, Poland and Turkey) state that they provide priority connection of renewables to the grid above other generation types. This sometimes includes discounts on connection costs (i.e. the amount charged to the network operator rather than the windfarm developer).

- **Special planning.** Some countries, such as Denmark, have introduced measures to help overcome local planning constraints such as mandatory community ownership and compensation for loss of property value from wind development. However, as these are typically obligations imposed on wind developers it is questionable whether they can be considered 'support'.

Again these forms of indirect support are not included in the '£/MWh' comparisons of support levels in the next section, although would be considered if the study progressed to part two.

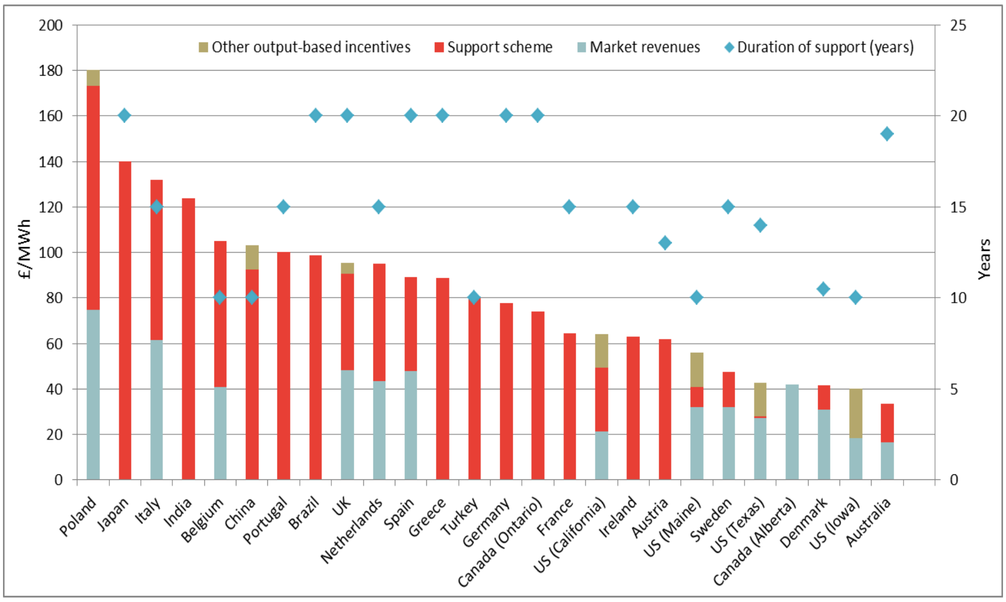
## 3.2 Comparing the levels of support

This section sets out our comparison of the levels of output-based support across countries and regions, including the main support scheme and other output-based incentives such as production tax credits and levy exemptions.

### 3.2.1 Average absolute support

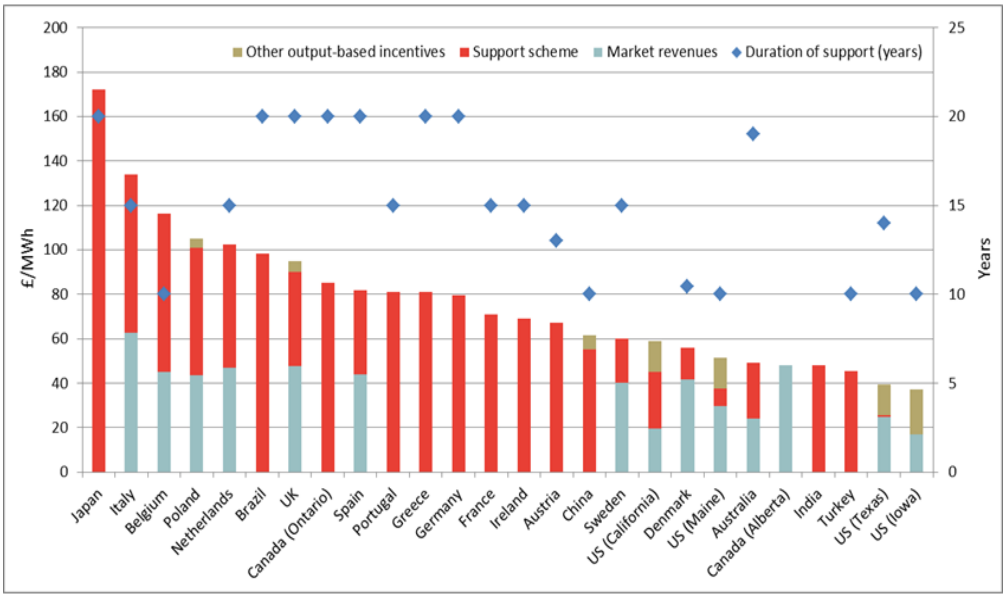
Figure 7 and Figure 8 show the average levels of absolute support (i.e. including any revenues from the wholesale market) for all onshore wind in operation in 2011 based on PPP and market exchange rates respectively. They also show the duration of eligibility for support (in years) for schemes where this is defined.

**Figure 7.** Comparison of absolute support levels (PPP exchange rates, £/MWh)




Source: Data from various sources, analysis by Frontier Economics

**Figure 8.** Comparison of absolute support levels (mkt exchange rates, £/MWh)




Source: Data from various sources, analysis by Frontier Economics

The absolute support for onshore wind in the UK in 2011 was around £95/MWh including the value of the wholesale revenues, Renewables Obligation Certificates (ROCs) and CCL exemption certificates (LECs)[31]. This sits within the

---

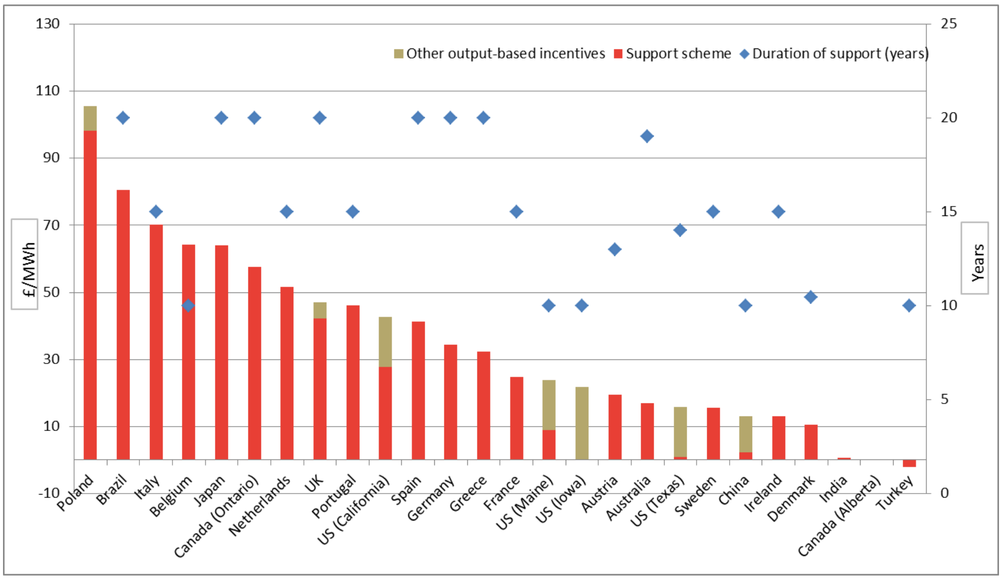
31 The value of the wholesale revenues is taken from the average APX baseload spot price (£48/MWh). For consistency with other estimates we do not adjust for the wind market value in this case but we do in the detailed case study. The value of the ROC in 2011/12 was £42/MWh

ranges for international support of £33/MWh to £180/MWh on a PPP basis and £37/MWh to £172/MWh on a market exchange rate basis. The average support levels (giving each country equal weight) was £82/MWh on a PPP basis and £77/MWh on a market exchange rate basis. In terms of duration of support, the UK sits at the top of the range of 9 to 20 years, with the RO offering 20 years of support.

### 3.2.2 Average net support.

Figure 9 and Figure 10 show the levels of net support for onshore wind (i.e. net of the market value of wind) based on market and PPP exchange rates respectively[32].

**Figure 9:** Comparison of net support levels (PPP exchange rates, £/MWh)

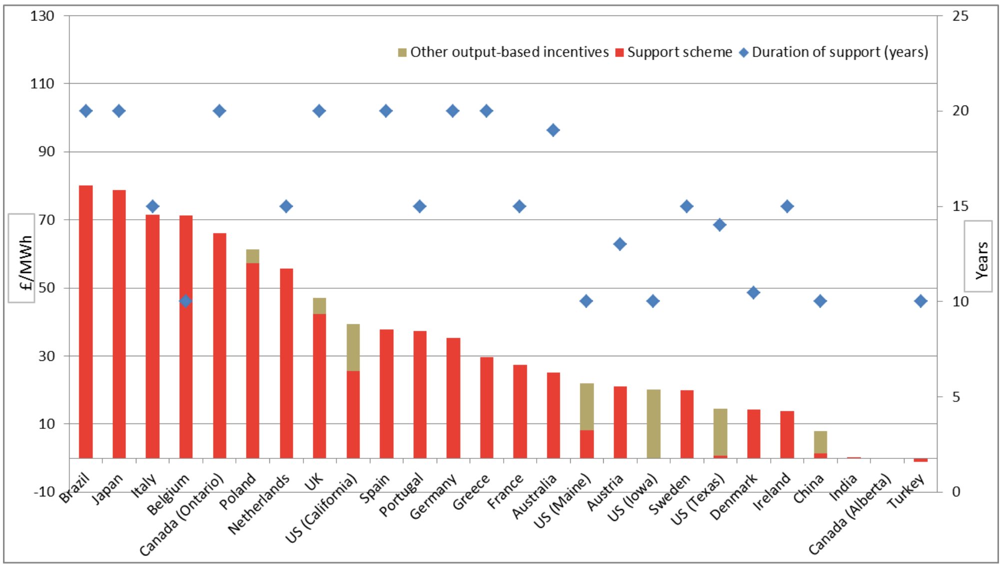



Source: Data from various sources, analysis by Frontier Economics

(according to the Renewables Annual report 2011/12 from Ofgem. The value of the LEC is £5/MWh.

32 The negative number at the bottom of these ranges is explained by Turkey where in 2011, the level of the FiT offered was in fact lower than the average market price. The FiT levels may have exceeded the average market price captured by wind producers but we don't have the data for this. The low levels of net subsidy may explain the low levels of take up for the scheme.

**Figure 10.** Comparison of net support levels (mkt exchange rates, £/MWh)




Source: Data from various sources, analysis by Frontier Economics

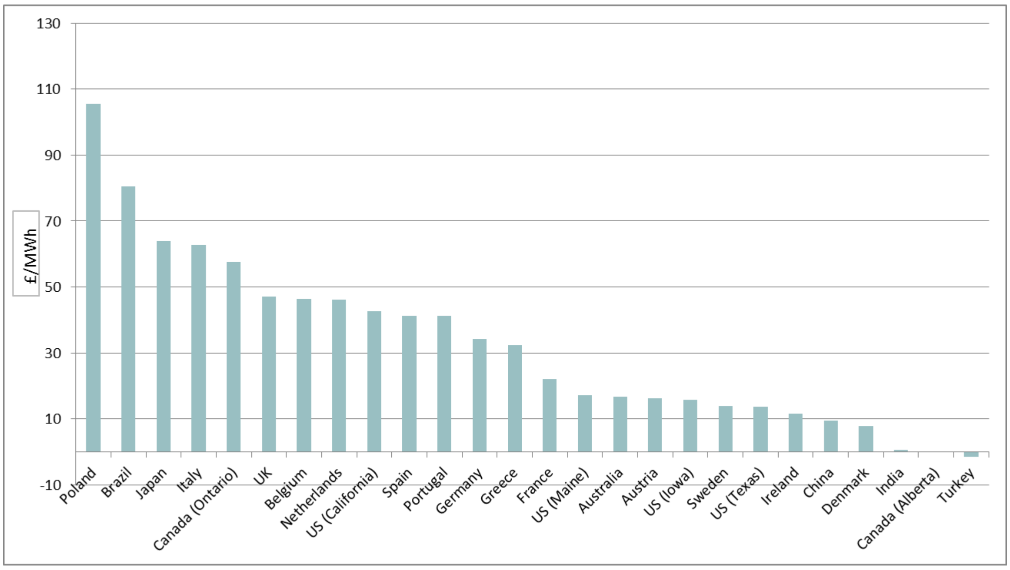
The net support for onshore wind in the UK in 2011 was around £47/MWh composed of the value of ROCs and LECs. This sits within the ranges for international support of minus £2/MWh to £106/MWh on a PPP basis and minus £1/MWh to £79/MWh on a market exchange rate basis[33]. The average support level (giving each country equal weight) was £35/MWh and £34/MWh on a PPP basis and market exchange rate basis respectively.

Finally, Figure 11 provides a comparison of net support levels on a 'duration-adjusted' basis. This is where the support is converted into a 20-year equivalent value (see Section 2.2.3). The effect of this is that the adjusted levels of support for schemes which offer support for less than 20 years fall. Again the UK sits in the top half of support levels.

---

33 The negative number at the bottom of these ranges is explained by Turkey where, in 2011, the level of the FiT offered was in fact lower than the average market price.

**Figure 11.** Duration-adjusted comparison of net support levels (PPP exchange rates, £/MWh)




Source: Data from various sources, analysis by Frontier Economics

Note: for schemes which do not specify the support duration we have assumed 20 years

### 3.2.3 Adjusting for risk transfers and 'hold up' costs associated with the support scheme

Risk may be an important consideration in comparing support levels. FiTs do not expose wind farm owners to wholesale price risk, transferring these to other parts of the market. The value of this risk protection to wind developers therefore needs to be considered in the overall assessment and comparison of support levels.

We make the following estimate of the value of protection from wholesale price risks on a per MWh basis.

- Removal of wholesale price risks via a FiT is estimated to reduce the WACC[34] for onshore wind by 0.5 percentage points (compared to a Quota or a Premium FiT)[35].
- We then calculated the reduction in levelised costs associated with this reduction in WACC based on an average load factor of 29% and capital

[34] The WACC for a project typically also represents its minimum hurdle rate as investors will only consider projects with returns which cover their cost of capital.

[35] DECC (2013), *Impact Assessment: Contacts for Differences*.

costs of £1.6m/MW[36] using the formula for levelised costs shown in Section 2.2.2.

- On a 'per MWh' basis the reduction in levelised costs is approximately £3.1/MWh for wind generators operating under a FiT compared to a Quota or Premium FiT scheme.

There is a high amount of uncertainty around this value. In particular, the value of this risk transfer will vary depending on the context, including how volatile and uncertain market prices are in a given country and the risk appetite of the investor. The 'per MWh' value is also sensitive to other factors such as capital costs and load factors.

Table 4 shows a sensitivity analysis of this to some key parameters. In the central case this risk transfer does not appear to be a major factor in explaining the differences in support levels. However, we do consider how differences in the costs of capital help explain differences in support levels in the next section.

**Table 4.** The value of risk transfer under a FiT compared to a Quota/PFiT scheme (2011 prices)

| | Low | Central | High |
|---|---|---|---|
| Reduction in WACC (%age points) | 0.3 | 0.5 | 0.7 |
| Capital costs (£m/MW) | 1.2 | 1.6 | 2.0 |
| Load factor (%) | 33 | 29 | 25 |
| **Value of risk transfer (£/MWh)** | **1.2** | **3.1** | **6.0** |

Source: Analysis by Frontier Economics. Central case reduction in WACC taken from DECC (2013), *Impact Assessment: Contracts for Differences* and the lower bound is based on Redpoint (2010), *Electricity Market Reform: Analysis of Policy Options*. The range of capital costs and load factors are based on numbers used by DECC for the banding review (converted into 2011 prices).

Related to this, the nature of the support scheme can impact on how much of the support feeds through the wind developers. For example it has been suggested in the UK that independent wind developers receive around 90% of the Renewables Obligation Certificate (ROC) value, 90% of the LEC value and 87% of the average wholesale price from purchasers of their generation[37].

We consider the reasons for this to include (i) that purchasers of generation may be taking risks around wholesale prices, ROC prices and balancing (ii) the average

36 This is the central assumption used by DECC in the banding review converted into 2011 prices.

37 Assumptions provided by DECC.

price that wind captures may be below the average wholesale price and (iii) there are administration costs associated with handling ROCs and trading generation. Under FiT schemes, independent developers are unlikely to face these discounts, as they are typically paid directly.

We do not factor this into our measures of average support levels because we are measuring the overall costs to consumers of support rather than amount developer actually receives. Moreover there is a large amount of uncertainty over the appropriate discounts to use and they will vary depending on the type of developer (e.g. independent versus integrated utility).

### 3.2.4 Summary of average support comparisons

Table 3 summarises the UK support levels in comparison to various international metrics. Absolute and net support levels in the UK are both in the top half of countries and regions examined. Out of the 27 countries and regions covered, the UK ranks as having the 7th to 9th highest support level, depending on the measure used.

**Table 5.** Summary of average support levels in 2011 (£/MWh)

| Measure | UK value | International average | International median | International range | Quota average | FiT average | PFiT average |
|---|---|---|---|---|---|---|---|
| **Absolute support (market exchange rate)** | **95** | 77 | 70 | 37 to 172 | 75 | 81 | 69 |
| **Absolute support (PPP exchange rate)** | **95** | 82 | 79 | 33 to 180 | 80 | 92 | 65 |
| | | | | | | | |
| **Net support (market exchange rate)** | **47** | 34 | 29 | -1 to 79 | 39 | 35 | 26 |
| **Net support (PPP exchange rate)** | **47** | 35 | 29 | -2 to 106 | 42 | 34 | 26 |

Source: Data from various sources, analysis by Frontier Economics

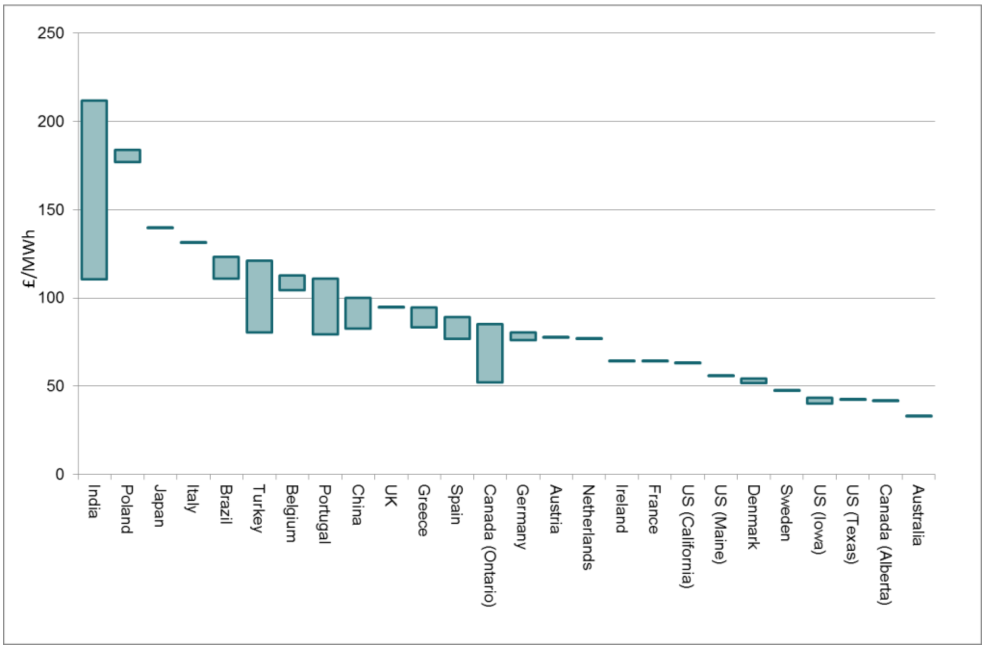
FiT schemes on average provide a higher level of absolute support than quota schemes whereas PFiT schemes offer a lower level (although only two countries operate PFiTs). However we do not believe these differences provide any indication of the effectiveness of the support scheme given the small sample and that a number of other factors drive support levels (e.g. costs and load factors).

### 3.2.5 Initial support levels for new plant

For new plant there can be a range of support levels offered within the same support scheme or from an alternative scheme in some countries. This variation can be linked to a number of factors including the capacity of the wind farm, the type of investor (e.g. independent generator versus integrated utility) and the location.

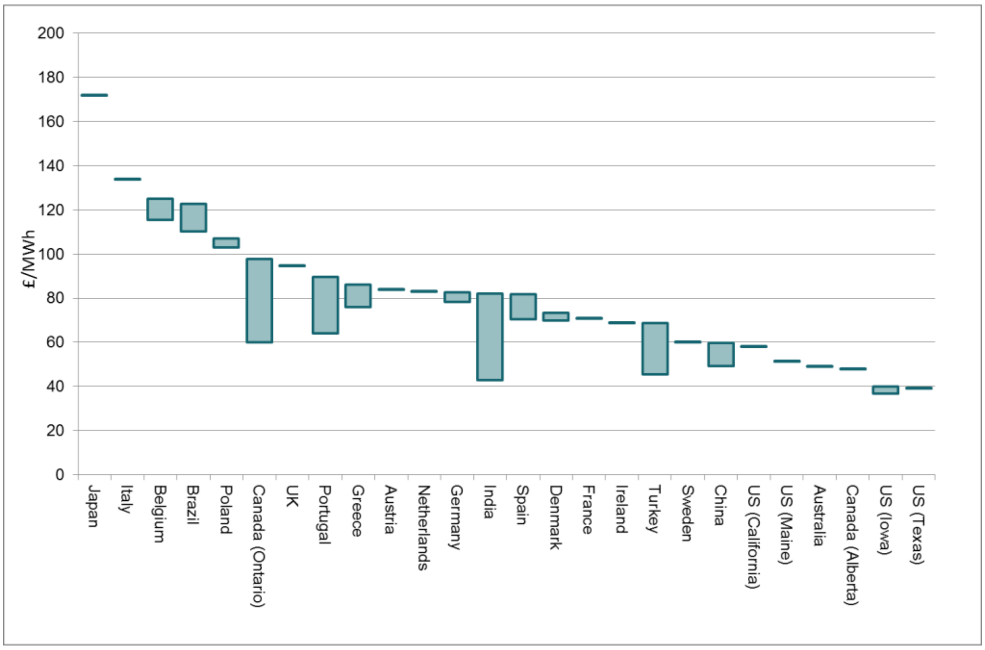
Figure 12 and Figure 13 show the range of support levels for new plant seen in 2011 on a PPP and market exchange rate basis respectively. It should be stressed that the levels of deployment at the ends of these ranges can be very small and therefore this figure may not provide a fair comparison of support levels in general. Moreover since these are new tariffs it is not yet clear whether substantial amount of wind will be deployed at these support levels. Therefore the average support levels we have used previously tend to be a more reliable general measure of support levels.

**Figure 12**. Range of absolute support levels for large-scale wind for new plant in 2011 (£/MWh, PPP exchange rates, 2011 prices)




Source: Data from various sources, analysis by Frontier Economics

**Figure 13.** Range of absolute support levels for large-scale wind for new plant in 2011 (£/MWh, market exchange rates, 2011 prices)




Source: Data from various sources, analysis by Frontier Economics

# Comparing international support for onshore wind

Since 2011 many countries have been amending the support levels for new onshore wind plant. The data is not available to compare these changes consistently for all countries and regions. However, the following summarises some key changes since 2011.

In the UK the ROC multiple for onshore wind will reduce from 1.0 ROCs/MWh to 0.9 ROCs/MWh in 2013. On the basis of support levels seen in 2011, this would still leave the UK in the top half of support levels. Under the quota scheme in Poland a similar approach is being proposed with multiples for large-scale onshore wind moving from 1.0 down to 0.9 in 2013, with further reductions by 2017.

In Spain and Portugal the main support schemes were suspended in 2012 as a consequence of the financial crisis.

In a number of other countries tariffs for new plant are degressed according to a formula. For example, in Germany tariffs have been reduced by 1% per year in nominal terms and in 2012 this rate was changed to 1.5% per year.

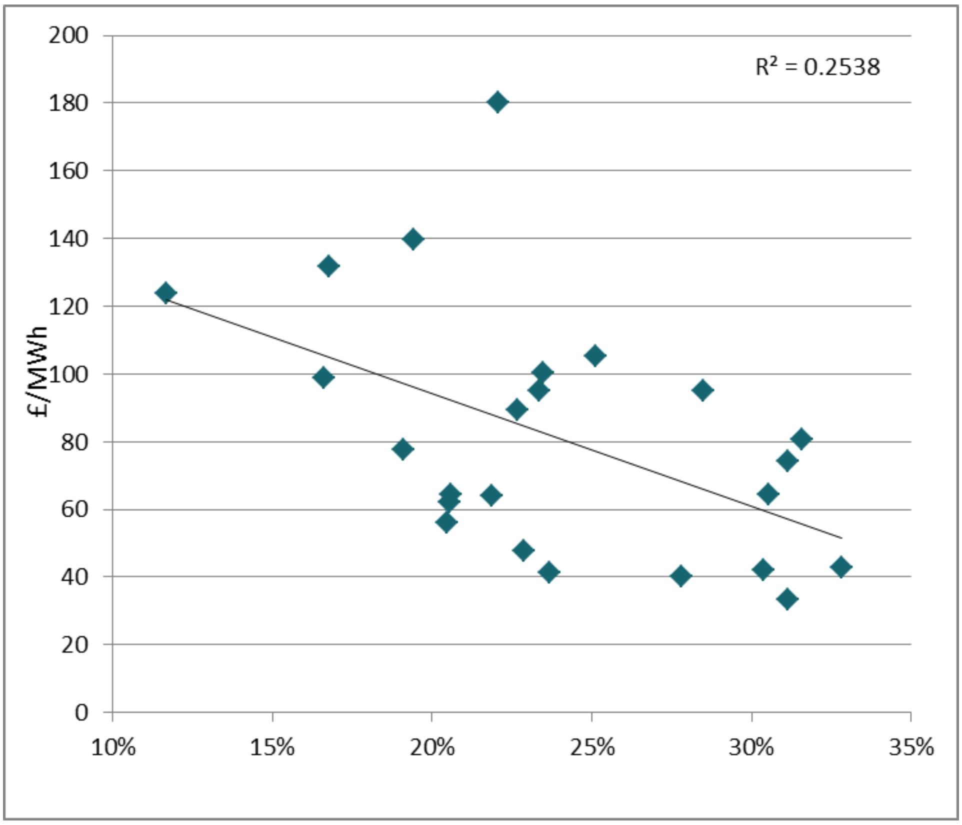
Finally some countries are reforming the nature of the support schemes themselves. For example, Germany now offers a PFiT scheme as an alternative to the FiT. In Italy the quota scheme has now been replaced with a FiT scheme. In the UK a FiT (CfD) scheme will be available from 2014.

### 3.2.6 Potential reasons for differences in support levels

There are a number of possible explanations for the differences in support levels observed that are suggested by the evidence gathered.

- **Differences wind load factors**. Some countries with high support levels also have relatively low average load factors (resulting from lower than average wind speeds). Therefore wind farms require a higher level of support on a 'per MWh' basis in order to be commercially viable. Figure 14 shows a negative correlation between average support levels and to load factors in 2011 by country/region. However, the strength of this correlation is not strong with an $R^2$ of only 26% (rising to 32% if Poland, the high outlier, is removed).

**Figure 14.** Average absolute support levels (£/MWh, PPP basis) versus average load factors in 2011




Source: Data from various sources, analysis by Frontier Economics

- **Costs can vary across countries** (e.g. turbine costs, construction costs and transmission charges) which in turn affects the support levels needed to stimulate deployment. We investigate cost differences in detail in the next section.

- **Differences in the type of support scheme**. Some countries with relatively high support levels run under quota schemes. In these cases the prices of certificates may not be linked to onshore wind costs. For example they may be linked to the size of the quota obligation and the buyout price and/or by other more expensive renewable generation types included in the scheme.

- **Differences in political and public support for onshore wind**. Some governments do not appear to have a strong desire to accelerate onshore wind deployment and therefore the levels of support may reflect this.

We explore these factors through 5 detailed case studies in the next section.

# 4 Explaining differences in support levels

Our review of the support schemes across the 26 countries and regions showed that there are some large differences in support levels. We now analyse these reasons for differences using detailed case studies to compare with the UK. Five case studies are considered: Denmark, Germany, Netherlands, Republic of Ireland and Poland. The choice of case studies was made by DECC following discussions with Frontier and a peer reviewer.

In each case study we look at four areas.

- **The country context**. This includes the current levels of onshore wind deployment, political and public attitudes to onshore wind and indicators of the technical potential of onshore wind.
- **The main support scheme(s)**. This includes:
  - current support levels, including any market revenues, and the main features of how the support scheme functions; and
  - historical support levels for new plant under the main support scheme(s) and how these have compared with onshore wind deployment rates.
- **Costs of wind deployment**. This analyses the costs of wind deployment across four categories:
  - capital costs, including turbine, construction, grid connection and pre-development costs;
  - operating costs, including maintenance, insurance, land rent and grid charges;
  - costs of capital, as measured by the prevailing pre-tax cost of capital for onshore wind investment in the context of the case study country; and
  - load factors for new projects.

  These factors are then combined to provide estimates of levelised costs which are compared to current support levels.
- **Other factors influencing deployment**. This considers other factors which affect the costs and levels of deployment including other support measures, grid access and planning.

These factors are discussed in detail for each case study in the annexes. The rest of this section compares the case studies countries and what is driving the differences in support. In particular, we compare costs and load factors across countries, which play a major role in explaining differences in support levels.

## Key metrics used in this section

In explaining the differences in support levels in this section we use the following measures of support.

- **The initial absolute support rate for new plant**. This is the absolute support level (including market revenues) that wind farms commissioning in 2011 receive in their first year of operation.

- **Levelised absolute support for new plant**. This is a discounted average measure of support levels for projects commissioning in 2011 over the course of the project (20 years). In this we take into account the duration of support and grandfathering arrangements (i.e. whether support is grandfathered in real or nominal terms). A full explanation of this metric is provided in the Methodology section.

We only provide these measures on market exchange rate basis in this section as some elements of the costs we are comparing them to (in particular turbines) are traded internationally.

## 4.1 Country context

Table 6 provides an overview of the case study countries.

**Table 6.** Summary of case studies

| | UK | Denmark | Germany | Ireland | Netherlands | Poland |
|---|---|---|---|---|---|---|
| Installed onshore wind capacity in 2011 (MW) | 4,650 | 3,081 | 28,860 | 1,608 | 2,100 | 1,616 |
| Proportion of demand met from onshore wind, 2011 (%) | 3% | 18% | 8% | 14% | 4% | 1% |
| Density of capacity (kW/square km) | 19 | 72 | 81 | 23 | 51 | 5 |
| Population density (persons/square km) | 259 | 130 | 229 | 65 | 403 | 123 |
| Capacity added in 2011 (MW, % increase) | 613 (13%) | 146 (5%) | 2,007 (7%) | 239 (17%) | 123 (6%) | 436 (37%) |
| Main support scheme type | Quota | PFiT | FiT | FiT (CfD) | FiT (CfD) | Quota |
| Date of introduction | 2002 | 2005 | 2000 | 2006 | 2008 | 2005 |
| Onshore wind ambition | 10-13 GW by 2020[38] | 50% of demand by 2020[39] | 36 GW by 2020 | 3.5 GW by 2020[40] | 6 GW by 2020 | 6.7 GW by 2020 |

Source: Various sources

The levels of wind capacity installed and proportion of demand met from wind varies significantly across the case studies. Germany has the highest levels of capacity installed while Denmark has the largest share of demand met from onshore wind. In terms of the density of wind capacity relative to land area, Denmark and Germany have roughly four times the UK level. Germany also had by far the highest deployment rate in 2011 at over 2000 MW. Relative to existing capacity Ireland and Poland grew at the fastest rates during 2011.

All counties are planning for onshore wind to make a substantial contribution to meeting their EU renewable targets. Denmark has an ambition to exceed the

38 DECC, 2011, *Renewable Energy Roadmap*.

39 This includes offshore wind which currently represents around one-third of wind generation in Denmark.

40 This includes offshore and onshore wind but the vast majority is expected to come from onshore.

amount required under the EU target while Germany is expected to exceed its onshore wind ambition of 36 GW by 2020. The Netherlands have also targeted 16% of their energy to come from renewables, above the 14% required under the EU renewables target.

As regards public attitudes to onshore wind, support in Denmark has been very strong (e.g. 96% of the public are in favour according to a survey[41]). The public are also reasonably supportive of onshore wind in other countries including the UK, although public support in Poland is more mixed. There are some signs that in Germany that the impacts on consumer bills of the high levels of renewables support are not generally supported. The annexes provide more details on public support in the case study countries.

Population density and capacity density (i.e. the amount of onshore wind capacity per square kilometre) also provide some indication of the build potential for onshore wind. In the Netherlands, population density is very high which will potentially place more constraints (i.e. in accessing land and obtaining planning permission) on build than other countries. The UK has a similar population density to Germany. Given that Germany has achieved a density of onshore wind capacity 4 times that of the UK, this suggests that the UK's population density should not necessarily be a barrier to growth at this stage.

## 4.2 Main support scheme and support levels

The case studies include a range of main support schemes.

- The UK and Poland use a quota scheme.
- In Germany a FiT scheme is used (and from 2012 the option of a PFiT scheme has also been offered).
- Ireland and the Netherlands use a FiT (CfD) scheme where a variable premium is paid according the difference between wholesale prices and a defined target price. In Ireland the scheme operates as a floor price.
- Denmark uses a PFiT scheme where a premium is paid on top of market revenues.

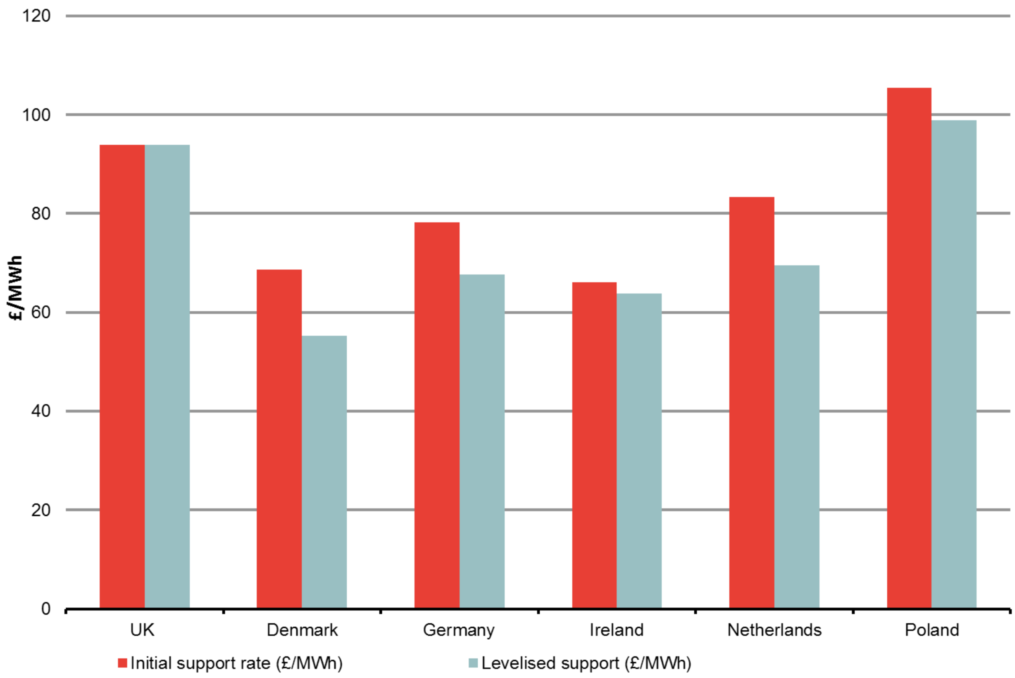
The annexes provide detailed explanations of how these support schemes are designed.

Figure 15 shows the absolute support levels for new plant in 2011. We present this as both the initial support rate and a levelised support rate which accounts

41 AC Nielsen Survey (2006), cited in Jakob Lau Holst, *Danes are Wild about Wind.*

for differences in the duration of support and grandfathering arrangements (e.g. whether it is grandfathered in real or nominal terms)[42].

**Figure 15.** Initial absolute support levels and 'levelised' support levels for onshore wind in 2011 (market exchange rates, £/MWh)




Source: Data from various sources, analysis by Frontier Economics

Support levels in the UK in 2011 were higher than other case study countries, with the exception of Poland. The fact that support is provided over 20 years and that the buyout price is linked to inflation also ensures the level of support is sustained over the course of the project. We provide trends on how these support levels have changed over time in annexes.

## 4.3 Costs of deployment

This section summarises our comparison of levelised cost estimates across the case study countries. We believe these are a major driver of differences in support levels. We show how levelised costs compare to support levels, and explain some of the potential reasons driving differences in levelised costs.

We stress there is a high level of uncertainty and variation around cost estimates. First, data has been collected from different sources in each country, typically via

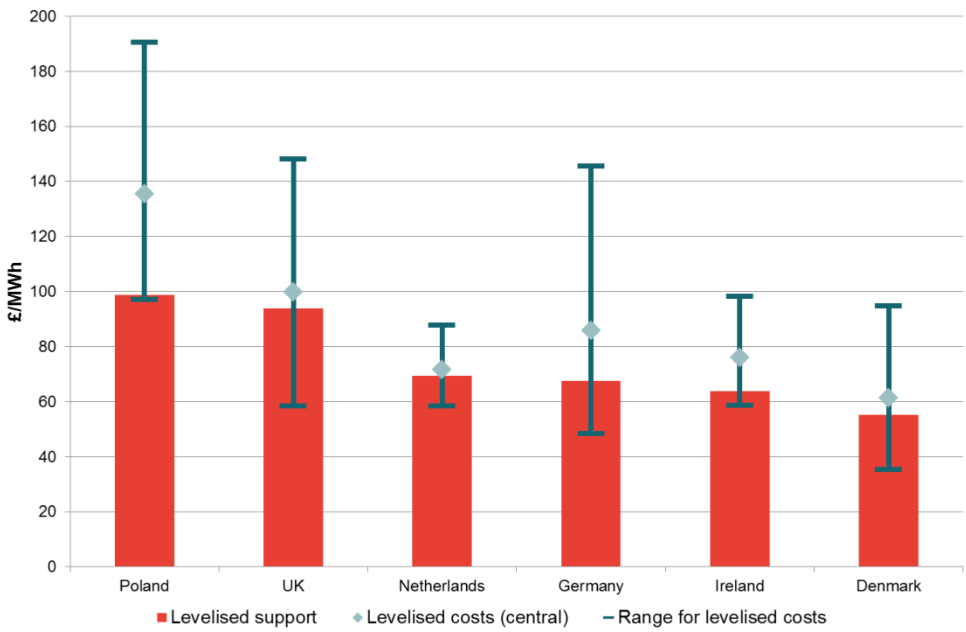
42 The calculation for this was described in the methodology section.

surveys of developers, and there may be reporting inconsistencies (particularly around how capital costs are disaggregated). Second, central estimates of costs mask high variability of costs *within* countries. For example, load factors can vary substantially depending on location while the choice of turbine technology can result in different capital costs, operating costs and load factors. Therefore it is important to consider the range of levelised costs.

### Comparing support levels to costs

Figure 16 shows how the range and central estimates of levelised costs compared to levelised support levels for new plant in 2011.

**Figure 16.** Levelised support levels and levelised costs for large-scale wind (£/MWh, based on mkt exchange rates)




Source: Data from various sources, analysis by Frontier Economics. Note these cost ranges do not reflect a supply curve for onshore wind. Rather they simply show the high and low estimates we have for these countries. We use a range of values for all of these parameters to provide sensitivities around a central levelised cost estimate. Where available, these ranges were based on the range of parameter values published. Where only a central estimate was available, we used sensitivities of +/- 10% of the central value. The case study sections detail these parameter assumptions.

It can be seen that in general support levels are higher where levelised costs are higher. This suggests that levelised costs have a strong influence on the differences in support levels seen across countries.

We note that central levelised cost estimates are mostly above levelised support levels. This may reflect the nature of the data which is often reliant on surveys. In most countries there was significant deployment in 2011 which suggests investment is viable for a large number of sites and projects.

## Explaining differences in support levels

### *Explaining cost differences*

Table 7 shows a comparison of our estimates of central levelised costs and their main components in 2011. We stress there are large sensitivities around these numbers as illustrated in Figure 16.

**Table 7.** Central levelised cost estimates for large-scale wind (2011 prices, market exchange rates)

| | UK | Denmark | Germany | Ireland | Netherlands | Poland |
|---|---|---|---|---|---|---|
| Capital costs (£m/MW) | 1.59 | 1.18 | 1.20 | 1.56 | 1.17 | 1.26 |
| Operating costs (£000/MW/year) | 50.2 | 41.2 | 41.4 | 41.2 | 45.5 | 126.4 |
| Costs of capital (pre-tax, real WACC) | 9.6% | 7.5% | 5.8% | 8.0% | 6.3% | 9.6% |
| Average load factor (new plant) | 29% | 31% | 20% | 32% | 25% | 24% |
| **Levelised cost (£/MWh)** | **100** | **61** | **86** | **76** | **72** | **135** |

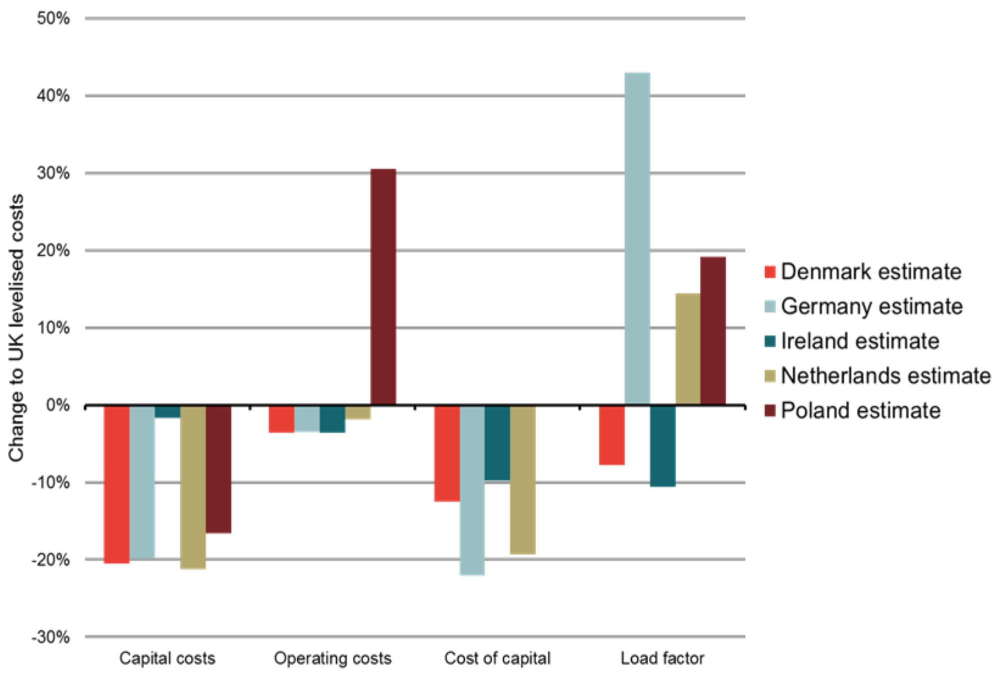
Source: Data from various sources (see country case studies), analysis by Frontier Economics

Remark: There is a high level of uncertainty and variability around these estimates.

To summarise the drivers of levelised cost differences, Figure 17 shows how UK levelised costs would be impacted if cost estimates from other countries were applied. In each case we take the central assumptions from the UK and apply the estimates for different countries for a specific parameter (e.g. capital costs) to see how this affects levelised costs. For example, for capital costs we hold all other assumptions fixed and show how the UK levelised costs would be affected if the capital costs from other countries were applied.

The figure shows that higher estimated capital costs and costs of capital are the main drivers of the higher estimated levelised costs in the UK.

**Figure 17**. Changes to UK levelised costs from applying individual levelised cost parameters from other countries




Source: Data from various sources, analysis by Frontier Economics

While there are major uncertainties around cost estimates and their breakdown across countries, we can make some observations about what may be driving the differences in the components of levelised costs.

- **Capital costs.** In our central case, which is based on the figures used for the RO banding review, the total capital costs in the UK are higher than all other case study countries at £1.59m/MW (although the differential to Ireland is relatively small). Compared to Denmark, Germany, the Netherlands and Poland, capital cost estimates are around £0.3-0.4m/MW higher in our central case, which translates into around £15 - 20/MWh in terms of levelised costs.

  Looking at the breakdowns of capital costs provides some insight into what may be driving higher capital costs. We discuss these in turn, dealing with the largest components of capital costs first.

  - Turbine costs. The available evidence suggests that the price developers pay for turbines is not the main factor in explaining the higher capital costs in the UK compared to the other case study countries.

    The capital costs attributable to the turbines in the UK were estimated to be just over £1m/MW in 2011 in our central case (around 66% of total capex), based on the costs provided by ARUP in their assessment for the banding review[43]. Based on analysis of limited data on capital cost breakdowns in other countries, turbine costs in 2011 appear to have been slightly lower in the other case study countries - of the order of £0.05-0.10m/MW. However, these differences may not be material given the uncertainties and potential inconsistencies in the data and the impact of exchange rate movements[44]. Anecdotal discussions with industry experts suggest that turbine prices in the UK are in line with those in continental Europe. For these reasons, we do not judge that turbine prices are a major factor in explaining higher capital costs in the UK.

- Construction, infrastructure and foundation costs. Based on our analysis of the breakdown of capital costs provided by ARUP, costs for construction, infrastructure and foundation in the UK were estimated to represent roughly £0.4m/MW of capital costs in the central case. These appear higher than other countries where quoted costs range between £0.1m/MW and £0.3m/MW. However, we again stress that breakdowns of data are not available on a completely consistent basis across countries.

  Suggested reasons for higher construction costs in the UK include the geological properties of the sites (e.g. soft soil in some areas) and the accessibility of sites. Higher general costs of construction in the UK have also been cited as a potential reason. However the evidence is mixed here with some other case study countries having higher estimated general construction costs[45]. We also note that another study by Mott Macdonald in 2011 suggests lower costs for construction, infrastructure and foundation in the UK[46].

- Connection costs. In the UK grid connection costs are estimated to represent £0.08m/MW of capital costs (5% of the total) on average in

43 ARUP (2012) *Review of generation costs and deployment potential of renewable electricity technologies in the UK.*

44 Turbines are purchased in Euros and therefore the relative strength of the pound can affect costs. In 2011 the pound was slightly weak, with a market exchange rate of 1.15 Euro/£ compared to a PPP rate between Germany and the UK of 1.18 Euro/£ (i.e. around 2% to 3% below 'fair' value).

45 For example in a survey by EC Harris general construction costs in the central case are estimated to be 47% higher in Denmark and 12% higher in Germany compared to the UK but 3% lower in Netherlands and 36% lower in Poland (EC Harris, 2012, *International Construction Cost Report*. A survey by Turner and Townsend estimated concrete costs as being over 25% higher in Germany compared to the UK but over 35% lower in Ireland - Turner & Townsend (2012) *International Construction Cost Survey 2012).*

46 Mott MacDonald (2011), *Costs of low-carbon generation technologies.*

our central case[47]. Although some countries, such as Denmark, appear to have slightly lower average connection costs than this (with the transmission operator taking a higher proportion of costs) they do not appear to be a major factor in explaining differences in support levels. We note however that grid connection costs vary widely within and across countries and the above only reflects averaged estimates.

- Development costs. Based on the limited available data it appears unlikely that development costs are a major reason for the higher estimates for capital costs in the UK. In the UK development costs are estimated to represent around £0.05m/MW on average (3% of total capital costs)[48] in our central case. The available data for other countries is limited on the proportion of capital costs specifically attributable to development with the exception of Poland and Ireland where estimated costs are slightly higher. A report in 2010 by EWEA found that costs associated with planning and permitting represented 2.9% of capital costs on average in the EU[49].

In summary, it is unclear exactly what is driving the higher estimated capital costs in the UK. Higher construction, infrastructure and foundation costs appear to be the most important factor, based on the estimates used for the banding review. Small differences in connection and turbines costs may have a minor influence.

- **Operating costs**. Operating costs in the UK in 2011 are estimated to have been at least £5,000 - 10,000/MW/year higher than in all countries other than Poland in our central case[50].

  This can largely be explained by the UK transmission charging regime. Onshore wind farms in the UK typically pay transmission charges of £10,000/MW/year (with sites in the North of Scotland paying double this), In contrast, in Germany, Netherlands and Denmark transmission charges are very low or zero as charges are weighted heavily towards demand rather than generation[51]. In terms of levelised costs, we estimate that transmission

---

47 Based on ARUP (2012) *Review of generation costs and deployment potential of renewable electricity technologies in the UK*. A report for EWEA in 2010 found that grid connection costs across the EU represented 5.13% of total capital costs on average. EWEA (2010), *Administrative and grid access barriers to wind power*.

48 ARUP (2012) *Review of generation costs and deployment potential of renewable electricity technologies in the UK*.

49 EWEA (2010), *Administrative and grid access barriers to wind power*.

50 Note UK operating costs do not include rent which, if included, would increase the difference above £10,000/MW/year.

51 In the UK 27% of transmission charges are levied on generation and are locational whereas the shares for Denmark, Germany and the Netherlands are 3%, 0% and 0% respectively. ENTSO-e (2012), *ENTSO-E Overview of transmission tariffs in Europe: Synthesis 2011*.

charges represent around £4/MWh additional costs in the UK compared to Denmark, Germany and the Netherlands (the difference between UK and Ireland is about half this given estimated charges of around £4000/MW/year in Ireland).

As regards other explanations for operating cost differences, some studies observe that maintenance costs are linked to the maturity of the market and the level of experience with onshore wind[52]. Operating costs in Poland are very high which may be explained by (i) the presence of a relatively high property tax and (ii) the immaturity of the market for O&M services.

- **Load factors**. The average load factors for new plant are a major driver of differences in levelised costs but this is not an explanation for higher levelised costs in the UK. At 29%, the estimated average load factor for new plant in the UK compares well to Germany (20%), Netherlands (25%) and Poland (25%). The difference between the UK level of 29% and the higher levels in Denmark (31%) and Ireland (33%) are worth £7/MWh and £12/MWh respectively in terms of levelised costs.

- **Costs of capital**. In the UK the central WACC[53] assumed for the government response to the RO Banding review of 9.6% (pre-tax, real) is higher than those cited in most other countries which are typically in the range 6% to 8% (with the exception of Poland). Each 100 bps drop in WACC, at UK cost levels, reduces levelised costs by around £5/MWh.

  Some of the difference between the UK and countries operating under a FiT or FiT (CfD) scheme (Germany, Ireland and the Netherlands) can be explained by the nature of the support scheme. Under FiT and FiT (CfD) schemes generators do not face price risks. This has been estimated by DECC to be worth around 50 bps (0.5 percentage points) in reduced WACC[54]. WACCs quoted in Denmark are also lower than the UK despite generators facing price and balancing risk in both countries. However, there may be more risk around the subsidy level under the RO compared to the PFiT where tariff levels are grandfathered in nominal terms.

52 IRENA (2012), *Renewable Energy Technologies: Costs Analysis Series: Wind Power.*

53 Weighted average cost of capital (WACC). This is rate on average that an investment must pay back to its debt and equity holders, taking into account the relative shares of debt and equity. The WACC represents the minimum return that an investment must earn to cover its financing costs and is used to discount future cashflows.

54 Other estimates of this value are available. A report by Redpoint suggested the removal of price risk under a FiT was worth 30 bps (0.3%) for onshore wind - Redpoint, 2010, *Electricity Market Reform: Analysis of Policy Options*. A report by CEPA suggests the value is between 0 and 40 bps (0% to 0.4%) – CEPA, 2011, *Note of Impacts of the FiT CfD Support Package on Costs and Availability of Capital.*

Perceived development risk is another reason given by investors for the higher WACCs cited in the UK, although this is unlikely to explain a large amount of the difference given the small amount of capital employed at the development stage (around 3% of total capital costs). The evidence on whether development costs and risks are higher in the UK is mixed (see section 4.4).

In Germany the presence of state-backed financing has been important in reducing financing costs. Loans from KfW (a state-guaranteed bank), which are offered at favourable, below-market rates have helped finance over 80% of installed wind in Germany.

There are two main conclusions from this section. First, countries with higher estimated levelised costs also have higher support levels. Second, the higher costs seen in the UK are being driven mainly by higher estimated capital costs and financing costs.

### *How the support mechanism impacts on support levels and costs*

There are a number of ways in which the design of the support schemes may be influencing support levels and deployment costs.

- **Risk transfers and "hold-up" costs**. Wind generators are exposed to different risks according to the type of scheme and market arrangement in each country. In particular, under FiT schemes in Germany, Ireland and the Netherlands, they are not exposed to price risks. As discussed above, these are estimated to reduce the cost of capital by around 50 bps. In addition, in Germany generators are also not exposed to balancing risks or costs, providing a further benefit.

  However, it should be noted that these transfers are not costless. Price and balancing risks in other parts of the market may increase while incentives for efficient dispatch and wind forecasting can be distorted[55].

  The way in which the subsidy is paid can also influence the efficiency of the scheme from a generator perspective. In Germany and Denmark generators receive the subsidy payment directly whereas in the UK, Poland and Ireland payment it is received via suppliers. This may increase transaction costs. The level of these costs is difficult to estimate as the level of 'pass-through' of subsidy from suppliers to generators also reflects risks (e.g. price, balancing) that the supplier may be taking on the generators behalf[56].

---

55 In Germany this is addressed through the TSO taking responsibility for wind forecasting and dispatch.

56 For example it has been suggested in the UK that independent wind developers receive around 90% of the Renewables Obligation Certificate (ROC) value, 90% of the LEC value and 87% of the

- **Differentiation between renewable technologies**. With the exception of Poland, all case study countries differentiate support levels across renewable technologies. This helps ensure that the cheaper technologies (including onshore wind and biomass co-firing) do not earn excess returns. However, at the same time incentives to deploy the cheapest technologies first are weakened. Poland is now proposing to move to a technology banding system as well, with onshore set to receive a reduced support level as a consequence.

- **Differentiation between windfarms**. As shown in Figure 16 the levelised costs vary substantially, particularly in relation to site wind yield. In Germany and Denmark, because the support duration is linked to load factors, higher yielding sites with lower levelised costs receive less support. Again this helps to reduce excess rents and makes lower yielding sites more viable. However, the drawback is that the incentive to exploit the best sites is reduced. Moreover, when support is based on full-load hours, developers may have incentives to install larger machines with lower load factors[57].

- **Stability of support**. Stability of the available subsidies is clearly important. Germany (and to a lesser extent UK, Ireland and Poland) have achieved relatively consistent levels of wind deployment with comparatively stable and well-signalled support levels. In the Netherlands and Denmark deployment has been disrupted in recent years as the support mechanism changed and as support levels dropped respectively. The case study annexes show how support levels and deployment of onshore wind have varied over time.

As demonstrated above, there are many trade-offs in the design of support schemes. Therefore it is difficult to say definitively which design is most effective.

## 4.4 Other factors

### *Other support measures*

In the section we cover other measures that help support large-scale onshore wind and as consequence may help lower the support required from the main scheme. The most notable support measures are as follows.

---

average wholesale price from purchasers of their generation. Reasons for this include (i) that purchasers of generation may be taking risks around wholesale prices, ROC prices and balancing (ii) the average price that wind captures may be below the average wholesale price and (iii) there are administration costs associated with handling ROCs and trading generation.

57 http://www.alice.uni-oldenburg.de/download/denmark_080511.pdf

- **Investment tax incentives**. The Netherlands and Ireland use investment tax incentives for onshore wind. In Ireland companies can offset 100% of investment in wind turbines against corporation tax liabilities in year one. In the Netherlands 41.5% of investment can be written off against tax in year one. Both of these help to improve cashflow in the early years aiding financing (although the value will vary depending on the profitability of the firm).

- **Financing support and loan guarantees**. Germany, Poland and Denmark all use financing support and loan guarantees to help finance projects. In Germany this is a major factor with the state-run bank, KfW, helping to finance of 80% of installed wind capacity in Germany at low interest rates. In Poland many wind farms are part-financed by European structural funds and institutions (e.g. EBRD, EIB) as well as through 'soft' loans from national funds. Loan guarantees are provided in Denmark, although these are limited to financing of development spend for community-scale projects.

- **R&D**. All of the case study countries have some form of R&D program covering wind. Much of this funding is focused on resources assessment, grid integration issues and new turbine technologies. However, none of these appear to be significant, perhaps reflecting the relative maturity of onshore wind technology. In Denmark, past R&D funding and early deployment support appears to have played a significant in developing domestic supply chains – this may in turn have helped reduce costs.

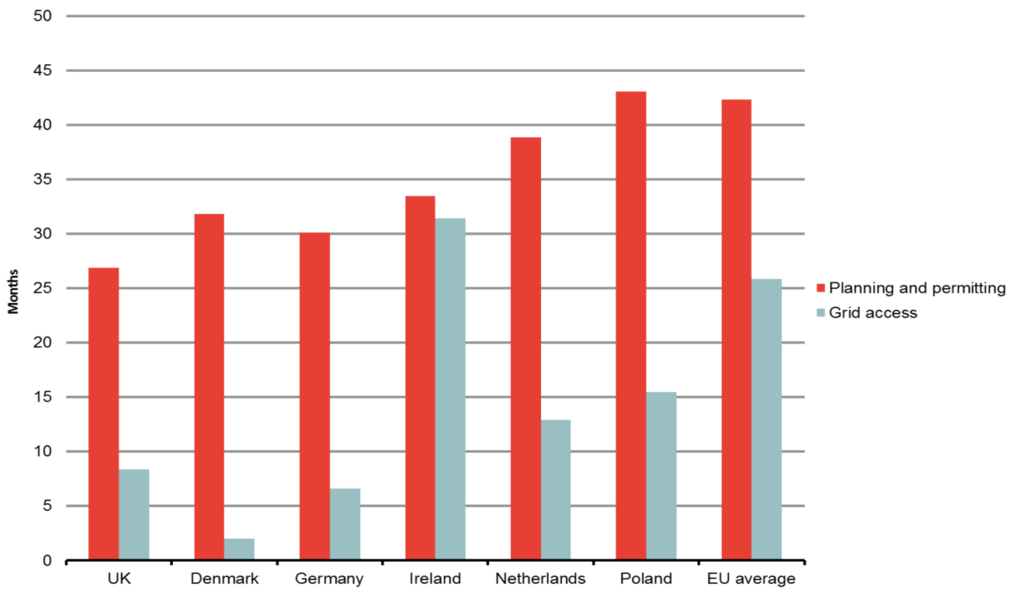
The above schemes, particularly financing support, are for some projects likely to be a significant component of support. However, given the diversity of these schemes and the fact that their eligibility and value can be highly project or firm specific, it is not possible to quantify the average value of these.

### *Grid access, planning and community benefits*

This section looks at how grid access and planning barriers to deployment compare across countries. These factors can both add risk and cost to projects and are, to some extent, reflected in the levelised costs estimates already discussed in this section.

Based on a survey for EWEA in 2010, the UK appears to have compared reasonably well with other case study countries in terms of planning and grid access lead times (see Figure 18). This suggests risks associated with delays for developers in the UK may not be any greater than other case study countries especially as lead times have fallen in recent years. The rates for successful consent may also have an impact but consistent data across countries is not available. In the UK approval rates have been above 50% in recent years[58].

**Figure 18.** Average planning and grid access lead times as of 2010 (months)




Source: EWEA (2010), *Administrative and grid access barriers to wind power.* Note some of the sample sizes in this study were relatively small.

In the UK the provision of community benefits is becoming increasingly important in projects. At present these typically range between £1000/MW/year to £5000/MW/year[59]. These costs are not factored into the estimated of levelised costs earlier. This high end of this range would add around £2/MWh to levelised costs.

58 For projects above 50 MW, consent rates were 86% in 2009/10 and 91% in 2011/12. For projects below 50 MW, where the planning decision is made at a local level, consent rates were lower at 63% in 2009/10 and 59% in 2011/12. The average consented capacity was 15.5 MW in 2011/12. Approval rates are highest in Scotland at 70% in 2011/12 which is also where the wind resource is highes - RenewableUK (2012), *Wind Energy in the UK: State of the Industry Report 2012.*

59 Oxera (2012), *Outlook for onshore wind; analysis to inform DECC's Call for Evidence: Onshore Wind - Costs*

# 5 Conclusions

This study shows that there are large differences in support levels for onshore wind across countries.

UK support levels are in the top half of countries and regions examined. The absolute support for onshore wind in the UK in 2011 was around £95/MWh including the value of the wholesale revenues, Renewables Obligation Certificates (ROCs) and CCL exemption certificates (LECs). The average support level (giving each country equal weight) was £82/MWh on a PPP basis and £77/MWh on a market exchange rate basis.

In general support levels were lowest in North America while Denmark and Sweden saw the lowest support levels in Europe. Depending on the measure used for comparison the UK has between the 7$^{th}$ and 9$^{th}$ highest support level. In terms of duration of support provided from the main support scheme, the UK sits at the top of the range of 9 to 20 years.

To explain the differences in support we looked in detail at the UK and five other EU countries (Denmark, Germany, Ireland, the Netherlands and Poland). Within this group the UK support levels were again above average. This can be explained mainly by higher estimated capital costs and financing costs in the UK.

Other factors, such as the nature of the support scheme (e.g. how it allocates risks and differentiates support), other support measures (e.g. financing support) and the level of political support for onshore wind may also cumulatively help explain the lower support levels seen in countries such as Germany and Denmark.

# 6 References

The following is a list of the main references used in the supporting analysis for this report. References quoted in the main document are additional to these.

AESO, 2013, Market and System Reporting. Available at: http://www.aeso.ca/market/8856.html Accessed (05/02/13)

Alberta Tax and Revenue Administration, 2010, Alberta Corporate Tax Act Information Circular. Available at: http://www.finance.alberta.ca/publications/tax_rebates/corporate/ct17.html (Accessed 04/02/2013)

APER, 2013, Observatoire éolien. Available at: http://www.apere.org/index/node/135 (Accessed 02/02/13)

Argus, 2012, Argus Power Europe, Volume XII, February 1st 2012

Australian Clean Energy Regulator, 2013, The Large-scale Renewable Energy Target. Available at: http://ret.cleanenergyregulator.gov.au/About-the-Schemes/Large-scale-Renewable-Energy-Target--LRET-/about-lret (Accessed 25/01/13)

CCEE, 2013, Preços médios. Available at: http://www.ccee.org.br/portal/faces/pages_publico/o-que-fazemos/produtos/precos/ (Accessed 05/02/13)

CDE, 2012, Parc éolien français. Available at: http://www.connaissancedesenergies.org/fiche-pedagogique/parc-eolien-francais (Accessed 07/02/13)

Centraal Bureau voor de Statistiek, 2012, Hernieuwbare energie in Nederland 2011.

CENWEA, 2013, Wind by the Numbers: Economic Benefits of Wind Energy

CER, 2012, Quarterly SEM price report: Quarter 4 2012.

CERC, 2012, Report on Short-Term Power Market in India 2011-12

Chinese Wind Energy Association, 2013. Available at: http://www.cwea.org.cn/policy/dispaly_info.asp?cid=27

CRA, 2013, Corporation Tax Rates. Available at: http://www.cra-arc.gc.ca/tx/bsnss/tpcs/crprtns/rts-eng.html (Accessed 04/02/13)

CWAPE, 2013, Statistiques. Available at: http://www.cwape.be/?dir=3.4.08 (Accessed 01/02/13)

Danish Energy Agency, 2012, Annual Energy Statistics 2011.

DCENR, 2013, REFIT. Available at: http://www.dcenr.gov.ie/Energy/Sustainable+and+Renewable+Energy+Division/REFIT.htm (Accessed 10/02/13)

DECC, 2012, Digest of UK Energy Statistics.

DEWI, 2012, Windenergienutzung in Deutschland. Available at: http://www.dewi.de/dewi/index.php?id=47 (Accessed 31/01/13)

DG Energy, 2011, Integration of electricity from renewables to the electricity market- National report: Poland.

e-control, 2011, Bundesgesetzlbatt fur die Republik Öserreich

e-control, 2013, Ökostrom - Einspeisemengen und Vergütungen, Available at: http://www.e-control.at/portal/page/portal/medienbibliothek/oeko-energie/dokumente/pdfs/Oekomengen%204Q2011_%20Stand%2012_2012.pdf (Accessed 26/01/13)

EEG, 2012, EEG Jahresabrechnung 2011. Available at: http://www.eeg-kwk.net/de/file/EEG-Jahresabrechnung_2011.pdf (Accessed 31/01/13)

e-ROC, 2013, ROC Auction Prices. Available at: http://www.e-roc.co.uk/trackrecord.html (Accessed 01/02/13)

ERCOT, 2012, 2011 Annual Report on Texas REC Trading Program

EREC, 2009, Portugal: Renewable Energy Policy Review

EWEA, 2012, Wind in Power 2011 European Statistics

EWEA, 2013, Eastern Winds: Emerging European wind power markets

AEE (2012), Eolica 2012:

GME, 2012, Annual Report 2011.

GWEC, 2011, Global Wind Report.

GWEC, 2011, Indian Wind Energy Outlook 2011

IEA Wind, 2012, IEA Wind Annual Report for 2011.

IEA, 2011, Technology Roadmaps: China Wind Energy Development Roadmap 2050.

IESO, 2013, Wind Power in Ontario

Industry Canada, 2013, Canada Small Business Financing Program. Available at: http://www.ic.gc.ca/eic/site/csbfp-pfpec.nsf/eng/h_la02855.html (Accessed 05/02/13)

JEPX, 2013, Japan Electricity Power Exchange. Available at: http://www.jepx.org/ (Accessed 08/02/13)

KMPG, 2011, Tax and Incentives for Renewable Energy

Legal Information Institute, 2013, 26 USC § 45 - Electricity produced from certain renewable resources. Available at: http://www.law.cornell.edu/uscode/text/26/45 (Accessed 01/02/2013)

Maine Public Utilities Commission, 2010, Report on New Renewable Resource Portfolio Requirement

METI, 2012, Feed-in Tariff Scheme in Japan 2012.

Ministerie van Economische Zaken, 2012, Annual Report 2011

Ministerio de Minas e Energia, 2009, Programa de Incentivo as Fontes Alternativas de Energia Electrica

Natural Resources Canada, 2011, ecoENERGY for Renewable Power Available at: http://www.nrcan.gc.ca/ecoaction/6444 (Accessed 05/02/13)

OEMAG, 2013, Aktive Verträge und installierte Leistung, Available at: http://www.oem-ag.at/de/oekostrom/statistik/inst_leistung (Accessed 26/01/2013)

Ofgem, 2012, Feed-in Tariff Annual Report 2011-12

Ontario Financing Authority, 2013, Aboriginal Loan Guarantee Program. Available at: http://www.ofina.on.ca/algp/program/overview.htm (Accessed 04/02/2013)

Ontario Power Authority, 2013, Feed-in Tariff Program

PWC, 2012, Turkey's Renewable Energy Sector from a Global Perspective

RES Legal, 2013, Legal Sources on Renewable Energy. Available at: http://www.res-legal.eu/compare-support-schemes/ Accessed (01/02/13)

RTE, 2012, Statistiques de l'énergie électrique en France 2011

SEA, 2012, Energy in Sweden 2012

SEA, 2012, The electricity certificate system in 2012

Statistics Canada, 2011, Spending on research and development

TWEA, 2012, Wind Business in Turkey: An outlook for investors

The Wind Power, 2012, Capacités de production. Available at: http://www.thewindpower.net/country_fr_21_belgique.php (Accessed 02/02/13)

US Department of Energy, 2013, Database of State Incentives for Renewables and Efficiency

World Bank, 2012, Renewable Energy Auctions – the Brazilian Experience.

Bloomberg, Ventyx and Energate data were also used for wholesale price statistics.

# References

# Annexe 1: UK Case study

## Summary

Since 2002 the UK has used a quota scheme, the Renewables Obligation (RO), to support large-scale onshore wind deployment. The design of the RO has evolved over time with the introduction of technology differentiation and a price stabilisation measure (headroom) in 2009. From 2014 a new FiT (CfD) scheme will be available.

The current levels of support for onshore wind in the UK are well-matched to estimated levelised costs. In recent years the levels of wind deployment have also been relatively consistent, ranging from 554 MW/year to 737 MW/year in the period between 2008 and 2011.

The costs of deployment in the UK are relatively high which is largely explained by high estimated capital costs and costs of capital.

## Context

The main drivers behind subsidies for renewables in the UK are the need to meet the EU renewables target and carbon emissions reduction targets (where the UK has self-imposed targets).

Under the EU carbon target the UK must source 15% of total energy from renewable energy by 2020. As one of the most cost-effective and scalable renewable[60] technologies in the UK, onshore wind is seen as a key part of meeting these targets. The Government's ambition, set out in the Renewables Roadmap, is to reach 10--13 GW of onshore wind capacity by 2020[61].

At the end of 2011 there was 4,650 MW of onshore wind installed in the UK. The generation from this (10 TWh) contributed 3% of UK electricity supply in 2011[62]. During 2011 over 600 MW of onshore wind was installed[63] representing investment of almost £1bn. There is currently a large pipeline of onshore wind projects with around 6 GW with planning consent and a further 7 GW in

60 ARUP have estimated that, "if deployment constraints are relaxed" there is potential for an additional 10-14 GW of installed capacity by 2020 and a further 15-24 GW by 2030. ARUP (2011), *Review of the generation costs and deployment potential of renewable electricity technologies in the UK*

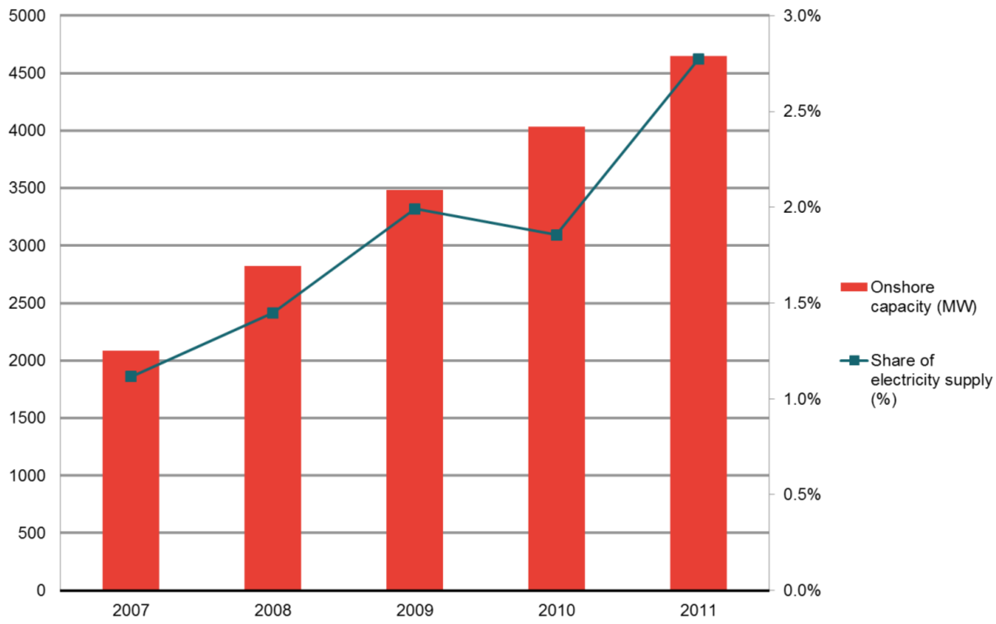
61 DECC (2011), *Renewable Energy Roadmap.*

62 DECC (2012), *Onshore Wind – Call for Evidence.*

63 DECC (2012), *Digest of UK Energy Statistics.*

planning[64]. Over half of this development is expected to be in Scotland where wind speeds and land availability are greater.

**Figure 19.** Installed onshore wind capacity and percentage of electricity generation met from onshore wind



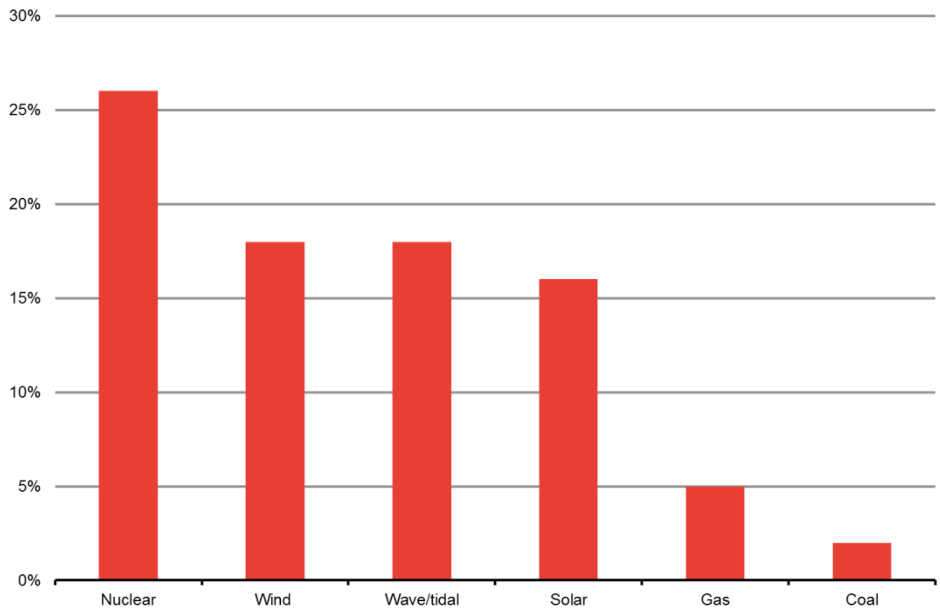

Source: Frontier calculations based on DECC (2012), *Digest of UK Energy Statistics*. Tables 6.4 and 5.1.

There is mixed evidence on public support for wind power in the UK. A recent survey by YouGov found it ranked second in a list of preferred technologies for meeting Britain's energy needs (see Figure 20). Meanwhile, 56% of people surveyed felt that the government was right to spend money encouraging wind energy, compared to 26% who thought it was wrong[65]. In some areas local opposition to wind farm development can be strong.

64 RenewableUK (2012), *Wind Energy in the UK: State of the Industry Report 2012.*

65 YouGov (2013), *Poll commissioned for the Sunday Times.*

**Figure 20.** Response to the question: "Thinking about providing for Britain's future energy generation needs, which of the following do you support the most?"




Source: YouGov (2013), *Poll commissioned for the Sunday Times*

## Main support scheme(s)

This section describes the support available for large-scale wind under the Renewables Obligation (RO) and how this has developed over time.

### *Current situation and support scheme design*

The main support scheme in the UK for large-scale wind is the Renewables Obligation (RO). This is an obligation on electricity suppliers to source a proportion of their electricity supplied from renewable sources. Under the RO onshore wind farms receive revenues from sale of Renewables Obligation Certificates (ROCs) in addition to wholesale market revenues.

In 2011, the absolute support for onshore wind operating under the RO was around £94/MWh[66]. This was composed of £46/MWh from wholesale market revenues (which factors in an estimate that wind farms captured around 97% of

66 Note this number factors in the market value of wind whereas in the high level international comparisons a 'baseload' market price was used for consistency. This gave a number of £95/MWh.

the average APX spot price in 2011[67]), £42/MWh from ROCs and £5/MWh from Levy Exemption Certificates (LECs).

Wind farms are eligible for 20 years of support under the RO. The ROC price is determined by the supply and demand for ROCs, with the former determined by the volume of renewable generation and the latter by the size of the obligation (set each year on an increasing trajectory). Two additional measures limit the volatility in ROC prices.

- A **buyout price** (£38.68 per ROC in 2011/12 and indexed to inflation) is paid out by suppliers for any shortfall between the ROCs owned by supplier and their obligation (with the buyout revenues 'recycled' to suppliers who have presented ROCs to Ofgem). This works to limit the extent to which the ROC price rises.

- In 2009 a mechanism called '**headroom**' was introduced to ensure the stability of the market for ROCs and to provide increased investor confidence. 'Headroom' works by ensuring the obligation set for a given year is at least 10% above expected generation for that year.

The RO began as a technology neutral scheme with all renewables generation types receiving one ROC for each MWh of generation. However, in 2009 a system of banding was introduced to reflect different costs and potential for technologies. For example, in 2009 the rate of support for Offshore Wind increased to one and a half ROCs, and subsequently to two ROCs per MWh for projects accrediting between 2010 and 2014 following a banding review. Onshore wind has received one ROC per MWh until this year. This year (2013) the ROC multiple has been reduced from 1 to 0.9 for onshore wind.

One important impact of banding is it reduces the potential for cheaper technologies to earn excess rents (e.g. where the ROC price is set by the more expensive technologies at the margin).

### *History of main support scheme(s) and deployment*

The RO has been the main driver of renewable generation and onshore wind deployment since it was introduced in 2002. In 2011, 34% of ROCs issued were made to onshore wind[68].

Prior to the RO, the main mechanism for supporting renewables and onshore wind was the Non-Fossil Fuel Obligation (NFFO) which consisted of renewable

---

67 Frontier analysis using half-hourly wind and price data (System Buy Price) from Elexon (spot prices closely track this value). Note in part one we assumed wind farms captured 100% of average baseload price for consistency with the approach taken for other countries.

68 Ofgem (2013), *Renewables Obligation: Annual Report 2011-12.*

projects competitively tendering for fixed price Power Purchase Agreements (PPAs). The scheme began in 1990 but had limited success, delivering only 821 MW of renewable capacity in just over a decade.

In real terms (2011 prices) the absolute support available for onshore wind under the RO has ranged between £84/MWh and £136/MWh since the scheme began in 2002 with an average value of £99/MWh. There has been a general trend towards more support coming from market revenues and less revenues from the RO over time (although there is some volatility within this trend).

**Figure 21.** Development of absolute support for onshore wind under the RO (2011 prices)


Sources: Wind deployment data provided by Renewable UK. ROC values from DECC. The market value of wind is set to 97% of the average annual spot price (APX). This percentage is based on analysis of half-hourly prices and wind generation data from 2011 to find a "wind-weighted" average price. All prices are converted into real terms using CPI index.

Since 2008 the deployment rate for wind has ranged between 554 MW/year and 737 MW/year[69]. The top of this range occurred in 2008 when absolute support levels were also at their highest as a result of high electricity prices.

The majority of wind farms built recently (in terms of capacity) have been above 20 MW. In 2011/12 wind farms above 20 MW represented 81% of new build

[69] Statistics provided by Renewable UK.

compared to windfarms between 5 MW and 20 MW (15%) and below 5 MW represented only (4%)[70].

In 2010 a Feed-in Tariff (FiT) was introduced for small-scale renewables in addition to the RO which was targeted at large-scale renewables. Under the FiTs scheme electricity suppliers must provide a fixed payment for generation and generators also receive an additional payment for electricity they export (i.e. generation in excess of their onsite consumption). Only wind farms under 5 MW qualify for the FiT. Compared to the RO, onshore wind deployment under the FiT has been low with around 55 MW of capacity installed by March 2012.

For new large-scale onshore wind a new mechanism (Contracts for Differences) will be available from 2014. This mechanism aims to promote deployment by reducing long-term price risks facing renewables projects. The RO will be open to new projects or additional generation added to existing accredited schemes until April 2017.

## Costs of wind deployment

The following provides cost calculations for onshore wind in the UK for windfarms over 5 MW (over 95% of wind capacity built in 2011/12 exceeded this size).

### *Capital costs*

Onshore wind capital costs in the UK were recently reviewed as part of the RO banding review. These are shown in Table 8 in 2011 prices. There is evidence suggesting that capital costs will fall by 3.6% from these levels by 2016[71].

---

70 RenewableUK (2012), *Wind Energy in the UK: State of the Industry Report 2012.*

71 DECC (2012), *Onshore Wind – Call for Evidence: Part B – Costs.*

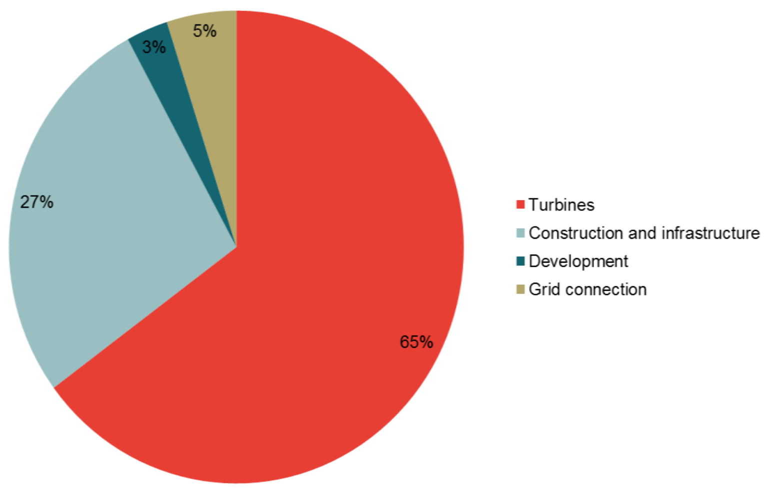
**Table 8.** Capital cost estimates for large scale onshore wind in the UK, 2011

| | £m/MW |
|---|---|
| **Low** | 1.2 |
| **Median** | 1.6 |
| **High** | 2.0 |

Source: Based on DECC (2012), *Government response to the consultation on proposals for the levels of banded support under the Renewables Obligation*. These are figures for project starting in 2012/13 converted into 2011 prices using the GDP deflator index.

The majority of capital costs are associated with the purchase of the turbines and construction. The breakdown of capital costs for the above estimates shown below in Figure 22.

**Figure 22.** Components of UK onshore wind capital costs




Source: Frontier analysis based evidence from from ARUP (2011), *Review of the generation costs and deployment potential of renewable electricity technologies in the UK*.

In making cross-country comparisons it is also useful note the manufacturers of turbines being deployed in the UK. RenewableUK estimate that Siemens, Vestas and RE power together represented over 75% of the onshore wind market by capacity in 2011. Siemens was the largest contributor, supplying 49% of turbine capacity[72].

### Operating costs

Operating costs include operations and maintenance (O&M) costs, insurance, and grid charges. Table 9 shows estimates of total operating costs based on those used for the banding review, converted into a 2011 price base.

These are composed of average fixed operating costs (£26,200/MW/year)[73], variable operating costs (£3/MWh)[74], insurance (£6,500/MW/year) and grid charges (£10,200/MW/year)[75]. These are converted into a single annual cost for comparison with other countries.

**Table 9.** Operating cost estimates for large scale onshore wind in the UK, 2011

| £'000/MW/year | £'000/MW/year |
|---|---|
| **Low** | 45 |
| **Median** | 50 |
| **High** | 55 |

Source: Central estimates are Frontier calculations based on DECC figures used in the banding review. These are 2012/13 figures converted into 2011 prices using the GDP deflator index. High and low values are +/-10% of central values.

### Cost of capital

The return on capital that investors in onshore wind require in the UK under the Renewables Obligation (RO) is determined by a number of risks including those around wholesale prices (including carbon prices), policy (including the ROC price), construction and technology performance.

The following cost of capital estimates for onshore wind in the UK are available:

- In its review of renewables' costs for DECC, ARUP uses a pre-tax real hurdle rate of 9.6% in their assessment of levelised costs[76].

---

72 RenewableUK (2012), *Wind Energy in the UK: State of the Industry Report 2012*

73 Note, in the DECC figures operating costs are stepped at £14,600/MW/year for years 1-5 and £34,300 for years 6+. We use a discounted average value for these to allow comparison with other countries (using a 9.6% discount rate).

74 We convert this into an annual cost using the central load factor of 28.6%.

75 In Great Britain transmission charges are locational and therefore this component of operating costs can be highly variable.

76 ARUP (2011), *Review of the generation costs and deployment potential of renewable electricity technologies in the UK*

- Oxera estimate a current pre-tax WACC for onshore wind of between 7% and 10%[77].

- CEPA estimate post-tax nominal costs of capital for onshore wind in the UK of between 8.4% and 9.0%. Converting this into post-tax real (assuming inflation of 2% and tax of 26%) provides a range of 9.4% to 10.1%[78].

We apply ARUP's estimated WACC of 9.6% in our central estimates of the levelised costs. For our high and low estimates of WACC we use 7% and 11% respectively.

### *Load factors*

Figure 23 shows average load factors for onshore wind in the UK in recent years. Between 2001 and 2011 the average load factor for onshore windfarms in the UK was 26%. In analysing current levelised costs we assume a load factor of 28.6% in the central case reflecting the higher load factors achieved by new wind turbines. This is consistent with the assumptions made by DECC for the banding review[79]. For low and high value we use 25.5% and 33.3% respectively which are the DECC estimates for load factors for new plant in 'England & Wales' and 'Northern Ireland'.

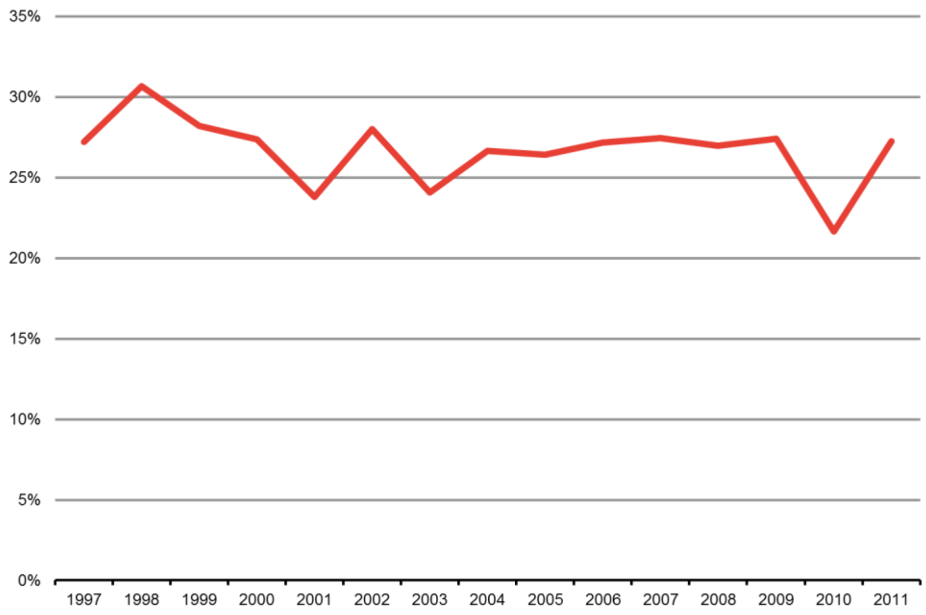
---

77 Oxera (2011), *Discount rates for low-carbon and renewable generation technologies*

78 CEPA (2011), *Note on impacts of the CfD support package on costs and availability of capital and on existing discounts in Power Purchase Agreements*

79 ARUP (2011), *Review of the generation costs and deployment potential of renewable electricity technologies in the UK*

**Figure 23.** Onshore wind average load factors in the UK




Source: DECC (2012), *Digest of UK Energy Statistics*, Table 6.5. Based on average beginning and end year capacity.

### *Levelised costs*

Capital costs and operating costs, as well as load factors, may vary across projects. To capture a wide range of projects, we calculate the levelised costs for onshore wind in the UK in 2011 based on three possible cost levels. The assumptions can be found in the table below.

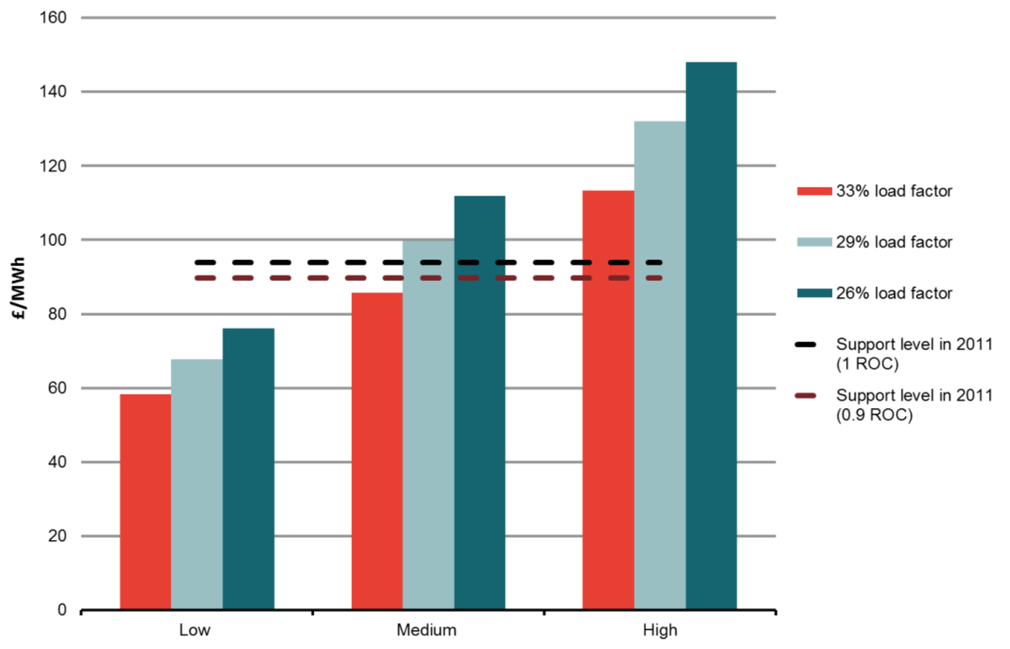
**Table 10.** Assumptions for calculation of levelised costs in the UK (2011 prices)

| Item | Low | Medium | High | Source/ remarks |
|---|---|---|---|---|
| **Capital costs [£m/MW]** | 1.2 | 1.6 | 2.0 | DECC |
| **Operating costs [£'000/MW/yr]** | 45 | 50 | 55 | DECC |
| **WACC (real, pre-tax)** | 7.0% | 9.6% | 11.0% | DECC, Oxera |
| **Years of operation** | 20 | 20 | 20 | |

Sources: See above

We calculate the levelised costs using three different load factors. The results are presented in Figure 24.

**Figure 24.** Levelised costs of large-scale onshore wind in the UK (2011 prices)




Source: Frontier

These estimates of levelised costs are sensitive to the assumptions made on capital costs, operating costs, cost of capital and load factors. To give a sense of this, the levelised costs of an onshore wind farm are affected in the following ways.

- Reducing the WACC by 100bps from 9.6% (pre-tax) to 8.6% (pre-tax) reduces levelised costs by £6/MWh (6%).
- Increasing capital costs by 10% increases levelised costs by £8/MWh (8%).
- Increasing operating costs by 10% increases levelised costs by £2/MWh (2%).
- Reducing the load factor from 29% to 24% increases levelised cost by £21/MWh (21%).

## Other factors influencing deployment

### *Other support measures*

The following summarises other support measures not factored into the estimates of levelised costs estimated above.

- **FiT for small-scale wind**. Small-scale wind (less than 5 MW) is eligible for the FiT introduced in 2010. This places an obligation on electricity suppliers to provide a fixed payment for the production of electricity by generators which varies by technology type and size.

  The FiT offers higher levels of support than under the RO, reflecting the higher costs of deployment at a smaller scale. The tariff rates vary by size of installation and in 2011/12 ranged from £379/MWh for projects less than 1.5kW to £49/MWh for plant above 1.5MW. All plant also receives an export tariff of £32/MWh on top of these figures for generation in excess of on-site consumption[80].

- **R&D**. Most of the wind R&D funding in the UK is currently focused towards offshore wind. The Renewable Energy Strategy[81] commits around £50m until 2015 aimed at developing innovation in areas like offshore wind, marine energy, waste and biomass. Much of the R&D funding is channelled through Research Councils. The Energy Programme for the Research Councils has invested £360m in general energy R&D between 2006 and 2011, including projects relevant to onshore wind. The EPSRC in 2006 established the SUPERGEN Wind Energy Technologies consortium which brings together seven university research groups and 19 industrial partners and has been researching area including wind turbine technology, aerodynamics, materials and reliability[82].

- **Financing support**. The UK does not currently offer loan guarantees for onshore wind projects. A Green Investment Bank has been established in the UK to aid financing of energy projects. However, this is expected to focus on technologies less mature than onshore wind such as offshore wind, CCS and marine energy.

---

80 Ofgem (2012), *Feed-in Tariff (FiT); Annual Report 2011-12.*

81 HM Government (2009) *The UK Renewable Energy Strategy.*

82 IEA Wind (2012), *Annual Report 2011.*

### Planning and community benefits

The ability for wind developers to gain planning consent for projects is seen as a constraint on wind deployment in the UK. There are two dimensions to this.

- **Time spent in planning**. The average decision time for onshore wind farms stands at 42 months for projects above 50 MW (determined at Ministerial level) and 15 months below 50 MW (determined at a local level). These decision times have reduced in recent years[83]. As shown earlier, there is some evidence that planning lead times in the UK compare well to other countries (see Section 4).

- **Approval rates**. For projects above 50 MW, consent rates were 86% in 2009/10 and 91% in 2011/12. For projects below 50 MW, where the planning decision is made at a local level, consent rates were lower at 63% in 2009/10 and 59% in 2011/12. The average consented capacity was 15.5 MW in 2011/12. Approval rates are highest in Scotland at 70% in 2011/12 which is also where the wind resource is highest[84].

Some wind developers have voluntarily introduced community benefit schemes to promote local support for onshore wind projects. Under a protocol coordinated by RenewableUK (the industry's main trade body), developers in England have committed to provide a minimum of £1,000 per MW of installed capacity per year, provided as a flexible package to host communities[85]. However, there is evidence that in some cases actual benefits paid can be around five times higher than this[86].

### Grid access

In the past getting a connection to the grid has been a major source of delay and risk for onshore wind developers in the UK, with long "queues" for connection developing.

However, major steps have been made to resolve this from a developer perspective with the implementation of the "connect and manage" regime for transmission access which began in 2009 and completed in 2011. Under this access regime, new generation is entitled to a connection date based on the time needed to complete a project's 'enabling works' (i.e. ahead of the completion of

83 RenewableUK (2012), *Wind Energy in the UK: State of the Industry Report 2012.*

84 RenewableUK (2012), *Wind Energy in the UK: State of the Industry Report 2012.*

85 RenewableUK (2011), *Onshore Wind – A community commitment.*

86 Oxera (2012), *Outlook for onshore wind; analysis to inform DECC's Call for Evidence: Onshore Wind – Costs.*

wider grid reinforcements)[87]. Under this regime, grid access is seen a less of a major constraint on development[88].

Even by 2010 the grid access lead time for wind in the UK was comparatively low at an average of 8 months compared to an EU average of 26 months[89].

87 Ofgem (2011), *First report from Ofgem on monitoring the 'Connect and Manage' electricity grid access regime*

88 Although, from a system perspective there a still wider issues with managing constraints if wind deployment proceeds ahead of the necessary grid reinforcements.

89 EWEA (2010), *Administrative and grid access barriers to wind power*

# Annexe 2: Denmark case study


## Summary

Denmark has a long history of support for onshore wind. Since 2005 the main support has been in the form of a PFiT scheme. Despite a period of stagnation in deployment between 2003 and 2007 when support levels fell, Denmark has achieved the highest onshore wind penetrations in the world, with 18% of demand met from onshore wind in 2011.

Estimated support levels and levelised costs are much lower in Denmark compared to the UK. The lower levelised costs arise from four sources: lower capital costs, lower operating costs, lower costs of capital and higher load factors.


## Context

Denmark's reserves of fossil fuel resources have decreased significantly over the last decade.[90] In November 2011, the Danish government published its future energy strategy plan.[91] It set ambitious targets for carbon-free transport and energy sectors by 2050. According to the strategic milestones of the Government, wind (including offshore) will play an important role to achieve Denmark's renewable targets. There includes a target for wind power (including onshore and offshore) to cover 52% of electricity consumption by 2020.

Since the mid-80s, onshore wind capacities increased steadily (see Figure 25). At the end of 2011, total wind onshore capacity in Denmark amounted to 3081 MW. Onshore wind generation in 2011 equalled 6.4 TWh, accounting for 65.4% of the total wind generation and for 18% of final electricity consumption[92].

Denmark is often considered the founder of modern wind energy industry. In the late 1970s, R&D provided to support wind energy led to the development of the standard technology based on the three-bladed wind turbine. Vestas, at the time a Danish crane manufacturer and today the largest manufacturers of wind turbines world-wide,[93] purchased the manufacturing rights for the three-bladed design in 1979 and started commercial production.[94]

---

90 According to the Energy Statistics 2011, gas and oil reserves have decreased by 38% and 30% compared to 2000.

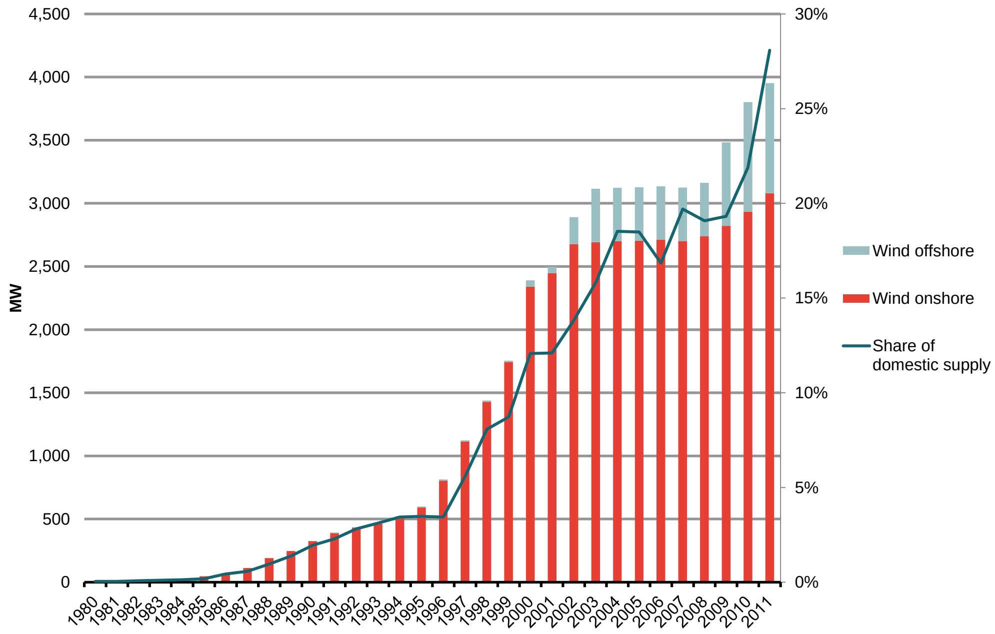
91 The Danish Government (2012), *Our future energy, November 2011.*

92 Danish Energy Agency (2012), *Energy Statistics 2011.*

93 http://www.vestas.com/en/media/news/news-display.aspx?action=3&NewsID=3037

94 See AquamarinePower (2010), *The Danish wind industry 1980 - 2010: lessons for the British marine energy industry.*

**Figure 25.** Wind capacities and share of supply in Denmark




Source: Danish Energy Agency (DEA), Energy Statistics 2011

Denmark is geographically well suited to host a significant wind industry. Denmark's location between the North and Baltic Sea and its long coast line lead to mean wind speeds between 7 and 9 m/s (at 80 metre height), above the mean wind speed of most other European countries[95]. In particular its Western coastal areas offer attractive locations for wind farms and led to a focus of development in this part.

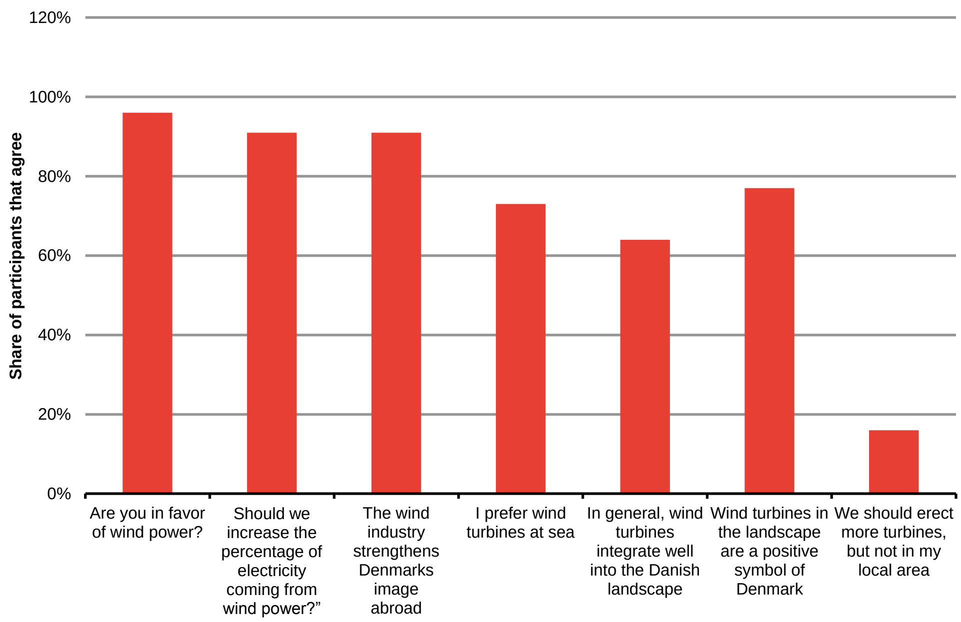
Denmark has an economically important wind industry that employs over 25 thousand people. In 2011, total exports of wind turbines, components and services amounted to DKK 38.8 bn (£4.5 bn). This represents 6.4% of total Danish exports[96].

Alongside the ambitious energy policy target, there is strong public support for wind power. The AC Nielsen Survey conducted in 2006 showed high support for wind, even in the vicinity of survey participants. This is summarised in Figure 26.

95 http://www.3tier.com/static/ttcms/us/images/support/maps/3tier_5km_global_wind_speed.pdf

96 http://www.windpower.org/da/viden/statistik/branchestatistik.html

**Figure 26.** Danish public opinion on wind energy




Source: AC Nielsen Survey (2006), cited in Jakob Lau Holst, *Danes are Wild about Wind*

## Main support scheme(s)

### Current situation

In Denmark, electricity generation from renewables is promoted through a premium tariff system. The principles of support for renewable generation in Denmark are set out in the Law on the Promotion of Renewable Energy (VE-Lov).[97] The law makes the following provision for wind turbines connected to the grid since 21 February 2008:

- Wind generators are responsible for sales of their output and receive a fixed premium on top of the market price. A price supplement of 250 DKK/MWh (£29.1/MWh) for the first 22,000 full load hours[98] is provided.

---

97 Act no. 1392 of December 2008.

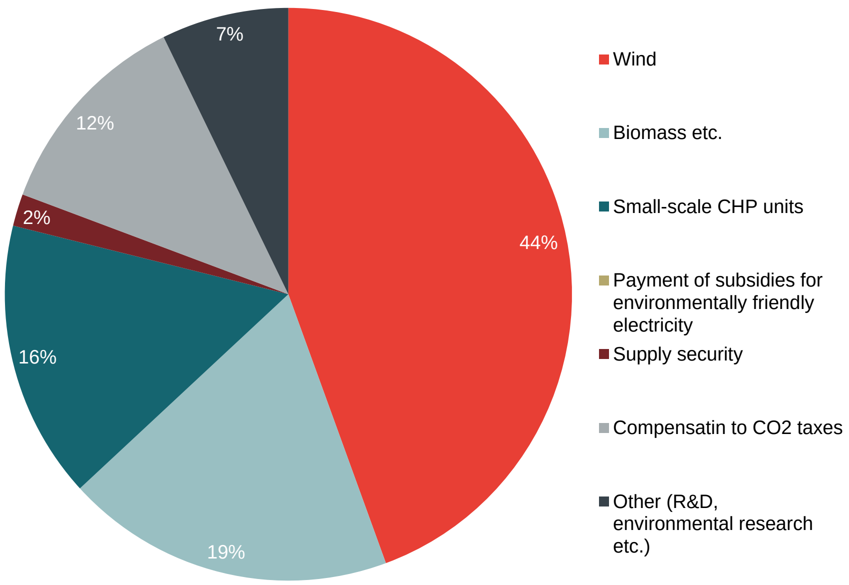
98 Full load hour is defined as the „hours of production at the wind turbine's installed output", see §5 (1) VE-Lov.

- In addition, generators receive a refund for balancing costs of 23 DKK/MWh (£2.7/MWh). [99] The support levels are held constant in nominal terms.

The nominal level of price supplements is locked in once a plant is connected to the grid and no degression is applied to the support level of future plants.

The cost of renewables support is recovered through a levy on consumer bills, the public service obligation (PSO). Total PSO expenses in 2011 amounted to 3.3 billion DKK (£385m). The contribution of onshore and offshore wind combined equalled 44% (1.5bn DKK, £171m) as illustrated in Figure 27.

**Figure 27.** Expenditures to public service obligations (PSO) in 2011




Source: Frontier based on Danish Energy Agency (2012), *Energy Statistics 2011*

## History of support scheme and deployment

Before 1989, the Danish government granted investment support for the installation of wind turbines. From 1984 to 2001, the support regime was changed from an investment cost subsidy to a mechanism depending on the actual generation of a wind: the price paid to generators amounted to 85% of the local retail price. In 1991, the dependency on the retail price was replaced by a premium payment on top of the wholesale price. The level of the premium primarily depends on the date of the grid connection.

---

99 §36 VE-Lov.

Although there are no regular review periods for the price supplements, in the past adjustments have been made every three to five years. Table 11 gives an overview of changes to the support scheme since 2000.

**Table 11.** History of support levels for onshore wind since 2000 (nominal prices)

| Date of grid connection | Support scheme | Duration of support | Remarks |
|---|---|---|---|
| **Since 21 Feb 2008** | PFiT of 250 DKK/MWh plus 23 DKK/MWh for balancing costs | 22,000 full load hours | Generator bears wholesale price risk |
| **2005 to 20 Feb 2008** | PFiT of 100 DKK/MWh plus 23 DKK/MWh for balancing costs | 20 years | Generator bears wholesale price risk |
| **2003 to 2004** | PFiT of 100 DKK/MWh plus 23 DKK/MWh for balancing cost, PFiT capped such that total revenue does not exceed 360 DKK/MWh | 20 years | Generator bears wholesale price risk; chances partly limited |
| **2000 to 2002** | FiT (CfD) scheme with price supplement adjusted such that total revenue equals 430 DKK/MWh until full load limit is reached<br><br>After expiry, price supplement of 100 DKK/MWh plus 23 DKK/MWh for balancing costs, supplement adjusted such that total revenue does not exceed 360 DKK/MWh | 20 years<br><br>Limit of 22,000 full -load hours for high premium | TSO responsible for sales on the spot market until full load hour limit is reached |

Source: Frontier based on Danish Energy Agency, The wind turbine industry-a historical flagship, Memo, May 2011

Remark: Price supplements in the VE-Lov are in nominal terms and are not indexed.

A further distinction of support levels (in nominal terms) is made with respect to the following three categories.[100]

- **Household turbines** (§41 VE-Lov) – Turbines with a capacity of 25 kW or lower receive a variable price supplement for electricity sold on the market such that total revenues amount to 600 DKK/MWh. The amount is regardless of the date of grid connection.

- **Repowering (scrapping certificates)** (§42 VE-Lov) – The law includes special provisions for new turbines that replace dismantled old turbines (scrapping certificates). The *additional* price supplement is paid for 12,000 full load hours for the part of the production that is covered by the scrapping

[100] See Danish Energy Agency (2011), *The wind turbine industry-a historical flagship, Memo.*

certificate. The level of the price supplement depends on the date of grid connection of the new turbine, the date of dismantling and capacity of the replaced turbine[101].

In the past subsidies granted under special agreement to power companies have also been important[102].

Figure 28 shows the development of support levels per MWh for new onshore wind plant since electricity market liberalisation in 1999. The initial level of financial support is plotted alongside the annual net capacity additions. We can distinguish three phases:

- **Growth (1999 to 2002)**: Wind operators received a fixed payment per MWh and did not bear wholesale price risk. The implicit premium on top of the wholesale price was higher than in later years and lead to a steady growth of 310 MW per year on average during that period 1999 to 2002.

- **Stagnation (2003-2007)**: Between 2003 and 2007, generators received a fixed premium per MWh and faced wholesale price risk. Although the premium was paid for a longer period and wholesale prices increased, the expansion of onshore wind came to a halt.

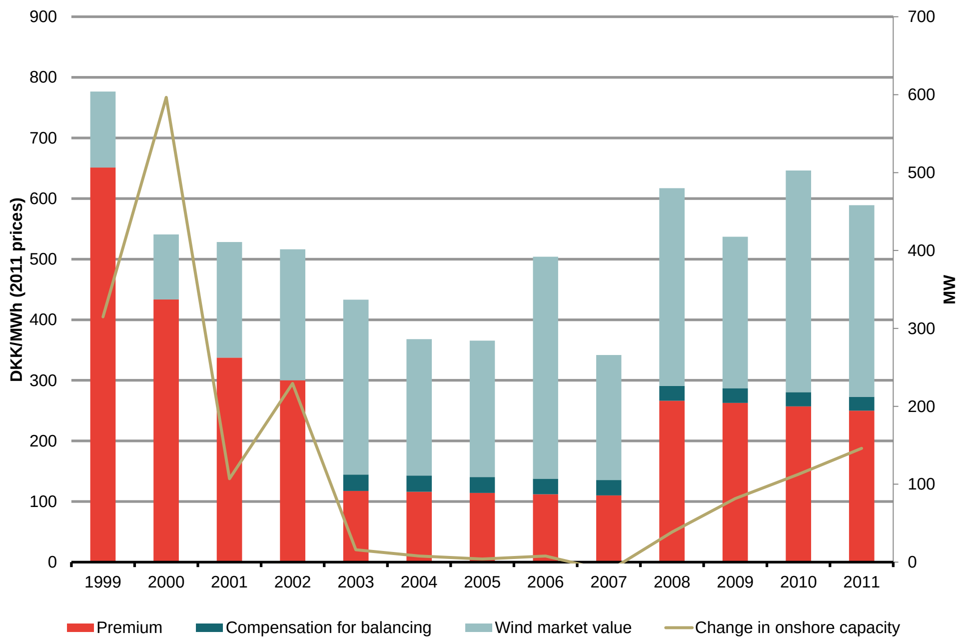
- **Recovery (since 2008)**: From February 2008 onwards, following an agreement[103] between the Danish Government and other parliamentary parties the fixed premium more than doubled from 100 to 250 DKK/MWh and lead to a recovery of capacity additions, but at a lower level than in the initial growth period.

101 For example, a new turbine connected to the grid between 1st February 2008 and 31st December 2010 receives for the production that is covered by a scrapping certificates either a supplement of 120 DKK/MWh (but not more than 380 DKK/MWh in total) or alternatively a fixed supplement of 80 DKK/MWh.

102 Wind turbines financed by power companies (§40 VE-Lov) – Wind turbines financed by power companies that have been installed as a result of an order/requirement or special agreements. Up to the scheme's expiry in 2002, a variable price supplement was provided for a period of 10 years such that premium plus market price equals DKK 430 DKK/MWh. Thereafter until 20 years of operation, the price supplement is reduced to 100 DKK/MWh, and a cap on total revenues is imposed of 360 DKK/MWh. These requirements for power companies from 1985 to 2002 were viewed as crucial to early expansion rates of onshore wind.

103 http://www.ens.dk/en-US/policy/danish-climate-and-energy-policy/political-agreements/Sider/February2008Agreementfor2008-2011.aspx

**Figure 28.** Development of absolute support for onshore wind in the first year of operation (2011 prices)




Source: Frontier

Remarks: Market value of wind onshore set equal to 90% of average annual spot price (Nordpool system price). Until 2002, wind generators were guaranteed a total support level. The premium is calculated as the difference to the market value. The duration of the support level above changes over time: for the period 2003-2007 support level is granted for 20 years, for other periods only up to 22,000 full load hours. Since 2003, total support varies with the spot price. Nominal values converted into 2011 prices using the CPI index published by the Danish Statistical Office.

Since 2001, funding for wind power subsidies has been recovered through a price supplement on final customer bills, the PSO. Figure 29 shows total payments for onshore and offshore wind combined since 2005.[104] Total expenditures in 2011 prices fluctuate between 1.9 billion DKK in 2005 and 0.7 billion DKK in 2008. This fluctuation is driven by:

- the development of wholesale market price for electricity – higher prices lead to lower price supplements for turbines with guaranteed or capped revenues[105]; and

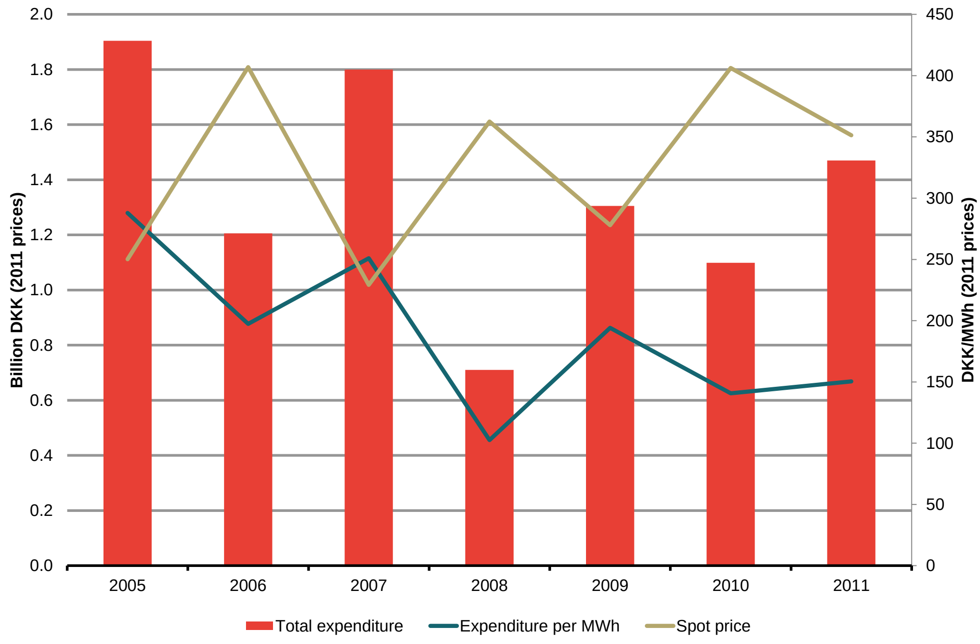
104 Before 2005, the energy statistics published by the Danish Energy Agency did not report a funding for wind separately but only total funding for renewables and combined-heat and power plants.

105 This is relevant for new turbines connected prior to 2005, or after 2005 only if they receive additional payments for scrapping certificates.

- fluctuations of wind production due to deviations from a normal wind year and changes in installed capacity.

Figure 29 also reveals that average expenditures per MWh wind generation varies between 100 DKK/MWh in 2008 and 290 DKK/MWh in 2005 (real prices 2011). Based on market exchange rates in 2011 this is equivalent to £10.6-26.6 /MWh.

**Figure 29.** Expenditures to public service obligations (PSO) on electricity for wind onshore and offshore wind 2005-2011 (2011 prices)




Source: Frontier based on Danish Energy Agency (2012), *Energy statistics 2011*

Nominal values converted into 2011 prices using the CPI index published by the Danish Statistical Office

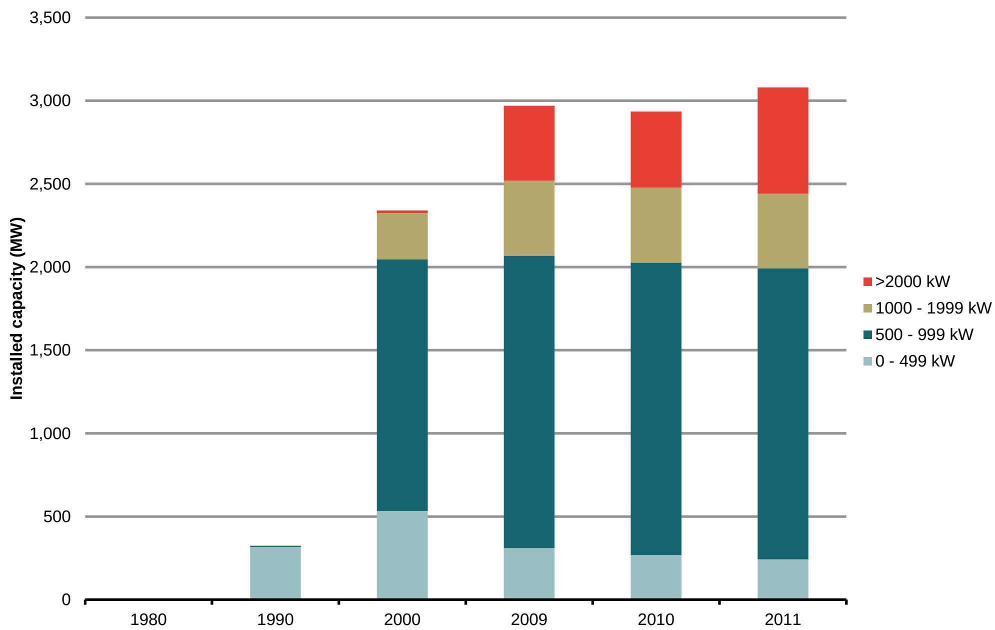
Figure 30 shows the composition of the wind turbines with respect to size.

- Until 2000, the vast majority of erected turbines had a nameplate capacity of below 1MW.

- Since 2000, the number of turbines installed in Denmark has dropped by c. 30% compared to 2000 while the installed capacity has increased by 30%. This is caused by decommissioning and repowering of smaller turbines.

- In the last two years, net additions have only come from turbines with name plate capacities of above 2MW.

**Figure 30.** Installed wind onshore capacity in Denmark by turbine size




Source: Danish Energy Agency, Energy Statistics 2010 and 2011

## Costs of wind deployment

## Capital costs

Table 12 provides an overview of recent estimates of the total capital costs for a wind turbine onshore in Denmark. Costs in 2011 prices[106] range from 7.67 million DKK/MW to 12.67 million DKK (£0.89-1.47m/MW).

106 We used the GDP deflator index published by the World Bank to convert all prices into 2011 prices.

**Table 12.** Capital cost estimates for onshore wind in Denmark, 2011

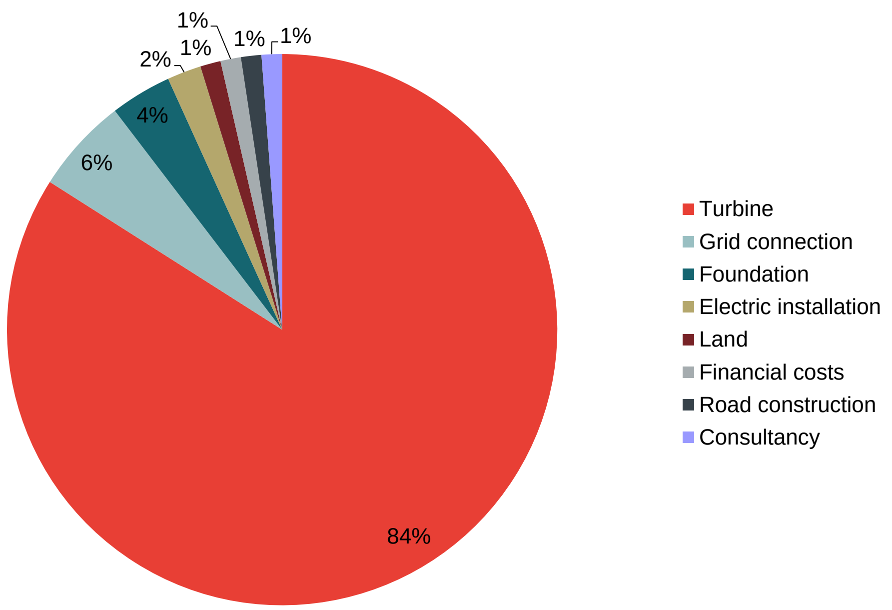
| | mDKK/MW | £m/MW |
|---|---|---|
| **IEA Wind (2012)** | 7.67 | 0.89 |
| **Schwabe et al (2011)** | 9.92 | 1.16 |
| **EA (2012)** | 8.20 – 12.67 | 0.95 – 1.47 |
| **Lantz et al. (2012)** | 10.72 – 11.01 | 1.25 – 1.28 |

Source: Frontier

Remark: Costs have been converted into 2011 prices using the GDP deflator and the market exchange rates for US $, € and £ in 2011.

Figure 31 shows a typical decomposition of the capital costs for a medium-sized onshore turbine in Denmark.

**Figure 31.** Decomposition of capital costs for a windfarm using medium-sized onshore turbines in Denmark




Source: Frontier based on EWEA (2009), table 1.2

Remark: For grid connection we chose the lower bound due to the connection regime in Denmark.

By far the highest share of capital costs stems from the purchase price for the wind turbine. The weight of the various cost components varies depending on turbine size, distance from grids, geological conditions and land ownership structure. The second highest cost driver, the costs for grid connections, account for 6%. However, it is notable that connection costs are only incurred to the nearest 10 kV connection point, even if larger reinforcement is necessary.

## Operating costs

Table 13 provides an overview of operating cost estimates for windfarms in Denmark.

**Table 13.** Operating costs for onshore wind in Denmark, 2011

| | DKK | | £ | |
|---|---|---|---|---|
| **Source** | **Fixed O&M [DKK'000/MW/yr]** | **Variable O&M [DKK/MWh]** | **Fixed O&M [£'000/MW/yr]** | **Variable O&M [£ per MWh]** |
| **IRENA (2012)** | | 83.5 - 104.1 | | 9.7 – 12.1 |
| **Schwabe et al. (2011)** | | 95.3 | | 11.1 |
| **EA (2012)** | 298 - 410 | | 34.7 – 47.7 | |
| **Lantz et al. (2012)** | | 92.3 | | 10.7 |

Source: Frontier

Not all sources in the literature distinguish between fixed and variable O&M costs, and it is not uncommon for operating costs to be quoted as either fully fixed or fully variable. There is a trend towards lower operating costs for new and larger machines.[107]

## Cost of capital

Three recent studies provide estimates of the post-tax WACC for onshore wind in Denmark. These are as follows where we have converting all WACC estimates into pre-tax real figures[108].

---

107 EWEA (2009), *The Economics of Wind Energy – A report by the European Wind Energy Association.*

108 Nominal WACC values have been converted into real using the average CPI inflation of 2.1% over the last decade. Original values in sources above are denoted as post-tax WACC and were converted into pre-tax applying the corporate tax rate of 25%. We assumed 80% gearing at 5% cost of debt where no information on the financing structure was provided.

- **Schwabe et al** (2011) estimate a post-tax nominal WACC of 5.2% equivalent to a pre-tax real WACC of 4.7%[109].

- **EA** (2012) estimate a post-tax, real value of 7.6% equivalent to 10.1% pre-tax, real[110].

- **Lantz et al.** (2012) cite a post-tax nominal value of 8% equivalent to 7.7% pre-tax, real[111].

The average pre-tax, real WACC for onshore investments is 7.5%, with significant variation between the sources.

### Load factors

The majority of wind turbines in Denmark are designed to start producing electricity at a wind speed of 4 metres per second (m/s) and reach their maximum production volume at wind speeds of 12-15 m/s. Modern turbines typically produce at maximum output for 2,500 – 2,700 hours a year (load factors of 29-31%).[112] In very good sites modern turbines may even achieve 3000 hours a year (load factor of 34%) or higher.[113]

We assume a load factor in our central case of 31% with load and high values of 29% and 34% respectively.

### Levelised costs

Capital costs and operating costs, as well as load factors, may vary across projects. To capture a wide range of projects, we calculate the levelised costs for onshore wind in Denmark in 2011 based on three possible cost levels. The assumptions can be found in the table below.

---

109 Schwabe et al (2011), *IEA Wind Task 26: Multinational Case Study.*

110 EA (2012), *Effect of new subsidy scheme on technology choice and deployment.*

111 Lantz et al. (2012), *IEA Wind Task 26. The Past and Future Cost of Wind Energy.*

112 Danish Energy Agency (2009),*Wind turbines in Denmark*; Schwalbe et al (2011), IEA (2011), *Wind Task 26.*

113 See Lantz et al (2012)., IEA Wind Task 26, *The Past and Future Cost of Wind Energy.*

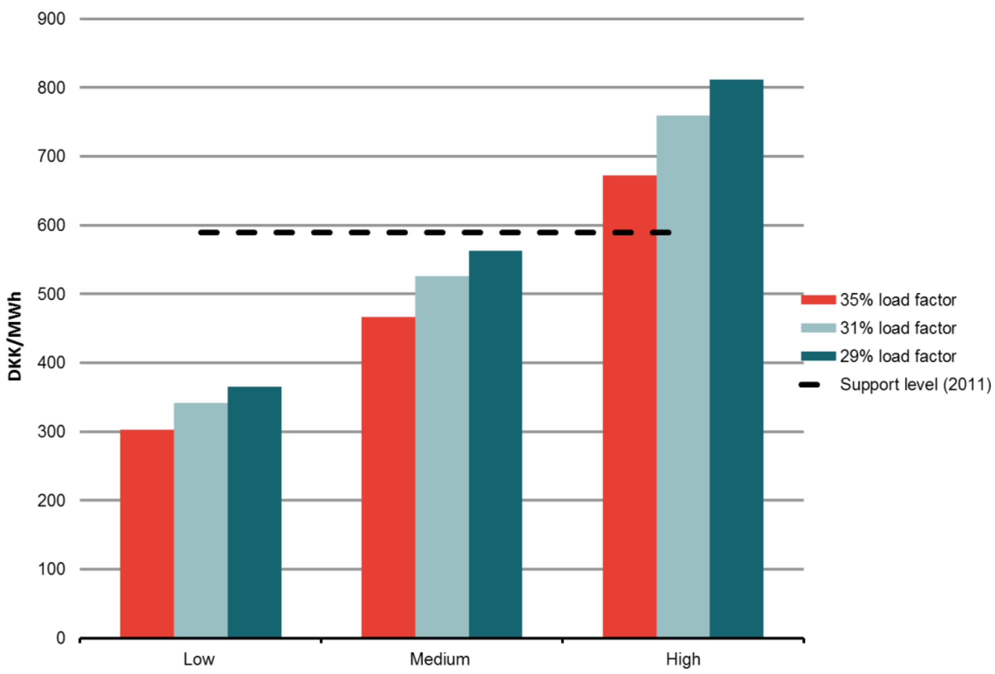
**Table 14.** Assumptions for calculation of levelised costs in Denmark (2011 prices)

| Item | Low | Medium | High | Source/ remarks |
|---|---|---|---|---|
| **Capital costs [DKKm/MW]** | 7.67 | 10.18 | 12.67 | Various sources, see Table 12 |
| **Fixed operating costs [DKK'000/MW /year]** | 298 | 354 | 410 | Various sources, see Table 13 |
| **WACC (real, pre-tax)** | 4.7% | 7.5% | 10.1% | Various sources |
| **Year of operation** | 20 | 20 | 20 | |

Source: Frontier

We calculate the levelised costs using three different load factors. The results are presented in Figure 32.

**Figure 32**. Levelised costs of wind onshore in Denmark (DKK/MWh, 2011 prices)




Source: Data from various sources, analysis by Frontier Economics

Our calculations show that for 2011, the support level (including spot market revenues) was sufficient to cover the levelised costs for the low cost and medium cost level. Only for turbines with high costs, levelised costs exceed the support level for any of the three load factors.

## Other factors influencing deployment

### Other support measures

In addition to the main support schemes described above there are three other support measures which help support wind at a local and small scale.

- **Net-metering**: Wind generators connected to private supply systems are exempted from paying the green energy levy (Public Service Obligation, PSO). Plants must be connected to a collective grid, installed at the place of consumption and fully owned by the consumer.[114] Wind plants are only eligible if the plant is connected to a private supply system or if the plant is

114 § 3 par. 3 BEK 1068/2012.

located at the place of consumption (§ 3 par. 2, 4 and § 4 par. 2, 3 BEK 1068/2012). The PSO tariff in 2012 is at 182 DKK/MWh (21.2 £/MWh).[115]

- **Tax exemption** for households that generate their own electricity. This led to the wind turbine cooperatives of which the first were founded in the 1980s. By 1996 there were more than 2,000 wind turbine cooperatives in Denmark and in 2004 more than 150,000 Danish families belonged to a cooperative. However, in recent years many cooperatives have been closed due to the inefficiency of small wind turbines compared to larger ones.[116]

- **Loan guarantees**. Local initiatives for the construction of wind energy plants are supported through loan guarantees. Small renewable electricity generation installations deemed to be of strategic importance in Denmark are eligible for loans guarantees from the System Operator (Engerginet) to cover development spend such as siting studies. A maximum guarantee of DKK 500,000 (£60,000) may be granted per project[117].

## Grid access

In Denmark, there is a special connection policy for wind turbines. Wind generators have prioritised access to the network.[118] The average lead time for grid access in Denmark in 2008 was around 2 months, among the shortest of all European countries.[119] The very low lead time might be partly driven by the relatively low number of new onshore wind farms (12 projects with a combined capacity of 72MW[120]) in that period.

## Planning and community benefits

In 2009 the Promotion of Renewable Energy Act (VE-Lov) introduced four schemes to promote public acceptance and participation of the local population in the development of onshore wind turbines:

- a loss-of-value scheme;
- an option-to-purchase scheme;

---

115 http://energinet.dk/EN/El/Engrosmarked/Tariffer-og-priser/Sider/Aktuelle-tariffer-og-gebyrer.aspx

116 See http://denmark.dk/en/green-living/wind-energy/

117 See http://www.iea.org/dbtw-wpd/Textbase/pm/?mode=re&id=4424&action=detail

118 §68 Energy Supply Act.

119 EWEA (2010), *WindBarriers - Administrative and grid access barriers to wind power.*

120 EWEA (2010), *WindBarriers - Administrative and grid access barriers to wind power.*

- a green scheme so that municipalities can improve the scenery and recreational values in areas where wind turbines are erected; and
- a guarantee scheme to support local initiative groups with preliminary investigations.

All the schemes are administered by Energinet.dk.

According to §6 Ve-Lov, wind farm operators may have to compensate for the loss of value to real property (not applicable to wind turbines with less than 25m height). Furthermore, wind farm operators that install a turbine exceeding a height of 25m have to offer at least 20% of the shares to citizens above 18 years of age living in a 4.5km radius.

As a general rule, the municipalities are responsible for the planning pertaining to the erection of onshore wind turbines. The Nature Agency under the Ministry of the Environment manages the legislation on planning activities in connection with the erection of onshore wind turbines. Environmental impact assessment (EIA of onshore wind turbine projects and environmental assessments of planning proposals at the general and strategic level are managed by the Ministry of the Environment.[121]

121 http://www.ens.dk/EN-US/SUPPLY/RENEWABLE-ENERGY/WINDPOWER/ONSHORE-WIND-POWER/Sider/Forside.aspx

# Annexe 3: Germany case study


## Summary

Germany has a long history of support for renewables. German policy has so far focused on having a mix between biomass, photovoltaic, wind and hydro rather than exploiting the cheapest and most economical technologies. However, onshore wind, which met 8% of demand in 2011, plays an important role and is the single largest source of renewable generation.

The main support scheme in 2011 was a FiT. The German FiT is fixed in nominal terms for the total support duration of 20 years. To facilitate investment in lower quality wind sites, such plants receive the higher initial FiT rate for a longer period. Support levels and levelised costs are slightly lower in Germany compared to the UK. Germany has significantly lower load factor than the UK but this is balanced by lower capital costs and cost of capital.

The latest rise in the renewable levy ("EEG Umlage") paid by final customers directly has intensified the debate how support costs could be restricted in the future.


## Context

The main policy objectives behind subsidies for renewable electricity in Germany are to facilitate a sustainable electricity supply, to reduce the costs of energy supply by developing technologies, to conserve fossil fuel resources and to promote the development of renewable technologies.[122]

Under the EU renewable target, Germany must meet 18% of its gross final energy consumption from renewables by 2020 – almost doubling the share compared to 2010. [123] The electricity sector is expected to make an important contribution to this. Renewable electricity targets and the support mechanisms are set down in the German Renewable Energy Sources Act (EEG). The targets are to meet at least

- 35% of demand by 2020;
- 50% of demand by 2030;
- 65% of demand by 2040; and

122 § 1 EEG.

123 See Directive 2009/28/EC. The National Renewable Energy Action Plan foresees an overfulfilment of the German target and expects a share of 19.6% by 2020.

- 80% of demand by 2050.[124]

Neither the EEG nor the National Renewable Energy Action Plan contain specific targets for onshore wind. The estimates in the National Renewable Action plan of 35,750MW by 2020 are likely to be exceeded. [125]

By the end of 2011, 29,075 MW of wind turbines were installed in Germany, of which the vast majority of 28,860MW were erected onshore.[126] Onshore wind contributed 8% of German electricity supply (48.3TWh).[127] During 2011 around 2,000 MW of new wind capacity was installed onshore of which 238MW was due to repowering.[128]

124 § 1 EEG.

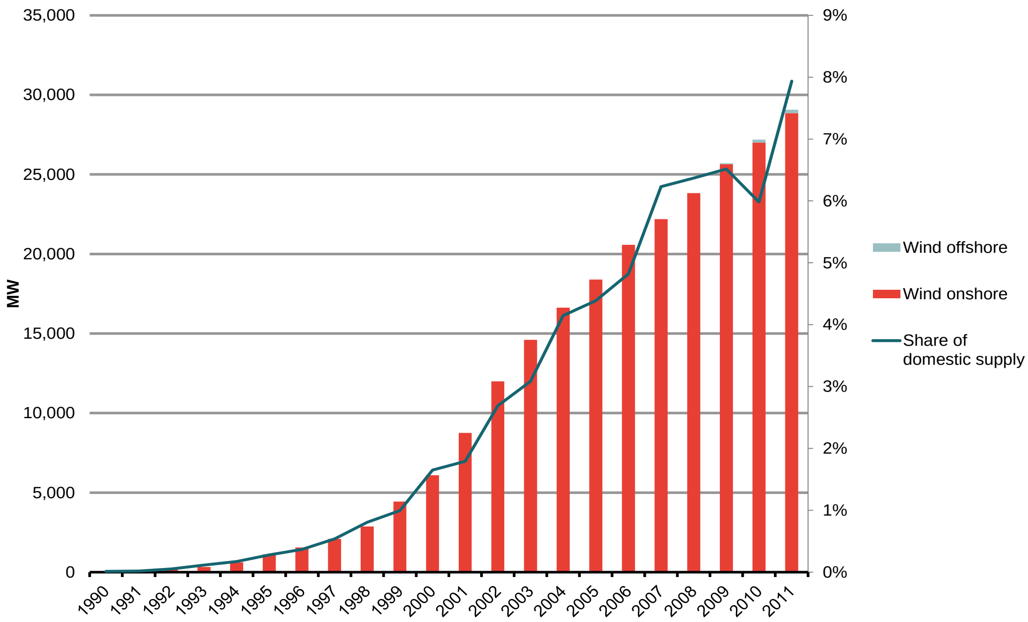
125 Federal Republic of Germany (2010), *National Renewable Energy Action Plan in accordance with Directive 2009/28/EC on the promotion of the use of energy from renewable sources.*

126 The German Wind Institute (DEWI), *Status der Windenergienutzung in Deutschland – Stand 31.12.2011.*

127 Calculated based on gross electricity production of 609 TWh reported in the Energy Statistics from the Federal Ministry of Economics and Technology (BWMi) and wind generation of 48.3 TWh reported in the Renewable Energy Time Series published by the Ministry for the Environment (BMU).

128 The German Wind Institute (DEWI), *Status der Windenergienutzung in Deutschland – Stand 31.12.2011.*

**Figure 33.** Installed wind capacity and share of supply in Germany




Source: Frontier based on data published by the BMU and BMWi

Onshore wind sites in Germany show a significant variation of average wind speed. Sites in Northern Germany, in particular in coastal areas, and at low mountain ranges in central Germany tend to have the highest average wind speed.[129] This is also reflected in the spatial distribution of wind turbines: almost a quarter of German onshore capacity (7,039 MW in 2011[130]) is installed in the Northern state of Lower Saxony. Since many of the very good sites in the North are already taken, expansion takes place in Southern states. Bavaria reached the highest percentage of new builds among all states with 24% of its total capacity installed in 2011.[131]

In Germany there has been traditionally strong public support for renewables. A recent survey conducted by the polling institute TNS Infratest on behalf of the German Renewable Energies Agency shows: [132]

- 93% support the further expansion of renewables in general; but

---

129 http://www.3tier.com/static/ttcms/us/images/support/maps/3tier_5km_global_wind_speed.pdf

130 The German Wind Institute (DEWI), *Status der Windenergienutzung in Deutschland – Stand 31.12.2011.*

131 Frontier based on data from The German Wind Institute (DEWI), *Status der Windenergienutzung in Deutschland – Stand 31.12.2011.*

132 http://www.foederal-erneuerbar.de

- only 61% support the erection of wind turbines in their vicinity (compared to 77% in solar PV parks).

The latest rise in the renewable levy ("EEG Umlage") paid by final customers has sparked a public debate on the costs for renewables. The TNS infratest poll reveals that less than 50% perceive a levy of €50€/MWh (£43/MWh) acceptable.

## Main support scheme (s)

The Renewable Energy Sources Act (EEG), introduced in 2000, is the main driver for the expansion of renewable generation in Germany. In 2011, the main support mechanism is a feed-in tariff which is differentiated across technologies, generation volumes and date of grid connection. This section describes the current situation and the evolution of the support levels over time. At the end we briefly summarise the changes to the support scheme in the EEG in 2012 where a market premium model was introduced which is closely linked to the FIT.

### *Current situation and support scheme design*

The main support scheme for onshore wind is set out in the EEG. An onshore wind generator connected to the grid in 2011 was subject to the following regulation:

- **Level and duration of support**[133] – Wind generators receive a FIT which is fixed in nominal terms for 20 years from the start generation. There two levels:
  - Higher initial tariff – for a period of at least 5 years the generator receives a fixed tariff of €90.2MWh (£78/MWh). The period is extended by two months for each 0.75 per cent of the reference yield[134] by which the yield of the wind farm is below 150 per cent of the reference yield.[135] For small plants <50kW the initial feed-in tariff is paid for 20 years irrespective of their actual yield.
  - Lower basic tariff – for the remaining time until the end of the 20 years generators receive a lower tariff of €49.2/MWh (£43/MWh) .

133 § 29, 30 EEG (2009)

134 The reference yield is defined by turbine type and published by accredited institutions, see http://www.wind-fgw.de/eeg_referenzertrag.htm.

135 For example, a wind farm that generates 100% of the reference yield receives the initial feed-in tariff for 5 + (150%-100%)/0.75%*2/12 = 16 years and one month.

- Generators may receive a bonus for repowering or for system services[136] of €4.9/MWh (£4.3/MWh). This bonus is paid for the period of the higher initial tariff.

The FiTs for future plants are digressed by 1% p.a. in nominal terms, i.e. the feed-in tariff for plants which are connected to the grid in 2012 receive 99% of the tariff of the plants connected in the previous year.[137]

- **Opting in and out**[138] – Operators may opt in and out (or choose a certain proportion) from the feed-in tariff scheme on a monthly basis. If a generator opts out, he is responsible for selling the power as well as for balancing. Feed-in tariffs are only paid for energy which is not marketed directly. The period in which the generator opts out from the FIT is credited against the duration of the FIT payment.

- **Role of TSOs** – TSOs are responsible for paying out the feed-in tariffs to the generators on a monthly basis and for balancing. They take on the renewable generation and have to sell it on the day-ahead spot market.[139] These responsibilities are valid as long as the wind generator receives the FIT.

- **Cost allocation** – TSOs recover all costs which occur in relation to their responsibilities with the promotion of renewables through a levy on final consumer bills ( "EEG-Umlage").[140] The levy is calculated on a national level and amounted to €35.3 per MWh (£31/MWh) consumed by final customers in 2011.[141]

In 2011, total FIT payments amounted to €4.1bn for wind onshore generation of 45TWh which was remunerated under the scheme.[142] This implies an average feed-in tariff in 2011 of €91.8/MWh. (£80/MWh).

---

136 Turbines have to fulfill certain technical requirements to improve their grid integration. These requirements are set out in a separate ordinance.

137 In the update of the EEG in 2012, the digression factor was increased to 1.5% p.a.

138 §17 EEG (2009).

139 Ordinance AuglMechAV determines how TSO have to market RES-E in detail. In general TSOs have to sell the forecasted RES-E on the day-ahead market irrespective of the price. If the power exchange EPEX Spot calls for a second auction due to negative prices TSOs submit randomised bids with limits between -150 and -350€/MWh. Only if technically unavoidable for the stability of the grid, renewable generators may be ramped down but receive a compensation equal to 95% of the regular FiT payments (§11 and 12 EEG).

140 The Federal Office of Economics and Export Control (BAFA) may limit the EEG levy for energy intense industries.

141 http://www.eeg-kwk.net/de/EEG-Umlage%202011.htm

142 Annual EEG Acount 2011, published by the 4 German TSOs on www.eeg-kwk.net

## History of main support scheme and deployment

The EEG has been the main driver for the expansion of renewables. Since its introduction in 2000, renewable capacities have increased more than sevenfold and wind capacities more than sixfold.[143]

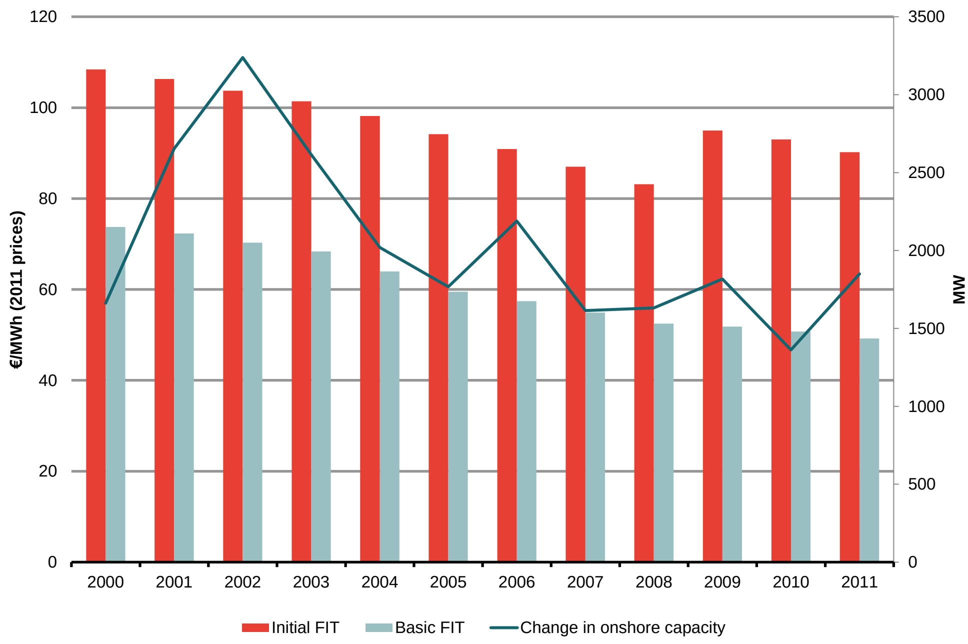
There are no regular review periods for the support levels in the EEG. However, the EEG has historically been reviewed at least every two years.

Figure 34 shows the development of the initial and basic FiT alongside the annual net capacity additions for wind onshore in Germany. Except for a one-time increase in the initial tariffs in 2009, feed-in tariffs have declined at a rate of 3% in real terms. This reflects:

- A decline in the FiT between 2001-2008 of 2% in nominal terms plus inflation of 1.7% – during this period c. 2200 MW were added per year; and
- a one-off increase in the initial tariff of 14% in real terms in 2009, followed by a nominal digression of 1% plus inflation of 1.4% – during this period c. 1700 MW were added per year.

143 BMU (2012), Time series on the development of renewable energies in Germany.

**Figure 34.** Development of initial and basic feed-in tariffs for a wind onshore turbine in Germany (2011 prices)




Source: Frontier

Remarks: The duration for which the higher initial tariff is paid varies with the full load hours of the turbine. Tariff levels are fixed in nominal terms, i.e. even without any changes to the EEG real tariffs decline with CPI inflation.

## Recent developments

In 2012, a market premium model was introduced which coexists with the traditional FiT model. Generators can switch between the FiT and the market premium on a monthly basis. The level of the market premium is closely linked to the feed-in tariff and is designed to compensate for the difference between sales revenues when wind generators market their output themselves and pay for balancing and the traditional FiT where the responsibility for these tasks lies with the TSO. In addition, generators receive a premium to compensate for administrative costs of sale.

## Costs of wind deployment

### Capital costs

We have reviewed several recent studies on capital costs for onshore wind in Germany. The summary presented in Table 15 show a significant variation in capital costs, ranging from 0.98 to 1.79 €m/MW (0.85 to 1.56 £m/MW).

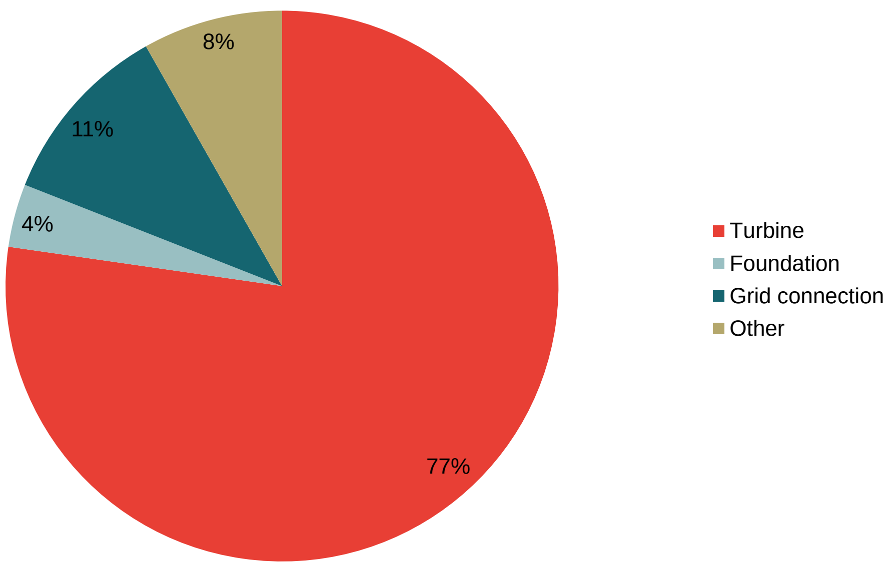
**Table 15.** Capital cost estimates for onshore wind in Germany, 2011

| Source | €m/MW | £m/MW |
|---|---|---|
| **Schwabe et al. (2011)** | 1.41 | 1.23 |
| **BMU (2011)** | 1.35-1.77 | 1.17-1.54 |
| **UBA (2012)** | 1.06-1.35 | 0.93-1.17 |
| **DRL et al. (2012)** | 1.07 | 0.93 |
| **Frauenhofer ISE (2012)** | 0.99-1.34 | 0.86-1.16 |

Source: Frontier. Values have been converted into 2011 prices using the GDP deflator index for Germany.

The majority of capital costs are associated with the purchase of the turbines and construction. A typical breakdown of capital costs for a 2MW turbine is shown below in Figure 35.

**Figure 35.** Breakdown of capital costs for an onshore windfarm using 2MW turbines in Germany




Source: Frontier based on Eggersglüß (2012), *Windkraftanlagen Technologie und Wirtschaftlichkeit*.

## Operating costs

Operating costs include operations and maintenance (O&M) costs, insurance and land rent. Grid charges are not included since in Germany network costs are recovered through demand-side charges.

**Table 16.** Operating costs for onshore wind in Germany, 2011

| Source | € | | £ | |
|---|---|---|---|---|
| | Fixed O&M [€'000/MW/yr] | Variable O&M [€/MWh] | Fixed O&M [£'000/MW/yr] | Variable O&M [£ per MWh] |
| **Schwabe et al. (2011)** | 47.7 | | 41.4 | |
| **Eggersglüß (2012)** | | 25.2 | | 21.9 |
| **BMU (2011)** | | 22.1 - 25.1 | | 19.2 - 21.8 |
| **DRL et al. (2012)** | 48.4 | | 42.0 | |
| **Frauenhofer ISE (2012)** | | 14.9 | | 12.9 |

Source: Frontier

Remark: Nominal values have been converted into 2011 prices applying the GDP deflator index for Germany.

Not all sources in the literature distinguish between fixed and variable O&M costs, and it is not uncommon for operating costs to be quoted as either fully fixed or fully variable.

## Cost of capital

Five recent studies provide estimates cost of capital for onshore wind in Germany. We have converted all WACC estimates into pre-tax real figures[144].

- **Schwabe et al.** (2011) estimate a post-tax nominal WACC of 5.6% – this is equivalent to a pre-tax real WACC of 6.3%.[145]

144 Nominal WACC values have been converted into real using the average CPI inflation of 1.6% over the last decade. Original values in sources above are denoted as post-tax WACC and were converted into pre-tax applying an average tax rate of 28.9% for German companies (corporation tax is only 15% and does not reflect the actual tax burden).

- **Deutsche Winguard** (2010) cite 7.5% (nominal, pre-tax) as a typical WACC for German onshore projects – this equals a real pre-tax WACC of 5.8%.[146]

- **BMU** (2011): In its experience report, the ministry applies a gearing of 75%, a nominal cost of debt of 5-5.5% and cost of equity of 12% to determine the generation costs of onshore wind. Converted into real terms, this gives a range of 5.1% - 5.4%.[147]

- **DRL et al.** (2012) in their long-term study prepared for the BMU (Ministry of the Environment) assume a real discount rate of 6%.[148]

- **Frauenhofer ISE** (2012) uses a gearing of 70%, a nominal cost of debt of 5-5.5% and cost of equity of 9% to calculate levelised costs for wind onshore in Germany. This translates into a real pre-tax WACC of 5.9%.[149]

The average real pre-tax WACC for onshore investments from these studies is 5.8%, with some limited variation between the sources.

### Load factors

Figure 36 shows average load factors for onshore wind in the Germany in recent years. Between 2002 and 2011 the average load factor for onshore wind farms in Germany was 17%.

---

145 Schwabe et al (2011), *IEA Wind Task 26: Multinational Case Study.*

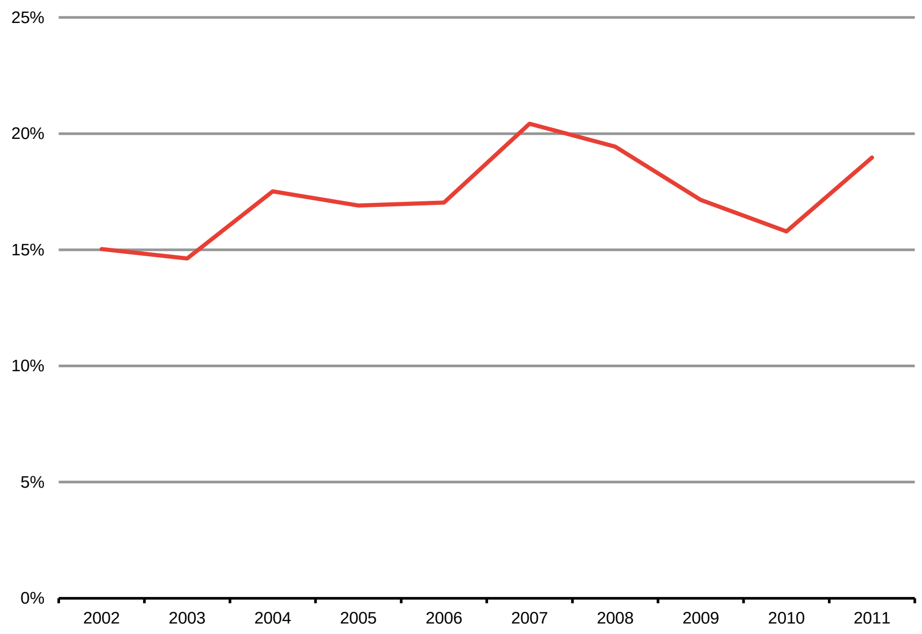
146 Deutsche Windguard (2010), *Kostensituation der Windenergie in Deutschland.*

147 BMU, *Erfahrungsbericht 2011 zum EEG*, Draft as of 3.5.2011.

148 DRL et al (2012), *Langfristszenarien und Strategien für den Ausbau der erneuerbaren Energien in Deutschland bei Berücksichtigung der Entwicklung in Europa und global, Datenanhang II zum Schlussbericht.*

149 Frauenhofer ISE (2012), *Studie Stromgestehungskosten Erneuerbare Energien*, Mai 2012.

**Figure 36.** Onshore wind average load factors in Germany




Source: Frontier based on data published by the BMU and BWMi

For new projects there is a wide range of possible load factors depending on the turbine type and site quality:

- **Frauenhofer ISE** (2012) assumes load factors between 15% (1300 full-load hours p.a.) for interior sites and 23% (2000 full-load hours p.a.) for costal sites.[150]
- **Schwabe et al** (2011) use a load factor of 26% (2260 full-load hours p.a.).[151]
- **Eggersglüß** (2012) cite a range of 20% to 25% (1750 to 2170 full-load hours p.a.) for a turbine at a 70% quality site.[152 153]

New turbines may be technically able to achieve higher load factors but the availability of good wind sites is a major constraint in Germany. Deutsche Windguard (2011) have estimated the average site quality of 82% for 258 planned

150 Frauenhofer ISE (2012), *Studie Stromgestehungskosten Erneuerbare Energien*, Mai 2012.

151 Schwabe et al (2011), *IEA Wind Task 26: Multinational Case Study.*

152 Eggersglüß (2012), *Windkraftanlagen Technologie und Wirtschaftlichkeit.*

153 The quality of a site is determined in relation to the generation of the same turbine type at a site with average wind speed of 5.5m/s in 30 metres along with further detailed requirements (Annex 3, EEG). This reference generation is determined for each turbine type by accredited institutions.

onshore projects in 2012 and 2013, of which 52 projects (c. 20%) are repowering projects. Almost two thirds of the projects have a site quality between 71% and 90%. One main driver for the site quality varies with the geographic location: sites in coastal areas have typically a significantly higher quality than in the interior of Germany.[154]

## Levelised costs

Capital costs and operating costs, as well as load factors, may vary across projects. To capture a wide range of projects, we calculate the levelised costs for onshore wind in Germany in 2011 based on three possible cost levels. The assumptions can be found in the table below.

**Table 17.** Assumptions for calculation of levelised costs in Germany (2011 prices)

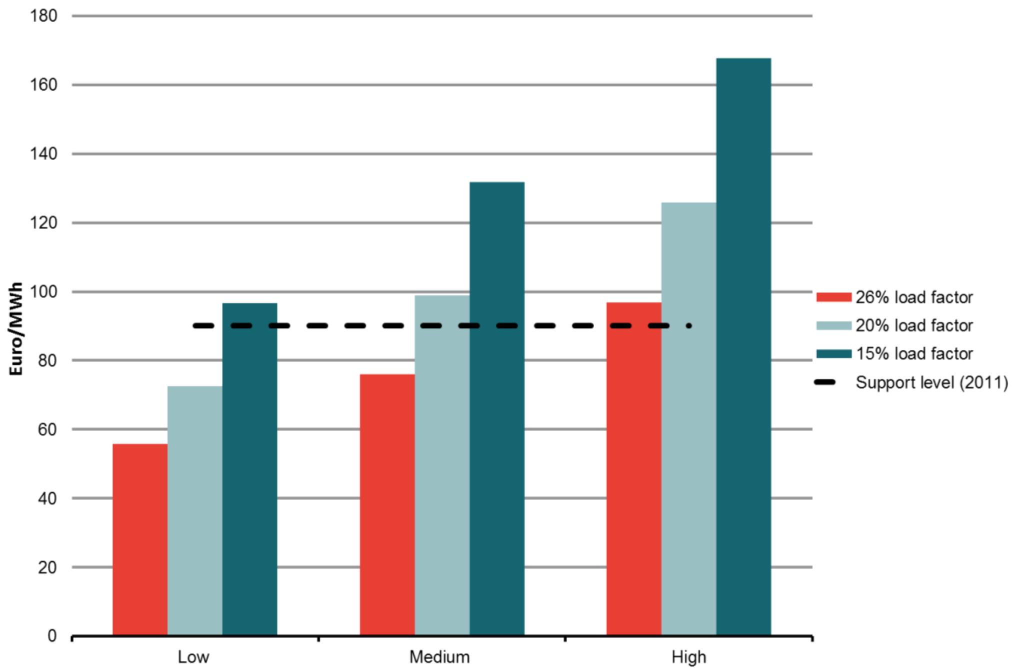
| Item | Low | Medium | High | Source/ remarks |
|---|---|---|---|---|
| **Capital costs [€m/MW]** | 0.99 | 1.38 | 1.77 | Various sources, see Table 15 |
| **Operating costs [€'000/MW/yr]** | 42.9 | 47.7 | 52.4 | Schwalbe et al. (2011) for medium level, +/- 10% variation |
| **WACC (real, pre-tax)** | 5.1% | 5.8% | 6.3% | Various sources, see page 101 |
| **Years of operation** | 20 | 20 | 20 | |

Source: Frontier

We calculate the levelised costs using three different load factors. The results are presented in Figure 37.

154 Deutsche Windguard (2011), *Auswirkungen des Regierungsentwurfs zum EEG 2012 auf die Windenergie an Land.*

**Figure 37**. Levelised costs of onshore wind in Germany (€/MWh, 2011 prices)




Source: Data from various sources, analysis by Frontier Economics

Our calculations show that for 2011, the support level (intial feed-in tariff for a new plant in 2011) was sufficient to cover the levelised costs for the low cost and medium cost level if the load factor is sufficiently high. Only for turbines with high costs, levelised costs exceed the support level at all load factors. However, this does not necessarily imply that investment will come to halt in Germany. Small private investors and municipal utilities that are responsible for more than 40% of investments in 2011[155] tend to accept lower returns on equity. Furthermore, the support level in graph above does not account for higher revenues from opting out the main support scheme to benefit from the 'Green electricity privilege' (see below).

## Other factors influencing deployment

In the following we summarise other support measure for wind onshore in Germany that are not factored in the levelised costs estimates above.

155 trend:research (2011), *Marktakteure Erneuerbare-Energien-Anlagen in der Stromerzeugung.*

## Other support measures

- **"Green electricity privilege".** Electricity supply companies were exempted from the EEG levy (€35.3 per MWh or £30.6 per MWh in 2011) if they procured at least 50 percent of the electricity delivered to final consumers from renewable energy plants (including onshore wind). This increases the value of wind power which is marketed directly by up to twice the EEG levy (€70.6 or £61.2 per MWh) on top of the wholesale price.[156] Wind generators that market their output directly receive no feed-in tariff, i.e. this is not additive to the primary support scheme (FiT).[157]

- **R&D.** The Federal Energy Research Program in 2011 included 74 new projects (including financial extension of ongoing projects) that have been funded by € 77.1m (£67m). A little less than half of the new projects deal with onshore or general wind topics with the rest focused on offshore topics[158]

- **Financing support.** The public-sector financial institution "KfW Bankengruppe"[159] (Reconstruction Credit Institute) provides a credit program for renewable energies. The KfW has co-financed around 80% of wind farms installed in Germany.[160] The KfW Renewable Energy Programme offers a long-term and low-interest loan with a fixed interest period up to 20 years including a repayment-free start-up period of up to three years. The KfW has set an upper limit for credits for investments in onshore wind which has been increased from €10m to €25m in 2012.[161]

### *Grid access*

In Germany, renewable generators are connected to the grid as a priority and are granted priority dispatch to the grid.[162] Renewable generators have to bear the

---

156 In 2011 almost 30% of the wind generation did not receive FiT, mainly due to direct marketing in connection with the green electricity privilege, The green electricity privilege has been limited to a reduction of €20/MWh in the latest update of the EEG in 2012 (§39) and is not expected to play a major role in the future.

157 §37 EEG (2009), §39 EEG (2012).

158 IEA Wind (2012), *Annual Report 2011* and BMU (2012), *Innovation durch Forschung – Jahresbericht 2011 zur Forschungsförderung im Berreich der erneuerbaren Energien.*

159 The KfW is fully owned by the German state. It acts as a second-tier bank and offers no customer deposits. It refinances its loans on the capital market where it has a AAA-rating due to the state guarantees.

160 http://energiewende.kfw.de/erneuerbare_energien_ausbauen.html

161 http://energiewende.kfw.de/foerderbeispiele.html

162 §5 EEG (2012).

connection costs (including metering devices) to the nearest (or technically and economically most suitable) grid connection.[163] Connections costs in Germany are reported to be slightly above the European average.[164] The average grid connection lead time of approximately 6 months is among the shortest in Europe.[165]

## Planning and community benefits

The building permit and application process in Germany was estimated to take an average of 30 months in 2010, among the lowest in Europe and significantly below the EU average of 42 months. In past years public acceptance rates have declined for onshore wind, in particular in the Northern states with high wind penetration.[166] This has led to a recent increase of cooperatives with participation of the local inhabitants. The number of newly founded cooperatives has increased from two in 2006 to 111 in 2011.[167]

163 §5,13 EEG (2012).

164 EWEA (2010), *Administrative and grid access barriers to wind power.*

165 EWEA (2010), *Administrative and grid access barriers to wind power* .

166 http://www.foederal-erneuerbar.de

167 BWE (2012),Windenergie in Bürgerhand.

# Annexe 4: Ireland case study


## Summary

Ireland has achieved a high share of electricity from onshore wind (16%) with major growth in capacity of over the past decade. This REFIT scheme, which provides a floor price for onshore wind and other renewables, has underpinned this growth.

Support levels and levelised costs have been lower than the UK. The lower levelised costs are explained by higher load factors and slightly lower estimated capital costs, operating costs and cost of capital.

In recent year access to finance has been cited as a major barrier to development, as has uncertainty around curtailment of windfarms.


## Context

Ireland imports around 90% of its energy requirements and therefore renewables are attractive as a route to greater energy independence. Under the EU renewables target Ireland must meet 16% of total energy demand from renewables by 2020. To meet this, Ireland is aiming to meet 40% of electricity demand from renewables by 2020. This is estimated to require 3,521 MW of wind (the large majority of wind is expected to be onshore)[168].

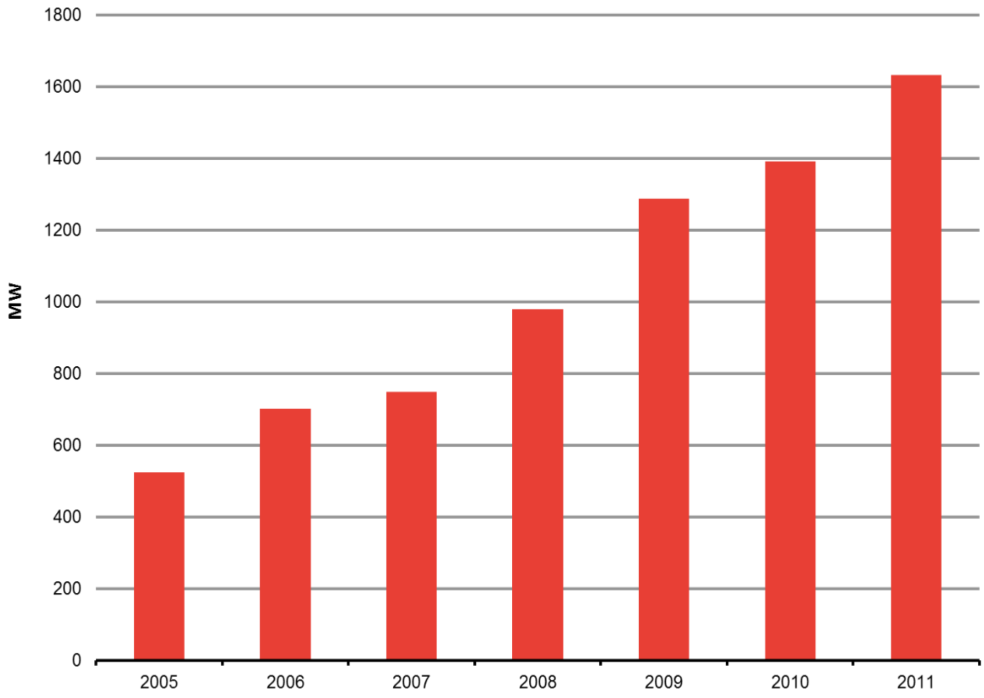
In 2011, 1633 MW of onshore wind was installed in Ireland, meeting around 16% of electricity demand[169]. 240 MW of onshore wind capacity was added in 2011.

The high wind penetrations and islanded nature of the electricity system in Ireland are creating significant challenges in balancing the variability of wind. Wind has represented 50% of demand at certain times. Grid developments such as the recent build of a new interconnector to Great Britain (the 500 MW East-West interconnector) are helping to address this.

168 DCNER (2012), *NREAP First Progress Report.*

169 IEA Wind (2012) *2011 Annual Report.*

**Figure 38.** Installed onshore wind capacity in Ireland (MW)




Source: Eirgrid

There appears a reasonable level of public support for onshore wind. Although there is little recent evidence, a 2003 survey by the Sustainable Energy Agency in Ireland found that over 80% of the public thought that wind energy was a "good thing" and two thirds of Irish adults were favourable to having a wind farm built in their locality[170].

## Main support scheme (s)

### *Current situation and support scheme design*

Since 2006 the main support scheme for wind in Ireland has been the Renewable Energy Feed-in Tariff (REFIT).

Under REFIT, the electricity retail suppliers agree to purchase all of the output from a generator under a 15-year Power Purchase Agreement. The suppliers are then entitled to payments according to the difference between the reference price and a market benchmark which reflects the total market revenues for wind generators (including capacity payment). This works as a 'one way' Contract for

170 SEAI (2003), *Attitudes Towards the Development of Wind Farms in Ireland.*

Difference such that the reference price is a floor on revenues but there is no cap if market revenues exceed the reference price. The PPA price offered by suppliers to generators must be at least equal to the REFIT reference price.

In 2011 the reference price for new (and existing) wind farms was 66.35 €/MWh (£57.7/MWh). This reference price increases annually in line with inflation (CPI), if inflation is positive.

In addition, suppliers are also entitled to a balancing payment. This is set to a maximum of 9.90 €/MWh and, in effect, raises the reference price by this amount. It is not, however, linked to inflation[171]. The amount of this balancing payment received by generators depends on their bargaining power relative to suppliers.

The REFIT is funded through a Public Service Obligation (PSO) on final customers.

## History of main support scheme and deployment

Up until 2006, support for renewables had been delivered through the Alternative Energy Requirement (AER), a competitive tendering regime. The AER accounted for 532 MW of onshore wind capacity[172].

In 2006 the AER was replaced with the REFIT scheme. **Figure 39** shows how support levels for new windfarms have developed under REFIT in real terms alongside deployment of onshore wind.

171 Prior to 2010, the balancing payment was simply 15% of the reference price.

172 Devitt, C. and Valeri, L. (2011), *The Effect of REFIT on electricity prices*.

**Figure 39**. Development of absolute support for onshore wind in Ireland under REFIT (2011 prices)


Sources: Frontier, DCNER, Eirgrid

Levels of support have remained very stable while there has been some volatility in deployment rates. Cited reasons for the 2010 drop include the adverse financing environment as a result of the financial and debt crisis along with uncertainties around the treatment curtailment of windfarms (and compensation for this)[173]. Most projects in recent years have been financed by large state-owned utilities (ESB, Bord Gais).

Versions of REFIT have been subject to quantitative limits on the volume of eligible capacity. REFIT 1, launched in 2006 and open for new projects until 2010 had a cap of 1,450 MW of renewable capacity with most of this used by onshore wind. REFIT 2 is intended to incentivise 4,000 MW of new renewable capacity by 2015.

## Costs of wind deployment

### Capital costs

Only one estimate of capital costs in Ireland in 2011 was available. IEA Wind (2012) quote capital costs for 2011 in Ireland of between 1.6 €m/MW to 2.0

173 http://www.energyireland.ie/onshore-wind-the-financing-environment

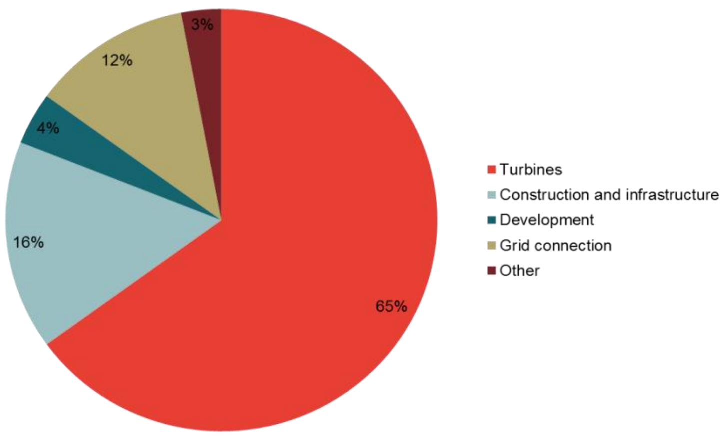
€m/MW for windfarms in the 10 MW range. Of this the turbine costs are estimated to represent 0.9 €m/MW to 1.0 €m/MW[174].

**Table 18.** Central capital cost estimates for onshore wind in Ireland, 2011

| Source | €m/MW | £m/MW |
|---|---|---|
| **IEA Wind (2012)** | 1.80 | 1.56 |

An estimate of breakdown of these costs is provided below in Figure 40. Grid connection costs are a relatively high proportion of costs compared to other countries.

**Figure 40.** Breakdown of capital costs in Ireland




Source: IEA Wind (2012), *Annual Report 2011*

## Operating costs

Very little data has been published recently on operating costs of onshore wind farms in Ireland. A study by ESBI in 2008 estimated operating costs at 51,900

174 IEA Wind (2012), *Annual Report 2011*.

€/MW/year[175]. This translates into approximately 47,400 €/MW/year (£41,299/MW/year) in 2011 prices[176]. Of this value, grid use of system charges represent around 5,000 €/MW/year.[177]

For the purposes of our analysis, we assume a central value of 47,400 €/MW/year with low and high values of 42,700 €/MW/year and 52,200 €/MW/year respectively.

### Cost of capital

Again there is very little published data on the costs of capital for onshore wind in Ireland. An ESBI study in 2008 cites a pre-tax, real WACC of 8%. This is 100 bps above the standard figure used by CER for the WACC of conventional thermal generation.

For the purposes of our analysis we use a central WACC of 8% with low and high values of 7.2% and 8.8% respectively.

### Load factors

Over the past 10 years average load factors for wind in Ireland have ranged from 24% to 35% with an average of around 31%[178]. For new turbines we assume a load factor of 32%, on the basis that new turbine technologies can deliver higher than average load factors, with high and low values of 35% and 29%.

### Levelised costs

The assumptions we use for levelised cost estimates in Ireland can be found in the table below.

---

175 ESBI (2008), *All-Island Grid Study: Renewable Energy Resource Assessment.*

176 Note there was deflation in Ireland over this period. We used the GDP deflator for Ireland to convert into 2011 prices.

177 Eirgrid (2011), *Statement of charges 2011/12.*

178 Eirgrid (2012), *All-Island Generation Capacity Statement 2012-2021.*

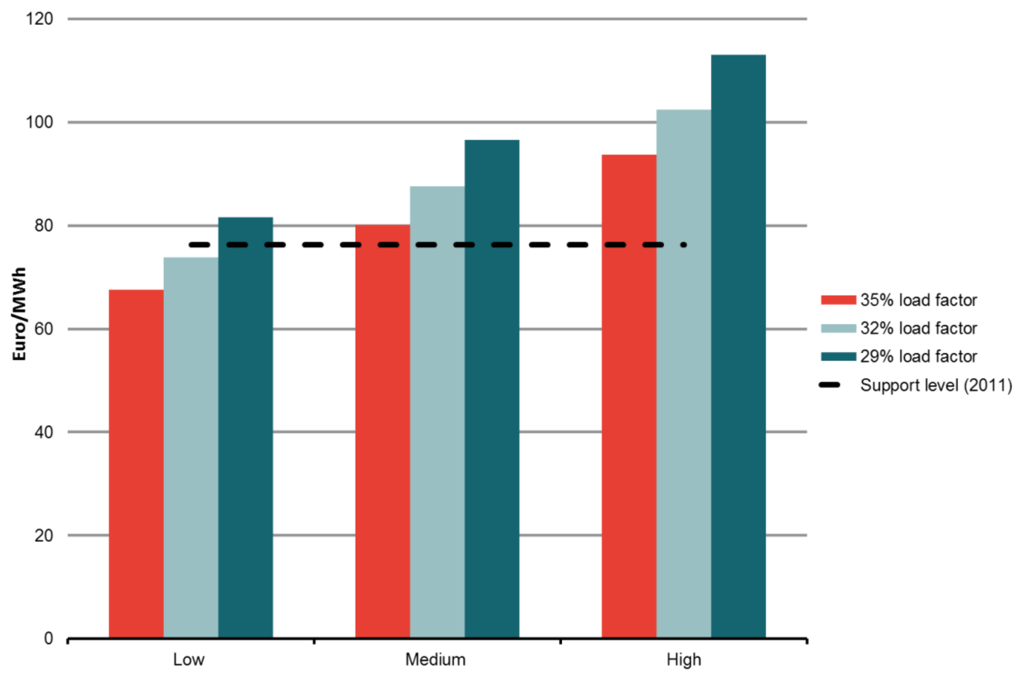
**Table 19.** Assumptions for calculation of levelised costs in Ireland (2011 prices)

| Item | Low | Medium | High | Source/ remarks |
|---|---|---|---|---|
| **Capital costs [€m/MW]** | 1.60 | 1.80 | 2.00 | IEA Wind |
| **Operating costs [€'000/MW/yr]** | 42.7 | 47.4 | 52.2 | ESBI |
| **WACC (real, pre-tax)** | 7.2% | 8.0% | 8.8% | ESBI |
| **Years of operation** | 20 | 20 | 20 | |

Source: Frontier

For each of these cost scenarios we calculate the levelised costs using three different load factors. The results are presented below.

**Figure 41.** Levelised costs of onshore wind in Ireland




Source: Data from various sources, analysis by Frontier Economics

## Other factors influencing deployment

### Other support measures

- **Investment tax incentives.** Companies are allowed to offset the cost of investment in qualifying wind turbines against corporation tax liabilities in year one, thus frontloading cashflows and aiding the financing of projects[179].
- **R&D funding**. Between 2004 and 2010 only around 1% of all energy research funding was for wind energy (around Euro 2m). However, there has been substantial funding (Euro 15.8m) for grid integration research which is seen as a major issue given the isolated nature of the grid in Ireland and the high penetrations of wind[180].

179 IEA Wind (2012), *2011 Annual Report.*

180 IEA Wind (2012), *2011 Annual Report.*

### *Grid access*

Renewable generation does not have priority access to the grid in Ireland. Lead times to obtain grid access appear to be a major barrier to deployment in Ireland. In 2010 the average lead time to obtain grid access was estimated at 31 months compared to and EU average of 26 months[181].

### *Planning and community benefits*

Obtaining consent for build in Ireland takes an average of 33 months compared to an EU average of 43 months[182].

181 EWEA (2010), *Administrative and grid access barriers to wind power* .

182 EWEA (2010), *Administrative and grid access barriers to wind power.*

# Annexe 5: Netherlands case study

## Context

The Netherlands has a very high population density limiting the space for wind. Despite this over 2000 MW of onshore wind capacity is installed and 4% of demand is met from onshore wind.

Since the introduction of the SDE, a FiT (CfD) scheme, deployment of onshore wind has slowed. This may be explained by disruption of changing regime and the scheme design where there is a limited budget for contracts which are allocated on a "first-come first served basis". This may have deterred spend on development while many projects have been awarded contracts but not yet been progressed.

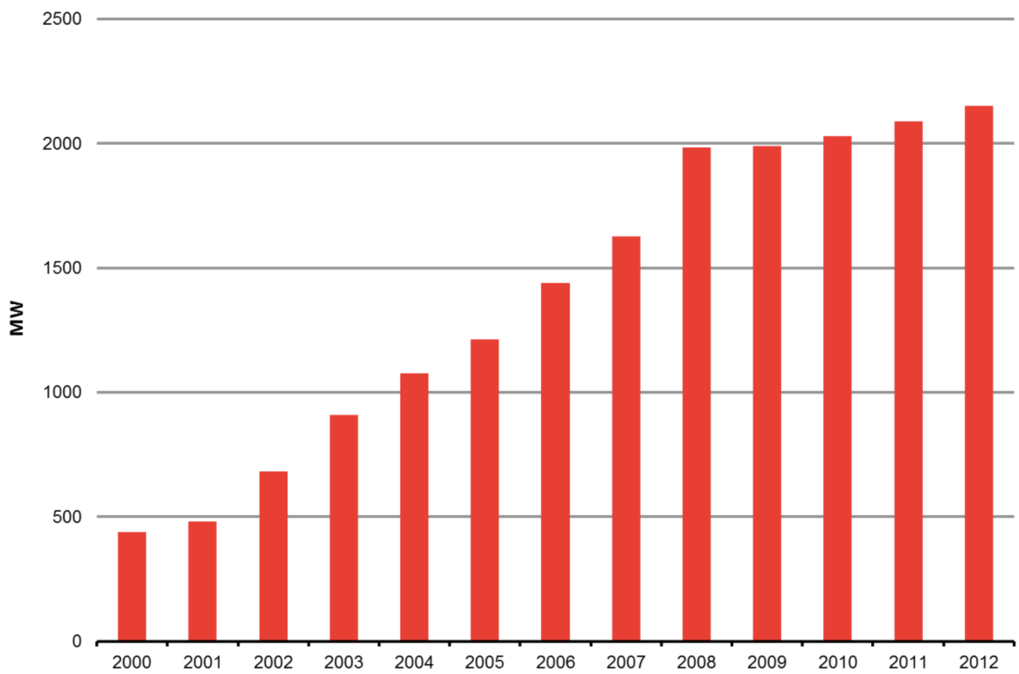
The estimated costs of onshore wind in Netherlands are lower than the UK. In particular, capital costs.

## Context

Under the EU renewables target, 14% of final energy demand in the Netherlands must be from renewable sources by 2020. This is estimated to require 6 GW of onshore wind. However, the current Labour-Liberals government targets 16% of final energy and the budget for SDE has been increased since this new coalition came in power.

In 2011, there was 2,100 MW of onshore wind capacity installed, meeting around 4% of annual electricity demand.

**Figure 42.** Installed onshore wind capacity in the Netherlands (MW)




Source: thewindpower.com. Statistics adjusted to remove offshore wind

An important feature of the Netherlands is the very high population density. This puts constraints on the available land for wind development. A large majority of the public (84%) favours a spread of turbines across various locations (within industrial zones and existing infrastructure in particular, and to a lesser extent in agricultural areas) opposed to concentrations of wind parks at the most efficient locations[183]. The latter has raised substantial objections from the local populations, as has been the case for the largest onshore wind park so far near Urk[184].

The general public is supportive of wind energy, according to research of Blauw research conducted in October 2011[185]. As illustrated by Figure 43, most people have a positive outlook on solar, wind and hydro energy, while attitudes towards biomass, gas and oil are more neutral. Nuclear power and coal are least favoured and a significant proportion of the population opposes these energy sources.

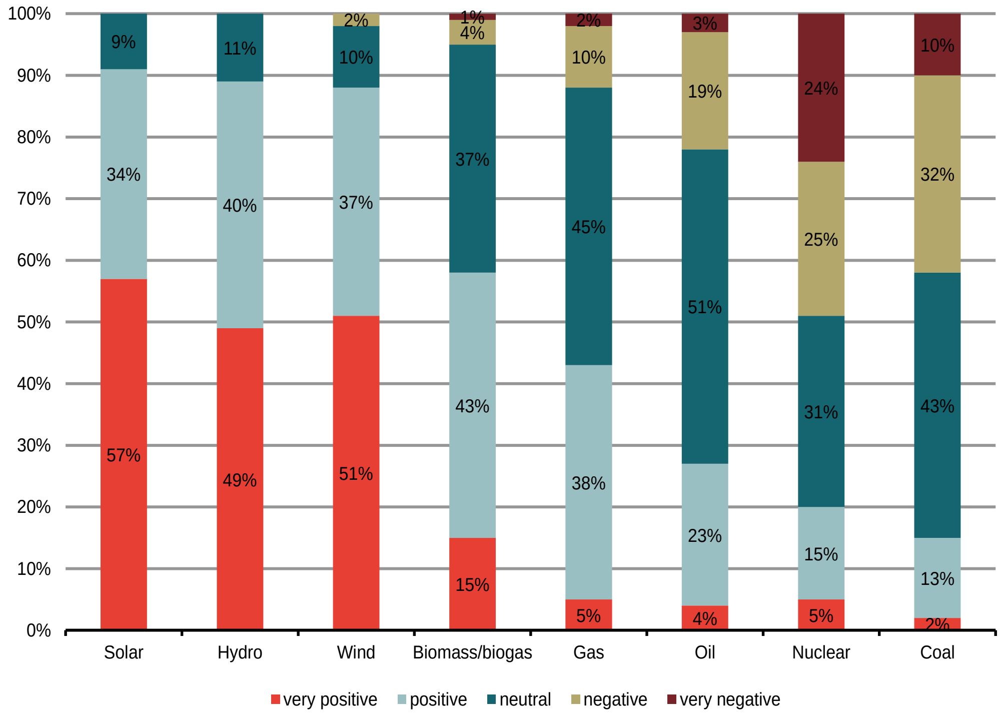
---

183 http://www.windenergie.nl/sites/windenergie.nl/files/documents/burgerconsultatie_vrom_windmolens-op-land_2010.pdf

184 http://uk.reuters.com/article/2011/11/16/us-dutch-wind-idUSTRE7AF1JM20111116

185 http://www.windenergie.nl/sites/windenergie.nl/files/documents/quintel_-_bewustwording_energietransitie1.pdf

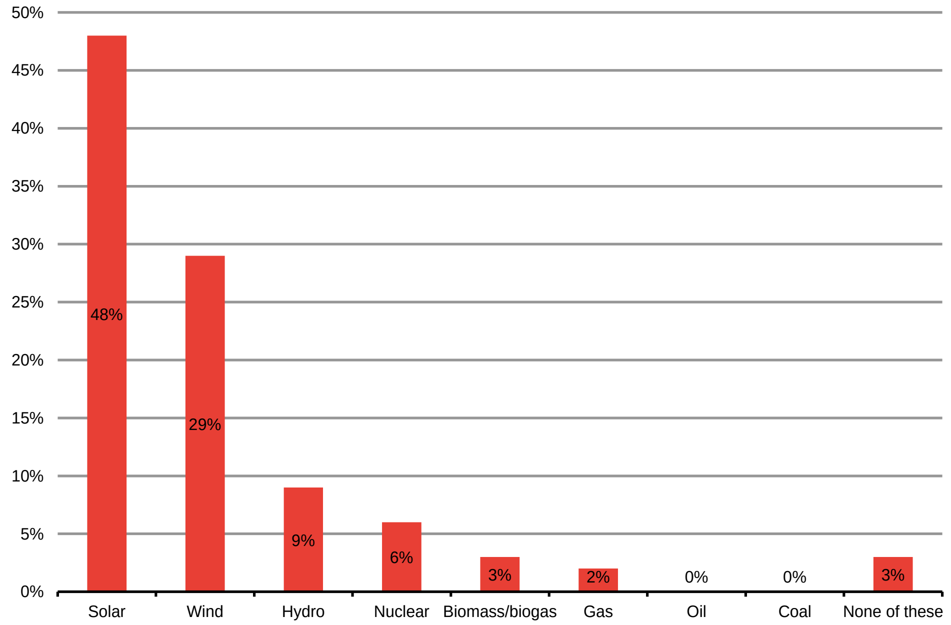
**Figure 43.** What is your outlook on the various technologies?




Source: Blauw research.

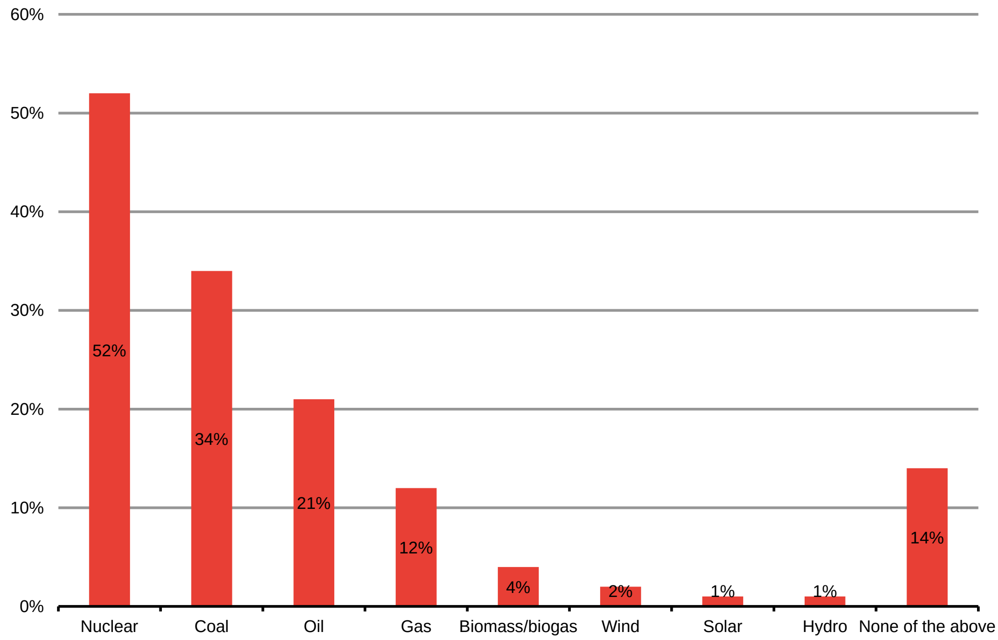
When asked which technology is favoured most, 29% of the population preferred wind (see Figure 44). Only solar energy is seen as the best alternative by a greater part of the public. 2% of the public indicates that wind energy is a technology that should be avoided, compared to 52% disagreeing with nuclear power and 14% believing that none of the technologies should be avoided (see Figure 44).

**Figure 44.** What is your most preferred technology?




Source: Blauw research

**Figure 45.** Which technology should be avoided?




Source: Blauw research

## Annexe 5: Netherlands case study

## Main support scheme (s)

### Current situation and support scheme design

Since 2008 the main form of support for onshore wind has been the SDE stimulering duurzame energie (SDE) which provides differentiated subsidies for a range of renewable technologies.

Under the SDE a premium is paid on top of market revenues for wind farms. This premium is adjusted according to the level of market prices to deliver a target price[186] (i.e. target price = market price plus variable premium). In this way it operates as a FiT (CfD) scheme where generators are responsible for selling their power into the market.

Contracts for onshore wind under the SDE are for 15 years and the target prices are grandfathered in nominal terms for the entire period.[187] The SDE has a limited budget so each year contracts are allocated on a “first-come first-served” basis. Once a contract has been awarded, the project must be realised within four years.

In the beginning of the SDE every technology had a reserved budget and the offered target price was constant but different for each technology. In 2011 different target prices for different phases were introduced. Each phase would last for a few months, and the target prices would increase over time. Together with a combined budget for all technologies, this was aimed to promote competition among technologies and investors to enrol in the scheme before the budget was depleted. For example, an entrepreneur that would be able to go ahead with the projects against lower secured revenues is able to apply earlier and therefore have a higher probability of receiving SDE support. However, this favoured some technologies more than others, as biogas/fermentation technologies used 70% of the total budget in 2011[188].

The total budget allocated to onshore wind in the SDE scheme is presented in Table 20. Onshore wind was originally very successful in acquiring budget, although this was mainly caused by an additional budget of €1.3 billion related to the Urk-windpark. The results from later years imply that onshore wind investors struggle to compete with other technologies given the current target prices.

186 This is termed the ‘base amount’.

187 http://www.agentschapnl.nl/sites/default/files/bijlagen/Kenmerken%20per%20technologie%20SDE%202012_0.pdf

188 http://henribontenbal.wordpress.com/2011/07/28/is-de-sde-2011-een-succes-deel-2/

**Table 20.** Budget, capacity and target price onshore wind NL

| | Budget allocated (€ millions) | Capacity equivalent (MW) | Target price € MWh |
|---|---|---|---|
| **2008** | 73 | 46 | 88 |
| **2009** | 1,352 | 466 | 94 |
| **2010** | 932 | 488 | 96 |
| **2011** | 216 | 119 | 96 |
| **2012** | 2 | N/A | 96* |

Source: Agentschap NL, * base case

In 2011 the first phase provided target prices up to 90 €/MWh and the second phase up to 110 €/MWh. Given the assumptions of ECN, this meant that onshore wind investors were expected to bid in the second phase. Nevertheless, any investor able to realize a project for 90 €/MWh would be able to apply earlier within the so called 'free category'. The 2011 SDE budget[189] was exhausted in phase one so the latter phases were not undertaken[190]. Only wind projects applying within the first phase free category were thus successful, although it remains to be seen if these projects will actually be realized within four years.

In 2012 different targets prices for onshore wind were used within each category, driven by different assumptions on wind conditions. The target price within the first phase was 70 €/MWh. Only one project applied for the €2.3 million budget. This was successful. The second phase had a target price of 90 €/MWh and 28 projects applied for a total budget of €363. However, the total budget was exhausted after phase one and phase two projects have not received SDE subsidies.

Generators are paid the subsidy over 80% of the expected yield (2,200 full load hours), with the payments above accordingly increased by a factor of 1.25 (= 1/0.8). This means revenues are only impacted if load factors drop more than 20% below normal, to below 1,760 full load hours. This helps reduce the risk around load factors for wind farms.

The SDE has been funded from general government budget rather than consumer bills. However, from 2013 funding will come from bills.

189 This is a total budget of 1.5 Euro billion over the course of the contracts of which 9% is allocated to onshore wind.

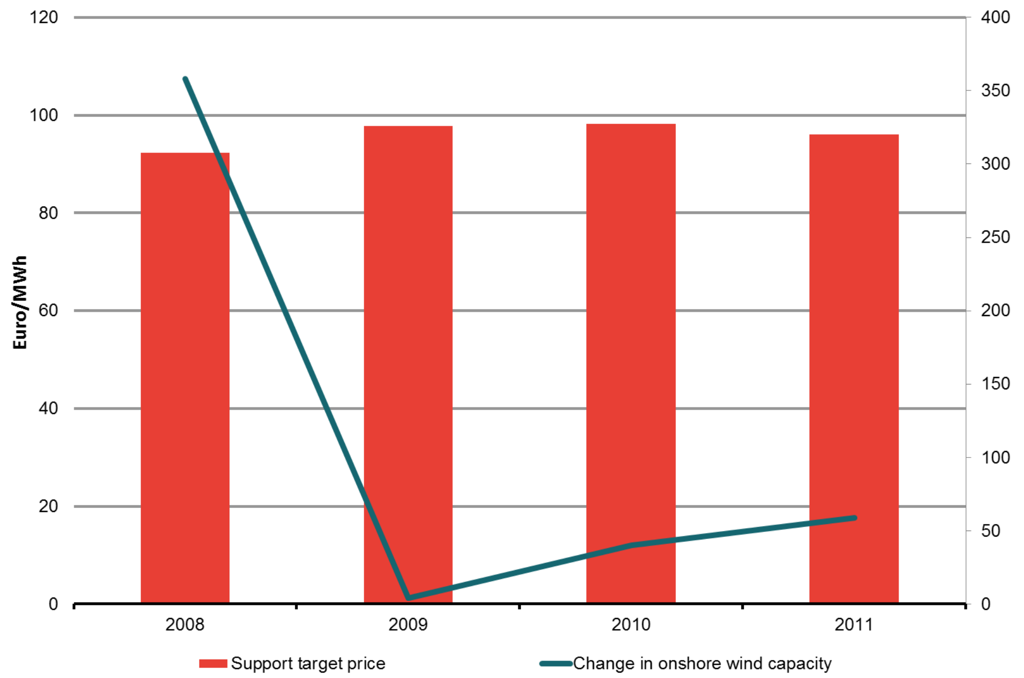
190 IEA Wind (2012), *2011 Annual Report.*

## History of main support scheme and deployment

Prior to SDE the MEP support scheme, a PFiT scheme, was used between 2003 and 2006. This provided premium payments that were differentiated by technology. The take up for the MEP scheme was strong and the scheme was removed partly because of concerns around the rising impact on consumer bills and confidence around meeting the EU renewables target.

As Figure 46 shows, deployment of onshore wind has been limited since the introduction of the SDE in 2008. This reflects the fact that the previous MEP scheme closed in 2006 and that new projects under the SDE could not reach financial close and begin construction until after they were sure they had received a contract under the "first-come first-served" system.

**Figure 46.** Development of absolute support for onshore wind in the Netherlands under the SDE (2011 prices)




Source: Data from various sources, analysis by Frontier Economics.

## Costs of wind deployment

### Capital costs

The following estimates for capital costs in the Netherlands are available.

- In calculating the tariffs for the SDE, the Netherlands research institute, **ECN**, estimated capital costs of 1,350 €/MW in 2011. 1,040 €/MW represents the estimated costs for the turbine and the other 340 €/MW the remaining costs (a more detailed breakdown is not provided). These estimates are based on consultation with industry[191].

- **Irena (2012)** quote a figure of 1,781 US$/MW in 2010 prices. Translating this into Euros and 2011 prices gives a similar value of 1,374 €/MW.

For the purposes of our analysis we assume a central estimate of 1350 €/MW with low and high values of 1,215 €/MW and 1,485 €/MW respectively.

**Table 21.** Capital cost estimates for onshore wind in the Netherlands, 2011

| Source | €m/MW | £m/MW |
|---|---|---|
| **ECN (2011)** | 1.35 | 1.17 |
| **Irena (2012)** | 1.37 | 1.18 |

## Operating costs

The following estimates of operating costs for onshore wind in the Netherlands in 2011 are available.

- **ECN** (2011). In calculating the tariffs for the SDE, ECN estimated annual operating costs of 50,000 €/MW/year in 2011. This is composed of fixed annual operating costs of 25,800 €/MW/year and variable O&M costs of 11 €/MWh and an assumed load of 2200 hours per year. These estimates are based on consultation with industry.

- **IRENA (2012)** quote operating costs that are equivalent to 55,500 €/MW/year. This is composed of fixed annual operating costs of 26,400 €/MW/year and variable O&M costs of 13 €/MWh and an assumed load of 2200 hours per year.

191 http://www.ecn.nl/units/ps/themes/renewable-energy/projects/sde/sde-2011/

**Table 22.** Operating costs in the Netherlands, 2011

| Source | € | | | £ | | |
|---|---|---|---|---|---|---|
| | Total operating costs [€'000/MW/yr] | Fixed O&M [€'000/MW/yr] | Variable O&M [€/MWh] | Total operating costs [£'000/MW/yr] | Fixed O&M [£'000/MW/yr] | Variable O&M [£ per MWh] |
| **ECN (2011)** | 50.0 | 25.8 | 11 | 43.4 | 22.4 | 10 |
| **IRENA (2012)** | 55.5 | 26.4 | 13 | 48.2 | 22.9 | 11 |

For the purposes of our analysis we assume a central estimate for total operating costs of 52,500 €/MW/year with low and high values of 50,000 €/MW/year and 55,000 €/MW/year respectively.

## Load factors

Under the SDE the expected load factor for new wind farms is assumed to be 25% (2,200 hours) by ECN. In 2011 average load factors were 23% in the Netherlands. For the purposes of the analysis we assume a central load factor for new wind farms of 25% with a low and high value of 23% and 27% respectively.

## Cost of capital

In calculating the tariff rates for the SDE, ECN assumes a post-tax nominal WACC of 6.0%[192]. Based on the corporation tax rate of 25.5%, and an inflation rate of 2% this translates into a pre-tax, real WACC of 6.3%.

ECN base its WACC calculations on a nominal cost of debt of 5.1%, a nominal cost of equity (post-tax) of 15% and gearing rate of 80%. These figures are derived from consultation with industry.

For the purposes of our analysis we assume a pre-tax, real WACC of 8.1% in the central case with low and high values of 7.2% and 8.8% respectively.

## Levelised costs

The assumptions we use for our levelised cost calculations for the Netherlands are shown below.

192 http://www.ecn.nl/units/ps/themes/renewable-energy/projects/sde/sde-2011/. Schwabe et al (2011) quote similar results, most likely as they are derived from the same source.

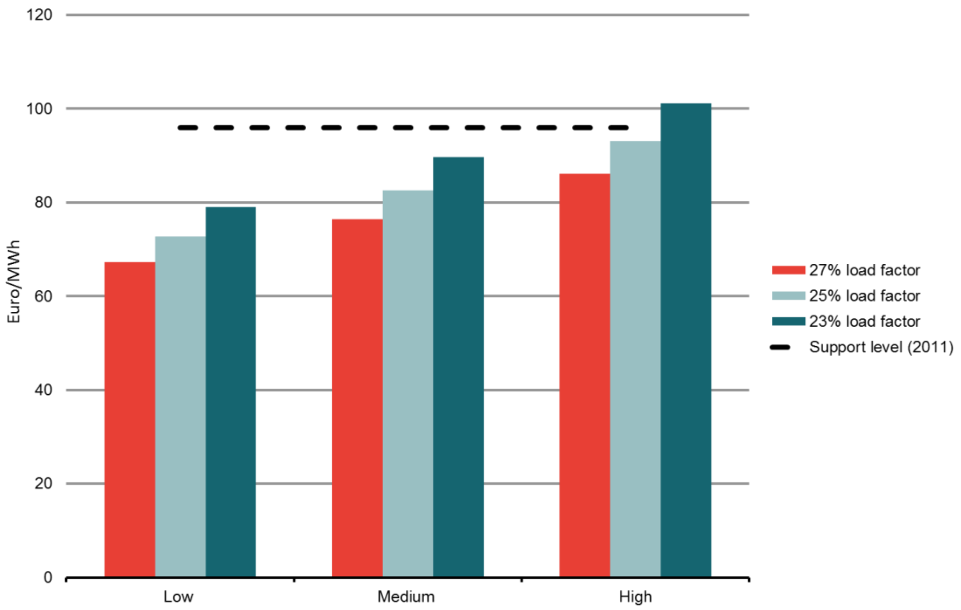
**Table 23.** Assumptions for calculation of levelised costs in the Netherlands (2011 prices)

| Item | Low | Medium | High | Source/ remarks |
|---|---|---|---|---|
| **Capital costs [€m/MW]** | 1.22 | 1.35 | 1.49 | ECN, IRENA |
| **Operating costs [€'000/MW/year]** | 50.0 | 52.5 | 55.0 | ECN, IRENA |
| **WACC (real, pre-tax)** | 5.7% | 6.3% | 6.9% | ECN |
| **Years of operation** | 20 | 20 | 20 | |

Source: Frontier

The range of levelised cost estimates using load factors of 23%, 25% and 27% are shown below in Figure 47.

**Figure 47**. Levelised costs of onshore wind in the Netherlands (Euro/MWh, 2011 prices)




Source: Data from various sources, analysis by Frontier Economics.

## Other factors influencing deployment

## Other support measures

- **Energy investment allowance**. An investment tax benefit enables entrepreneurs based in the Netherlands to write off 41.5% of investments in renewable energy plants against tax in year one. The maximum project costs that qualify for the tax benefit per company are 118 €million per calendar year, the minimum €2,300. This helps improve cashflows at the start of projects although the benefits will vary depending on the profitability of the company[193].

- **R&D**. There a small subsidy streams for wind R&D in the Netherland. In 2010 there was 7.1 €m of support for wind research provided to the Netherlands research institute, ECN and the Technical University of Delft.

193 Ministry of Economic Affairs (2013), *Energy Investment Allowance (EIA) 2013*.

There is also a pre-existing research programme called EOS which funds research into turbine technologies[194].

## Grid access

The process for grid connection appears to be relatively efficient in the Netherlands. In 2010 the Netherlands had an average lead time for grid access of 13 months compared to an EU average of 26 months[195].

## Planning and community benefits

The building permit and application process in the Netherlands was estimated to take an average of 39 months in 2010 slightly lower than the EU average of 43 months[196].

194 IEA Wind (2012), *2011 Annual Report.*

195 EWEA (2010), *Administrative and grid access barriers to wind power* .

196 EWEA (2010), *Administrative and grid access barriers to wind power.*

# Annexe 6: Poland case study


## Summary

Onshore wind in Poland is mainly supported under a quota scheme which does not currently differentiate between technologies. Up to 2011 the price of certificates has been largely set by the buyout price and levels of generation have been less than the quotas set.

The levels of support and the levelised costs of wind deployment in Poland are both relatively high. This is explained the relatively immaturity of the onshore wind industry and low load factors, reflecting difficulties obtaining planning permission and grid access for good sites in the north of the country.

At present uncertainty around the future of the support scheme is discouraging investment.


## Context

Thermal power (mostly coal) accounted for around 97% of generation in 2011[197]. More than half of Poland's coal capacity is over 30 years old and will need to be replaced in the coming years.

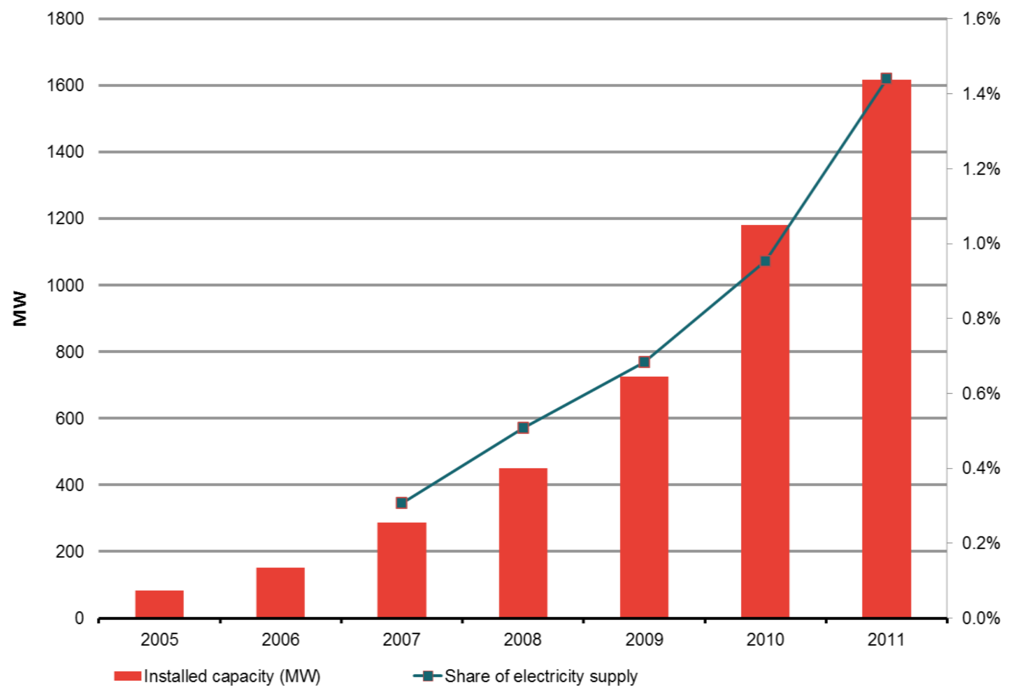
Under the EU renewables target, Poland has a target to meet 15% of energy demand from renewable sources by 2020. As part of this, Poland aims to have 6,650 MW of wind capacity by 2020. By the end of 2011 installed onshore wind capacity had reached 1,616 MW with 2.3 TWh of generation (1.4% of total generation). Public support for onshore wind in Poland is mixed as demonstrated by a recent survey of public attitudes to renewable energy in Poland[198].

---

197 EWEA (2013), *Eastern winds: Emerging European wind power markets.*

198 University of Medicine in Szczecin (2011) *Approval of wind energy and other renewable sources among adult Poles.*

**Figure 48**. Installed onshore wind and percentage of electricity supply met from onshore wind




Sources: EWEA, Energy Industry Regulatory Office

## Main support scheme (s)

### *Current situation and support scheme design*

There are two main elements to renewables support in Poland.

- An obligation on electricity suppliers to purchase wind generation at the mean price of electricity over the preceding year. Going forwards this will simply be a price of 198.9 PLN/MWh indexed to inflation[199] . If generators sell their generation at more than 105% of this guaranteed price they forfeit their right to received certificates for the quota scheme.

- A quota system requiring suppliers to source a defined proportion of generation from renewable sources. They achieve this buy purchasing "certificates of origin" (1 MWh of renewable generation is allocated one

199 Note there are concerns that as this is not linked the average market prices this will lead to wind being undervalued if electricity prices rise faster than the consumer price index.

certificate) or paying a buyout fee ("substitution fee") for any shortfall. This fee has been indexed to inflation but there are plans to remove this indexation going forward. The quota scheme will be in place until 2021 meaning wind farms built in 2011 will receive at least 10 years of support.

At present the quota scheme does not differentiate between qualifying renewables technologies[200] in terms of the level of support. This has resulted in much of the support under the quota scheme going towards low cost options. Between 2006 and 2010 over 50% of the subsidy went to biomass and biomass co-firing, 33% to large-scale hydro and only 13% to onshore wind[201]. However, there are plans to move to differentiated support levels in future[202].

Electricity from renewable sources is also exempt from excise tax which provides a value of approximately 20 PLN/MWh[203].

### *History of main support scheme and deployment*

The quota scheme for renewables in Poland began in 2005. Figure 49 shows how support levels have developed in real terms alongside rates of onshore wind deployment.

---

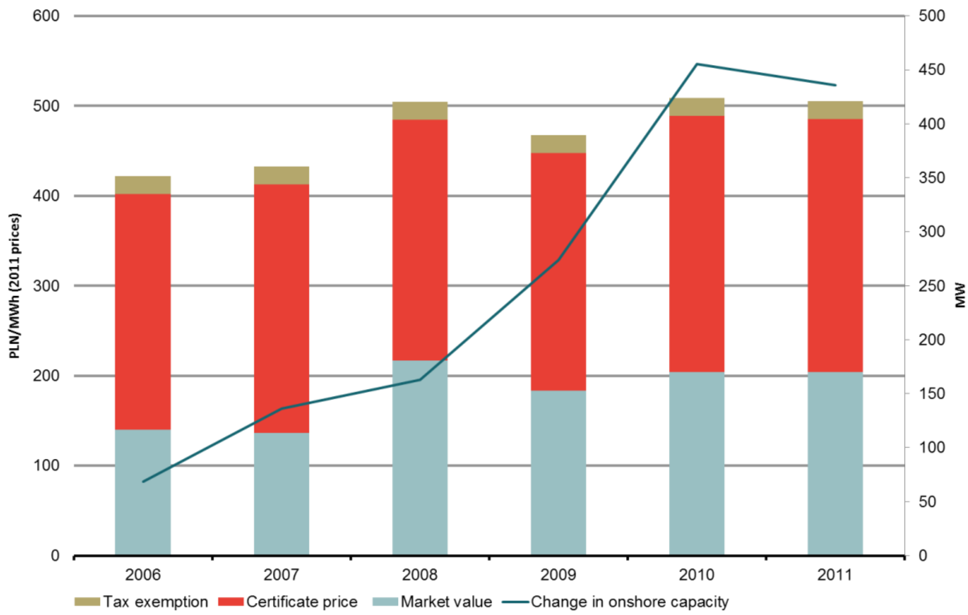
200 Hydro, wind, biomass, biogas, solar and geothermal.

201 Cambridge Programme for Sustainability Leadership (2013), *Clean Energy Finance Solutions: Poland.*

202 In 2013 multiples for larger onshore wind (>500kW) will move down to 0.9 and then further to 0.825 by 2017. For medium scale (200-500kW) the multiple will be stepped up to 1.2 in 2013 and then fall back to 1.125 by 2017. Wind farms smaller than 200kW will more onto a feed-in tariff scheme.

203 KPMG, 2011, *Taxes and Incentives for Renewable Energy.*

**Figure 49.** Development of absolute support for onshore wind in Poland (2011 prices)




Source: Frontier

Up to 2011 the price of certificates has been largely set by the buyout price as levels of generation have been less than the quotas set[204]. The impact on customer bills has been significant with the costs of the scheme estimated to represent 7% to 8% of final bills[205].

The majority of wind farms built in Poland are above 20 MW. Most turbines currently being built are above 2 MW (95%) with 36% above 3 MW[206].

Eight major international turbine manufacturers supply the majority of Polish wind farms (Vestas, Gamesa, GE Energy, Enercon, Fuhrlander, Nordex, Repower and Siemens). Of the biggest five developers in Poland (EDRP, Iberdrola, Vortex, DONG and RWE), four are foreign utilities.

204 Around 15% of the quota target has been met through payment of the buyout fee.

205 Cambridge Programme for Sustainability Leadership (2013), *Clean Energy Finance Solutions: Poland.*

206 In response to a survey, 91% of developers reported that the average project size was above 20 MW. TPA Horwarth (2012), *Wind Energy in Poland.*

## Costs of wind deployment

### *Capital costs*

A survey by TPA Horwath estimated capital costs in Poland to be between 4.4 PLNm/MW and 8.0 PLNm/MW (£0.9m/MW to £1.7m/MW) with a central estimate of 6.0 PLNm/MW (£1.26m/MW). For the purposes of our analysis we use these estimates[207].

**Table 24.** Central capital cost estimates for onshore wind in the Poland, 2011

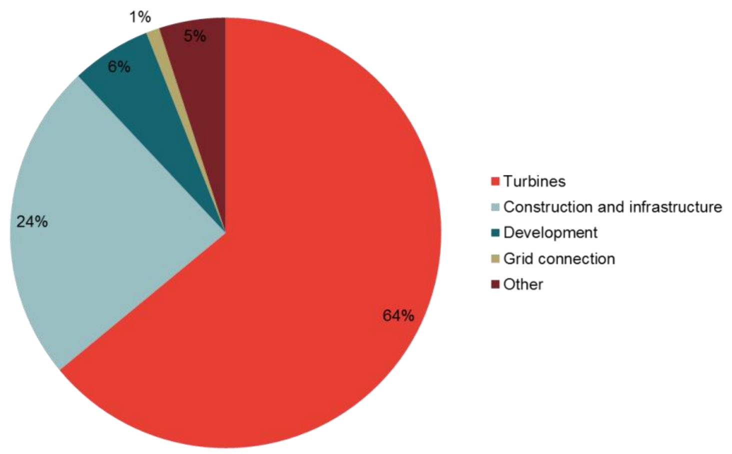
| Source | PLNm/MW | £m/MW |
|---|---|---|
| **TPA Horwath (2012)** | 6.0 | 1.26 |

Figure 50 shows a breakdown of capital costs on Poland. However, we note that there is evidence that connection costs can represent a much larger share of costs that that represented below, with fees ranging from 10,000 to 3,000,000 PLN/MW[208].

207 TPA Horwarth (2012), *Wind Energy in Poland.*

208 TPA Horwarth (2012), *Wind Energy in Poland.*

**Figure 50.** Breakdown of wind capital costs in Poland




Source: TPA Horwath

## *Operating costs*

Based on a survey of industry, TPA Horwath estimate operating costs of 285 PLN/MWh in 2011. At a central load factor of 24% this translates as 598,500 PLN/MW/year (£126,000/MW/year). These are very high costs relative to other countries. Discussion with industry suggests three reasons for this. First, wind farms face a property tax which represents around 15% of operating costs. Second, the O&M supply chain in Poland is relatively immature. Third, many of the sites for wind farms are difficult to access.

For the purposes of our analysis we assume central operating costs of 598,500 PLN/MW/year with low and high values of 540,000 PLN/MW/year and 660,000 PLN/MW/year.

## *Cost of capital*

There is limited evidence available on the cost of capital for onshore wind farms in Poland. A recent report by PWC suggests a pre-tax WACC of 9.6%[209]. This relatively high WACC appears reasonable given uncertainties around the future

[209] PWC (2013), *Analysis of the impact of the proposed RES support scheme changes on wind energy sector in Poland.*

of the support scheme in Poland and that there are risks around the future price of certificates.

For the purposes of our analysis we assume a central pre-tax WACC of 9.6% with low and high values of 8.6% and 10.6%.

### Load factors

In 2011 the average load factor for windfarms in Poland was 22%. TPA Horwath estimate the typical load factor for a new wind farm in Poland of 24%[210].

The best sites for onshore wind are in the North close to the Baltic sea. However, this is also where constraints around planning and grid access are acute. Therefore there has been limited build in these areas.

For the purposes of our analysis we assume a central load factor of 24% with low and high values of 22% and 26%.

### Levelised costs

The table below shows the assumptions we have used for the calculation of levelised costs in Poland.

210 TPA Horwath (2012), *Wind Energy in Poland.*

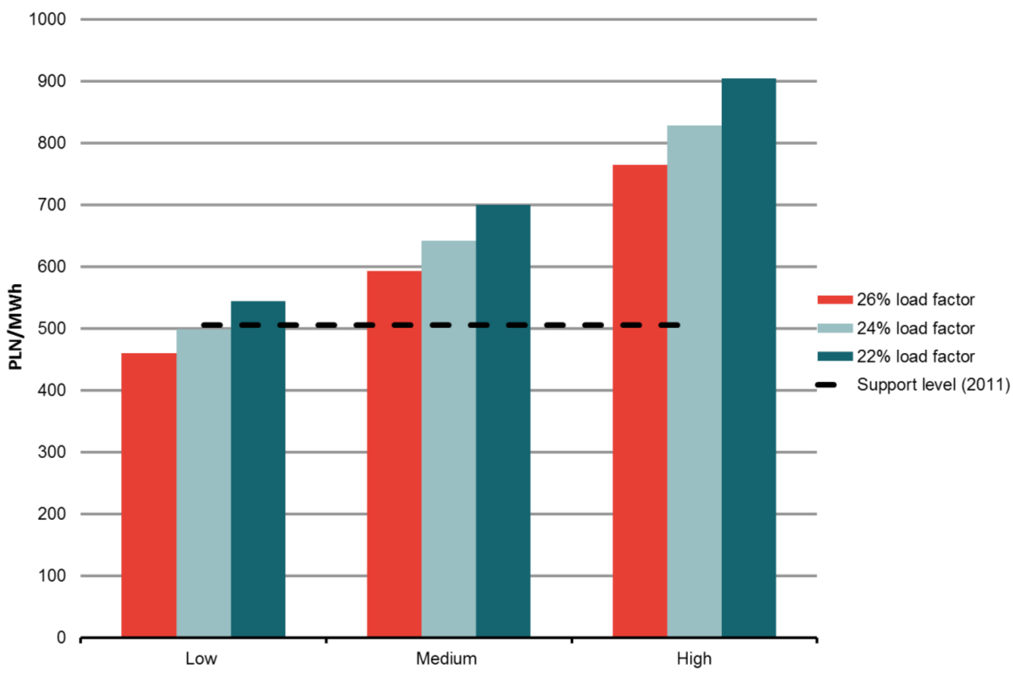
**Table 25.** Assumptions for calculation of levelised costs in Poland (2011 prices)

| Item | Low | Medium | High | Source/ remarks |
|---|---|---|---|---|
| **Capital costs [PLNm/MW]** | 4.4 | 6.0 | 8.0 | TPA Horwath |
| **Operating costs [PLN'000/MW/ year]** | 540 | 599 | 660 | TPA Horwath |
| **WACC (real, pre-tax)** | 8.6% | 9.6% | 10.6% | PWC |
| **Years of operation** | 20 | 20 | 20 | |

Source: Frontier

For each cost scenario the estimated levelised costs are shown below for load factors of 22%, 24% and 26%.

**Figure 51.** Levelised costs of onshore wind in Poland (PLN/MWh, 2011 prices)




Source: Frontier

## Other factors influencing deployment

### *Other support measures*

- **National Fund for Environmental Protection and Water Management**. This fund provides 'soft loans' for renewables projects up to 75% of the project investment costs, including wind farms up to 10 MW. Between 1989 and 2009 the fund helped finance 647 renewables projects with a contribution of over Euro 200m. European structural funds have also been used to finance renewables projects in Poland.

- **Financing of projects from International Financing Institutions**. International financing institutions such as the European Investment Bank (EIB) and the European Bank for Reconstruction and Development (EBRD) are also active in financing renewable energy projects in Poland.

- **Small-scale renewable electricity payment**. Energy suppliers are allowed to collect a payment of 0.6 PLN/MWh from final customers to cover the costs of purchasing energy from small-scale renewables plant at a price above market prices[211].

### *Grid access*

Network companies are obligated to ensure priority connection of renewable energy sources. In 2010 Poland had an estimated average lead time for grid access of 15 months compared to an EU average of 26 months[212]. However, grid access is emerging as a growing risk and barrier to onshore wind investment. An Amendment of the Energy Law for 2012 introduced a non-refundable deposit requirement for grid access. Due to changes in regulation 90% of all ongoing renewable investments lost the legal consents they had previously obtained for grid access and had to apply again[213].

### *Planning and community benefits*

The building permit and application process was estimated to take an average of 43 months in 2010 which is the same as the EU average[214]. However, the lack of transparency in permit regulations has been cited a barrier to project development[215].

211 TPA Horwath (2012), *Wind Energy in Poland.*

212 EWEA (2010), *Administrative and grid access barriers to wind power.*

213 Cambridge Programme for Sustainability Leadership (2013), *Clean Energy Finance Solutions: Poland.*

214 EWEA (2010), *Administrative and grid access barriers to wind power* .

215 TPA Horwarth (2012), *Wind Energy in Poland.*

# Annexe 7: Evidence template

**Country name: Windland**

**Context:**

*All prices/values to be entered in local currency, in 2011 nominal prices*

| | Metric | Notes | Sources |
|---|---|---|---|
| **Total generation and capacity** | | | |
| Total onshore wind capacity (MWs, 2011) | | | |
| Total onshore wind generation (TWhs, 2011) | | | |
| Average load factor (2011) | | | |
| **Main support scheme** | | | |
| Type of support (Quota, FiT, PFiT) | | | |
| Opening and closure of the scheme | | | |
| Total annual support for onshore wind (£m, 2011) | | | |
| Total energy generation supported (TWhs/year, 2011) | | | |
| Total capacity supported (MWs, 2011) | | | |
| Average support level (£/MWh) | | | |
| Range of support levels for new plant (£/MWh) | | | |
| Duration of support (years) | | | |
| Grandfathering and degression arrangements | | | |
| Is supported generation exposed to price risks? | | | |
| Is supported generation exposed to balancing risks/costs? | | | |
| Other restrictions/conditions on support | | | |
| **Secondary support scheme** | | | |
| Type of support (Quota, FiT, PFiT) | | | |
| Opening and closure of the scheme | | | |
| Total annual support for onshore wind (£m, 2011) | | | |
| Total energy generation supported (TWhs/year, 2011) | | | |
| Total capacity supported (MWs, 2011) | | | |
| Average support level (£/MWh) | | | |
| Range of support levels for new plant (£/MWh) | | | |
| Duration of support (years) | | | |
| Grandfathering and degression arrangements | | | |
| Is supported generation exposed to price risks? | | | |
| Is supported generation exposed to balancing risks/costs? | | | |
| Other restrictions/conditions on support | | | |
| **Market prices** | | | |
| Average time-weighted (baseload) wholesale price (£/MWh, 2011) | | | |
| Average carbon price (£/tonne, 2011) | | | |
| **Other support measures** | | | |
| Production-based tax incentives (£/MWh) | | | |
| Investment-based tax incentives | | | |
| Other tax incentives | | | |
| Loan guarantees | | | |
| R&D support | | | |
| Special planning / grid access | | | |
| Other subsidies (£/year, 2011) | | | |

# Annexe 8: Glossary

**Absolute support.** This is the sum of the support received and any market based revenues that onshore wind generators receive.

**Levelised costs**. This is a discounted measure of average costs (on a per MWh basis) which takes into account capital costs, operating cost and expected generation.

**Load factor**. This is the amount of power delivered over the course of a year as percentage of the maximum possible output (i.e. generating at full capacity for the whole year with 100% availability).

**Megawatt (MW)**. This is a measure of the power capacity of a power plant. It is equal to 1000 kilowatts (kW).

**Megawatt-hour (MWh)**. This is a unit measure of the volume of electricity generation and is equal to one MW of power deliver for one hour.

**Net support.** This is the difference between the absolute support metric described above and the value of the wind energy generated as measured by the wholesale price.

**Weighted average cost of capital** (WACC). This is rate on average that an investment must pay back to its debt and equity holders, taking into account the relative shares of debt and equity. The WACC represents the minimum return that an investment must earn to be justified and is used to discount future cashflows

FRONTIER ECONOMICS EUROPE
BRUSSELS | COLOGNE | LONDON | MADRID

Frontier Economics Ltd 71 High Holborn London WC1V 6DA
Tel. +44 (0)20 7031 7000 Fax. +44 (0)20 7031 7001 www.frontier-economics.com