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Comparison of Feed in Tariff, Quota and Auction Mechanisms to Support Wind Power Development

Lucy Butler and Karsten Neuhoff



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Lucy Butler and Karsten Neuhoff¹

1 Introduction

We examine the market-based policies that have been adopted in Germany and the UK to encourage the development of renewable energy sources. Each policy is assessed on the basis of two criteria: the price of power generated and the capacity installed. An analysis of previous experience gives an understanding of the problems encountered in implementing these policies, and the obstacles that prevent the realisation of policy objectives. A comparison of onshore wind is particularly interesting, since although the UK is widely acknowledged to have the greatest resource base, Germany is larger in terms of both installed capacity and generation.

Sawin (2004) provides an extensive survey of renewable energy support policies, and much of our analysis draws on this work. We also refer to other comparisons of wind energy development in the UK and Germany, which have often concluded that the policies adopted in the UK have established a competitive regime and driven down the price paid for wind energy (Klaassen et al, 2003). The Feed in Tariff adopted in Germany does not expose project developers to price competition, and it is assumed that wind power has not been delivered at the lowest possible cost (see Menanteau et al, 2003). We interview developers and assess the impact of competition of wind turbine producers to supply to developers that exists both in Germany and the UK.

¹ We would like to thank Simona Dragosch for conducting the interviews in Germany and David Newbery for helpful comments. The work is conducted as part of the UK research council funded Project SuperGen, Grant RG37889. Contact Lucy.Butler@econ.cam.ac.uk, Karsten.Neuhoff@econ.cam.ac.uk, Department of Applied Economics, University of Cambridge, Cambridge CB3 9DE, UK.

Whilst installed capacity has remained low in the UK, it has increased significantly in Germany. This is often held to be a result of differences in planning system, rather than a result of differences in the market based policies, *per se*. Here we consider whether the UK policy regime has generated a competitive market place for wind energy, and whether the observed decline in prices was a result of this competition. We also consider whether the difference in build rates can be attributed solely to planning regimes, or whether it is a consequence of the renewable support policies.

The policy regime for renewable energy was reviewed and adapted in both Germany and the UK at the end of the 1990s. Given several years of experience, we can make a preliminary assessment of the impact that these new policies have had, and draw a comparison with previous policies. In addition to looking backwards we also look forward and consider the likely effect on the price of wind energy and capacity installed. In doing so, it is important to take the difference in wind resource into account. This analysis is subject to qualification, but does suggest that the price paid for wind energy is already lower in Germany than in the UK, and that this is likely to remain the case over the medium term.

The analysis employs both industry-level and firm-level data. Industry-level data, obtained from a variety of sources, is used to examine the changes in the price paid for wind energy and the growth of capacity in both the UK and Germany. At firm level, we interviewed developers in both Germany and the UK. The interviews investigated the perception of the key obstacles to wind farm development, the level of competition at different stages of the value chain, and financial aspects of development

Section 2 outlines the policy regimes in both countries, and employs industry data to consider performance against the criteria of price at which wind energy was delivered to customers and installed capacity. Section 3 assesses barriers to the development in the UK and in Germany based on firm level data collected during interviews. The aim is to identify whether the rate of commissioning was related to the design of the policy under consideration or to another factor. Section 4 examines the level of competition between developers and other firms operating in the industry, with the objective of determining whether competition was higher in the UK than in Germany, as is often suggested. Section 5 concludes.

2 Policy Assessment

2.1 Background to Policy in the UK and Germany

We give a brief outline of the policies adopted in the UK and Germany. More detailed descriptions are given in Mitchell (2000), in Mitchell and Connor (2004) and in Bechberger and Reiche (2004).

Between 1990 and 1998, the development of renewable energy sources in the UK was supported by the Non-Fossil Fuel Obligation (NFFO). The NFFO was administered as a series of competitive orders in which renewable energy developers submitted bids specifying the energy price at which they would be prepared to develop a project and deliver energy. The Department of Trade and Industry (DTI) determined the level of capacity for different technology bands, and the bids that should be accepted and offered contracts to meet this capacity. The Regional Electricity Companies were obliged to purchase all NFFO generation offered to them and to pay the contracted price for this generation. The difference between the contracted price and the pool selling price, which represented the subsidy to renewable generation, was reimbursed using funds from the Fossil Fuel Levy.²

Following the final NFFO order in 1998, renewable policy was recast in the form of the Renewables Obligation Certificates (ROCs). Eligible renewable generation facilities receive ROCs corresponding to energy produced. (1 ROC being equal to 1 MWh of generation). Electricity supply companies are obliged to buy ROCs corresponding to a fraction of total energy sales, set at 3% of generation in 2002/3. Any electricity company that does not obtain sufficient ROCs has to make buy-out payments (£30/MWh in 2002/3, rising annually in line with inflation). These buy-out payments are recycled to suppliers that have presented ROCs, hence increasing the value of producing renewable energy for competitive generation if the quota is not achieved.

In common with other Green Certificate schemes or Renewable Portfolio Standards, the ROC is based on market principles. Shortage of renewable

² This was levied on electricity bills, and paid by all electricity consumers. The administrative body for this system was the Non-Fossil Purchasing Agency (NPPA), which was set up and owned by the RECs.

generation increases the value of the ROC, thereby encouraging market entry and a decline in the price of renewable energy. The aim is deployment of renewable technologies according to national targets at least cost (see Jensen and Skytte, 2003). The ROC will therefore encourage deployment of the cheaper and better-established renewable technologies unless additional support policies for newer technologies are adopted.

The second basic mechanism to support deployment of renewable energy is the Feed-In Tariff, which was first adopted in California under the Public Utility Regulatory Policies Act (1978). This required utilities to purchase power from 'Qualifying Facilities', especially small renewable generators, at 'avoided cost' rates. These rates, which reflected the marginal cost of acquiring the same amount of energy from an alternative source, were determined by the state utility commissions. Many commissions pegged the rates to high oil prices, resulting in highly favourable guaranteed payment and stimulating renewable development (IEA 2004a).³ A further stimulus to deployment was given by the Investment Tax Credit, implemented in 1979 (Lauber, 2004).

In Germany, the original policy (StreG, Stromeinspeisungsgesetz, 1991) required public energy supply companies to buy power as supplied by renewable generators at 90% of the average price of electricity as charged to final consumers in the previous year. A decline in electricity prices, and thus in payments to renewable generation, prompted the introduction of a fixed tariff, effective from 2000 onwards (EEG, Erneuerbare-Energien-Gesetz, 1998). For wind energy, this tariff was set at 9.1c/KWh for the first five years of operation and for the subsequent 15 years a reduced tariff of 6.19 c/KWh. An allowance is made for the quality of the site, with plants that fail to meet 150% of a reference yield receiving the higher payment for a longer period.⁴ To take account of technological progress and incentivise early investment, the tariffs are reduced by nominal 1.5% for each year the investment occurs after the year 2002.⁵

³ The implementation of PURPA in California was particularly favourable to renewable generation, involving standardised long-term contracts with fixed payments for some or all of the contract term. The deployment of renewable energy was correspondingly high (Sawin, 2004). PURPA remains in place, but the guaranteed prices for renewable generation are currently too low to support deployment (IEA, 2004a)

⁴ This reference site is one with a mean annual wind speed of 5.5m/s at a height of 30m. In the 2003 amendment it was proposed that if a wind plant operator does not prove that the plant will reach at least 65% of the reference yield, the operator is not obliged to remunerate the wind power. Network operators can make transfer payments to correct for non-homogeneous distribution of wind turbines.

⁵ The tariff was subsequently revised to 8.7 c/KWh for the first five years and 5.55c/KWh for the following 15 years. This payment is to decline at a rate of 2.00%.

2.2 Assessing the Success of Policies

This section assesses each of the policies outlined above against the criteria of capacity installed and the cost of energy delivered per installed unit of generation capacity. As wind speeds are higher in the UK, it is cheaper to produce one unit of wind energy (MWh) in the UK than in Germany. However, we are interested in comparing policy instruments, and hence use the degression mechanism provided in the German Feed in Tariff to calculate what would have been the price paid to wind operators within the German feed in tariff had they produced one unit of wind energy in the UK.

2.2.1 Capacity Installed

The success of a policy designed to encourage generation from renewable sources may be assessed in terms of installations deployed. On this criterion, policy followed in Germany may be considered more successful than that followed in the UK. Figure 1 shows installed capacity of wind energy has risen from 48 MW in 1990 to 4500 MW in 2000, when the EEG replaced the StreG (IEA, 2004). Under the EEG, installed wind capacity rose to 8700 MW at the end of 2001 and 14,609 MW at the end of 2003 (IEA, 2004). By contrast, installed capacity of wind energy in the UK has remained low, increasing from 10 MW in 1990 to 649 MW at the end of 2003 (IEA, 2004).

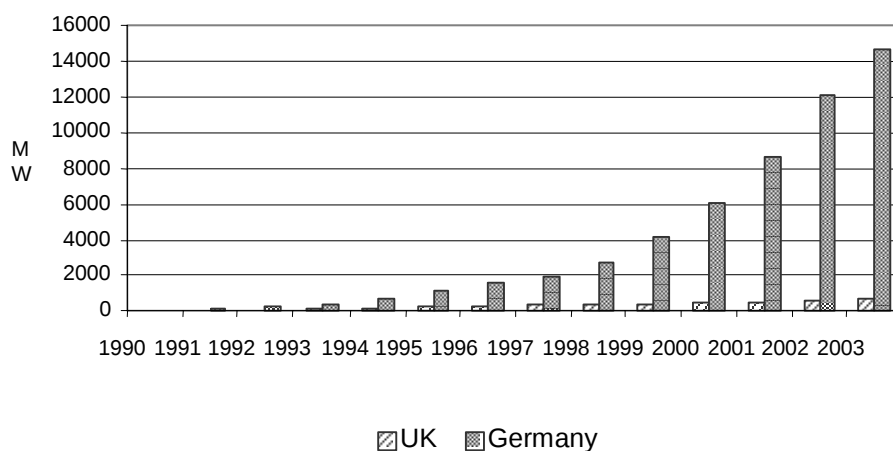


Figure 1: Installed Capacity in Germany and the UK (1990 - 2003)

However, a more appropriate measure of success is not how much capacity has been installed, but how this compares to the targets set for the policy. There was no specific target capacity associated with the StreG, the aim was simply to increase the share of electricity derived from renewable sources (de Vries et al, 2003)⁶. By such a broad definition, the policy can only be considered a success. Figures show an increase in the proportion of net electricity generated from renewable sources from 3.9% in 1991 to 9.11% in 2002, with the majority of this increase accounted for by wind installations (EIA, 2004; IEA, 2004). The target set with the introduction of the EEG was a doubling of the 2000 contribution of renewable sources to reach 12.5% of total electricity generation in 2010. Assuming continuation of current installation rates, realisation of this target is likely.

In 1993, the target for UK renewable generation was set at 1500 MW Declared Net Capacity (DNC) by 2000.⁷ Within each separate NFFO round, the government set a target capacity for each technology, which has not generally been attained. Thus, although the government awarded contracts for 3270 MW of DNC in England and Wales between 1990 and 1998, figures for September 2003 show a DNC of only 960 MW.

The target associated with the introduction of the ROC was 3% of electricity generation from renewable sources in 2002/3, rising in each subsequent year to reach 10.4% in 2010. In 2004, the obligation was extended to reach 15.4% in 2015/16. Most recent figures indicate that 3.24% of net electricity generated was from renewable sources (EIA, 2004). This represents only a small increase on the 2.86% renewable contribution in 2000.

In terms of both absolute capacity, and capacity compared to stated target, the German feed in tariff has been more successful than the NFFO. The introduction of the ROC has yet to generate substantial increases in capacity, with only 60 MW of wind capacity being installed in England and Wales since introduction (BWEA data, July 2004). This finding is reflected in a broader comparison of policy

⁶ Note, however, that there were targets set for reductions in Carbon Dioxide emissions, separately to the EEG. In 1990, the target was set at a 25% reduction on 1987 levels in Energy Related CO₂ Emissions by 2005.

⁷ Broadly, DNC is the equivalent capacity of baseload plant that would produce the same average annual energy output as the renewable energy plant. For wind farms the DNC is calculated by subtracting the on-site electrical power consumption from the installed capacity and multiplying the remainder by 0.43

undertaken by Sawin (2004:8), which concludes that 'feed-in systems have been responsible for most of the additions in renewable capacity and generation' whilst 'the record of quota systems is more uneven'. Similarly, Lauber (2003) and Menanteau et al (2003) conclude that feed-in systems have been more effective in terms of achieving targeted capacity.⁸ Section Three considers whether the differences in installed capacity in Germany and England are the result of these policies, and the other factors that may be of significance.

2.2.2 Price Paid for Wind Energy

Policy may also be judged on the basis of the cost of wind energy delivered. Here we focus on the price paid to wind generators for energy, rather than on the overall cost of support. This overall cost is likely to include network expansion costs and balancing costs, to which wind generators in Germany are not exposed, and which can be separated in the UK.⁹

Policy in the UK is often regarded as having been successful in bringing down prices, whilst that in Germany is criticised as having maintained high prices. However, the introduction of degressive remuneration under the EEG is likely to have reduced the difference in price (Menanteau et al, 2003). Once the differences in wind resource are taken into account, Sawin (2004) suggests that the price paid to renewable energy under feed-in tariffs may have been lower than under the other policies.

The first part of this section looks at the cost of the NFFO compared to the StreG. The second part considers how the price paid for wind energy in the UK and Germany is likely to evolve under current policy.

2.2.2.1 Price of Wind Energy 1990 - 2000

⁸ Lauber (2004) calculates that Denmark, Germany and Spain account for 84% of installed wind capacity in the EU. Each of these countries has implemented a Feed in Tariff.

⁹ With the introduction of the new electricity trading arrangement in the UK (NETA) wind generators are exposed to balancing costs if their production differs from the announced schedule. Part of this additional cost is caused by the requirement to provide additional flexibility, but exercise of market power and the objective to provide incentives to generators to minimise imbalances increases

Although the NFFO failed to deliver target capacity, it has been considered successful in that it drove the price of wind energy down to levels approaching the pool price. This conclusion is based on the price awarded in the auction, and is rarely adjusted to take account of inflation, or of the lifetime of a wind farm development. Here, we deflate price received according to the RPI and discount at a rate of 8% over a period of 20 years. Weighting bids according to the proportion of contracts awarded in each size category, contracted prices fell from 12.34p/KWh in 1990 to 3.99p/kwh in 1998.¹⁰

To compare the price paid for wind generation under different subsidy schemes we make a number of assumptions. When calculating the average revenue per produced MWh over the project lifetime (20 years), we assume a discount rate of 8%.

The decline in price is less significant once the increase in the length of contracts during which turbines received a subsidised electricity price under the NFFO is taken into account. Figure 2 shows a decline in the real average price of bids from 8.50 p/kwh in 1990 to 3.6 p/kwh in 1998, under assumptions that reflect the expectations of developers at the time of bidding.¹¹ In particular, it is assumed that after the expiry of the initial contract, developers are paid the pool price for electricity, which is projected at 1.5 p/kwh in future time periods.

As a comparison the dashed line in Figure 2 shows the price paid under the German policy environment but scaled according to Figure 4 according to the better UK wind resource. If output is 20% higher, then the price paid per MWh can be reduced by 20% while maintaining the same revenue stream for the project and creating little additional maintenance costs. The German tariff after 2000 is differentiated for different wind resources. The dashed line for that period gives the highest possible tariff (least favourable wind resource) scaled by the ratio between the average German and UK wind resources developed in the year.

balancing costs. To ensure equal treatment we exclude balancing costs from the analysis and focus on the revenue generators receive for their energy after subtracting balancing costs.

¹⁰ Note that this is based on contracted sites, not on sites actually commissioned.

¹¹ In 2003 prices. Prices are weighted to reflect the proportion of bids awarded to smaller installations and the proportion awarded to larger installations.

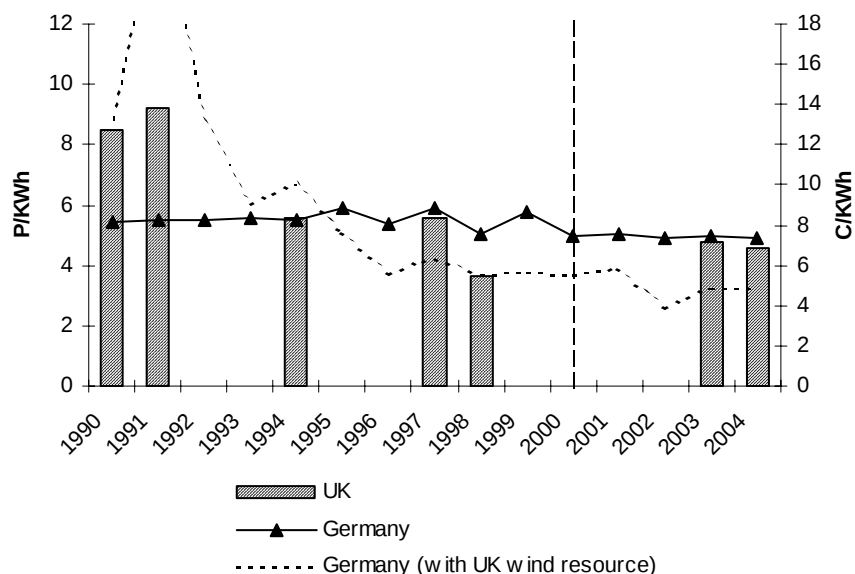


Figure 2: Anticipated Price of Wind Energy in Germany and the UK

The feed in tariff has been criticised for being unduly expensive, with the price of wind energy falling only 18% between 1990 and 1999 (Federal Economic Ministry Advisory Council, 2004) compared to a decline of 67% in contracted prices in the UK.¹²

This change in relative prices has been achieved despite a more favourable wind resource in the UK. Dale et al (2004) quote a typical wind speed of 8.3 m/s in the UK, which compares to a wind speed of 5.5 m/s at the reference location in Germany.¹³ Moreover, evidence from developers suggests that over the latter half of the 1990s sites with a lower wind resource have been developed (see survey data). Given the limited number of coastal locations with a high wind speed, the expansion of wind power has led to the development of sites of lower wind resource. The EEG provided an incentive for such development, since variation in payment compensates almost completely for lower production. The results of this policy are presented in Figure 3, which illustrates that the differentiated feed in tariff in Germany facilitated the development not only of the more windy coastal locations, but also of locations with fewer full load hours per

¹² The price paid under the feed in tariff declined from 18.98 Pfennig/kWh to 17.19 Pfennig/kWh over this period. The cost of support in the UK is given for real average prices, assuming a project lifetime of 20 years.

¹³ Note, however, that this data does not necessarily represent the wind speed at the site of wind farms, since there may be difficulties in securing planning permission or grid connection for the sites where speed is highest.

year (Ragwitz et al, 2004). By contrast, the low contracted prices of the NFFO encouraged early development of the higher wind speed sites wherever possible.

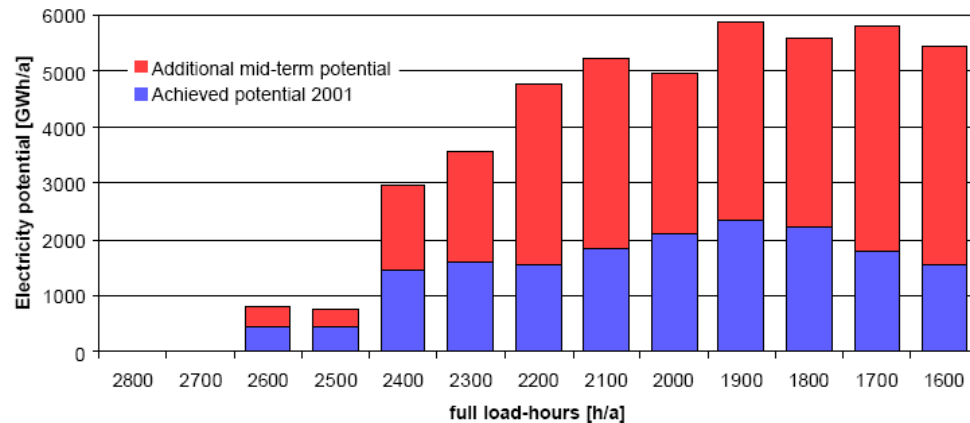


Figure 3: Development of Wind Resource under Feed-in Tariff
(Source: Ragwitz et al, 2004)

Figure 4 illustrates the level of generation (MWh) per unit of installed capacity (MW) over the period 1990 to 2002.¹⁴ This was initially low in the UK due to low turbine ratings at experimental sites, but increased with the increase in turbine rating throughout the 1990s. By contrast, generation per unit of installed capacity has fallen in Germany - this is likely to be the result of developing less windy sites. This situation has been compounded by a drop in average wind speed during the late 1990s (BWE Windenergie 2002). Note also that the increase in turbine rating throughout the 1990s, a result of increasing hub height, has also contributed to the upward trend observed in the UK whilst preventing a further decrease in output per turbine in Germany.

¹⁴ Figures taken for the midpoint of each year, and assuming a uniform rate of build during the year. For Germany, this reaches a maximum in 1994 (2221MWh/MW installed capacity) and a minimum in 2001 (1228 MWh/MW). For the UK, the maximum occurs in 2002 (2681 MWh/MW) and a minimum in 1992 (800 MWh/MW).

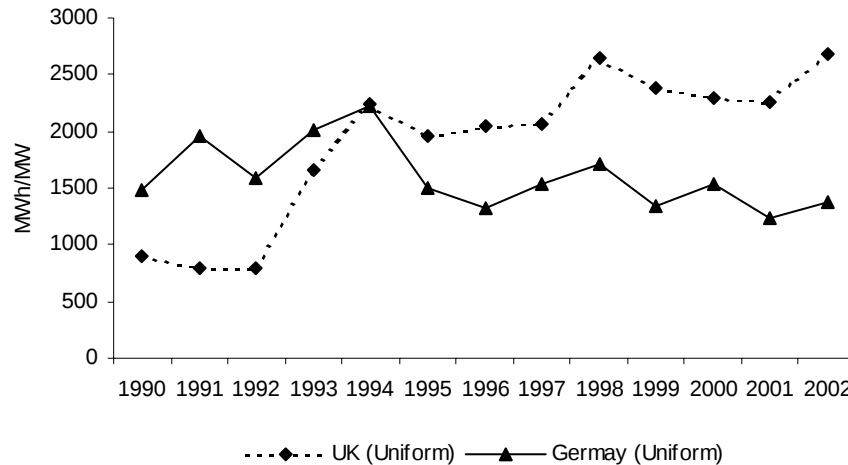


Figure 4: Generation for Installed Capacity (MWh/MW)

Neither the NFFO nor the ROC schemes differentiate between available wind resource at different locations, therefore development of the least favourable location required to satisfy demand will set the marginal price. Since total installed capacity is low, profit-maximising project developers have focused on the locations with a high wind speed. If a successful expansion of wind installations results in development of sites with lower wind speeds, then the increased remuneration required at these locations will set the marginal price, and turbines at locations with higher wind speeds will capture scarcity rents of the high wind locations. If high scarcity rents are to be avoided, a distinction should be made between sites according to the available wind resource. This is recognised in the EEG, where sites of lower wind speed receive higher payment for longer.

Costs of a wind turbine are fixed and only marginally affected by either the resource base or the annual production of electricity. Accordingly, we can make a crude adjustment for output of wind turbines at different locations using the ratio of generation for installed capacity in the UK to Germany as presented in Figure 4. Annual revenue (price received per MWh multiplied by the annual production in MWh) should stay constant when transferring a project between locations with different wind resources. The dashed line in Figure 2 gives the price that would have been required to fund a wind turbine, given the German policy and investment environment but the British wind resource.¹⁵ Making this adjustment,

¹⁵ We assume that the wind farm receives the high payment for the full twenty years of operation.

the price paid to wind generation in the first half of the 1990s is higher in Germany than in the UK, but falls below the UK level in the second half of the decade.

This decline in prices once adjusted for wind output corresponds with the results of a recent survey of German Wind Project Developers by DEWI (DEWI 2002). This shows that nominal prices paid by project developers for wind turbines have decreased from approximately 900 E/kw in 1994 to approximately 820 E/kw in 2001. Inflation adjusted this corresponds to a decrease of 18%. The relative small decrease in the cost of wind turbines is at first sight disappointing, as one might have expected larger cost decreases with the large-scale deployment of wind power. However, Molley (1990) anticipated that with the increase of wind turbine size cost would at best stay constant as the increased turbine size results in a disproportional increase of forces and hence material in the turbine head. The ex-post analysis by DEWI (2002) shows that turbine manufactures compensated for the higher torque moments by increasing the torque moment per kg of material. This allowed a reduction of the weight of the turbine head, which is related to the cost of the turbine head, per unit of installed capacity. From this perspective, significant learning is not reflected in revealed cost decreases but in the ability to provide larger turbines, which make better use of scarce wind sites. Learning by developers, construction companies and other parties in addition to wind-turbine producers may also occur as capabilities are strengthened and development knowledge is acquired. Mitchell (2000) suggests that the infrequent bidding intervals of the NFFO limited such learning effects.

The trends illustrated in Figure 2 raise the question whether the price paid for wind power under the later rounds of the NFFO was viable over the longer term. In particular, the price cited is the average of all bids submitted and does not indicate whether installations have been built. It is possible that the lower priced bids (and some of the higher priced bids) were not economically viable, and have not been built for this reason. Survey data indicates that whilst all developers found NFFO rounds 1 to 3 profitable, only 60% of developers found NFFO 4 profitable and only 40% did likewise for NFFO 5. Those that indicated that these later rounds were unprofitable cited cost considerations as an impediment to development, or relied on parent companies to support development.¹⁶ To suggest that the low prices contracted under the later rounds of the NFFO

¹⁶ In contrast, all of the companies interviewed in Germany indicated that their developments were profitable. Furthermore, none of the companies interviewed were dependent on support from a parent company.

represented the true cost of wind energy might be misleading.¹⁷ Accordingly, the conclusion that the NFFO has been more successful than the Feed in Tariff in bringing down the price of wind energy should be subject to further examination.

2.2.2.2 Price of Wind Energy under Current Policy

Having examined the historical price level, we now consider the price of wind energy under current policies, and how this price is likely to develop. The EEG in Germany provided a digression mechanism that adjusts tariff payments according to the site-specific wind resource. We can use this mechanism to calculate the remuneration an average UK turbine would receive under the EEG. Rather than using the average wind speed in the UK, which may not reflect the accessibility of sites, the speed in the UK was estimated on the basis of speed at existing wind farms. This gives an average wind speed of 7.04 m/s at 25m, which corresponds to 7.22m/s at 30m, compared to a reference wind speed of 5.5 m/s at 30m under the EEG.¹⁸ Given that power production increases non-linearly with wind speed, we assume that a turbine at an existing UK location will achieve at least 150% of the output the same turbine would achieve at the German reference site, which corresponds to the maximum wind speed that is affected by the digression mechanism.

To determine the price paid for wind under the ROC we require the profile of ROC values during a twenty-year period that is determined by the new build in each year between 2002 and 2021. Both because investors in Britain are conservative in their expectations and because we want to get a lower bound to the costs of ROC we choose scenarios that are optimistic about the future deployment of renewables and therefore anticipate a low price paid for ROCs. Following Mitchell and Connor (2004), we break down the value of the ROC into its components, and predict how each of these components will change in future periods. This is illustrated in Figure 5.

¹⁷ In NFFO 5, contracted prices fell as low as 2.43p/kwh for those wind farms with a declared net capacity above 0.995 MW (see Dale et al, 2004).

¹⁸ UK wind speed calculated using the DTI NOABL database.

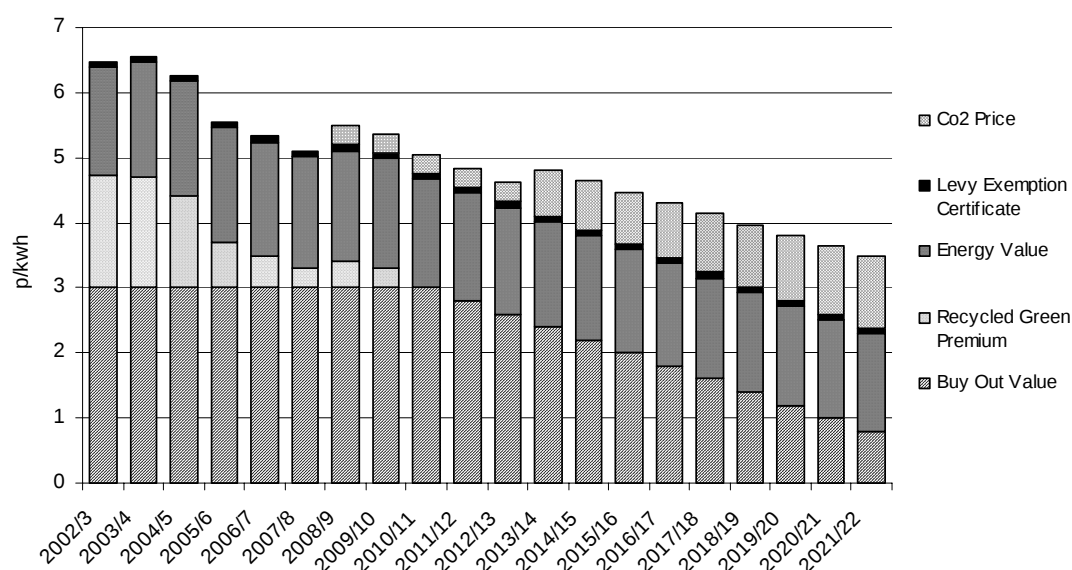


Figure 5: Components of the Price Paid to Wind Energy under ROC (2002 - 2021)

The buy-out value of the ROC is assumed to stay constant at £30/mwh until 2010/11, after which it is assumed to fall on a linear basis in line with declining costs of technology. Following Platt's Energy Journal (2004), we assume a high rate of renewable build such that the renewable obligation is met by 2010/11. At this date the recycled premium falls to zero.¹⁹ The value of the Levy Exemption Certificate is assumed to stay constant at 0.086p/KWh.

The price of energy delivered by wind turbines is calculated by disaggregating the bundled price paid in the NFPA auctions. This gives a value 1.66p/kwh in 2002/2003 and 1.76p/kwh in 2003/4, which is lower than the value of energy delivered from less volatile sources. This price is then assumed to decrease linearly to reach 1.5p/kwh in 2020, which is at the bottom end of the range predicted by the Performance and Innovation Unit (2002).²⁰

Finally, the implementation of the European Emission Trading Scheme will increase the (opportunity) cost of electricity generation by fossil power plants.

¹⁹ This is an extremely optimistic assumption, given the rate of build and perceptions expressed in other investor surveys (LEK, 2003). Both indicate that it is unlikely that the 2010/11 target of 10.4% renewables will be attained. The estimates for the value of the ROC, and thus the cost of wind generation, are therefore towards the bottom end of the possible range.

²⁰ Two counterbalancing effects apply here. Energy prices are likely to increase, but increasing penetration of wind energy is likely to increase the wind discount. It is unclear which one of these will dominate.

Based on Keats and Neuhoff (2004) we assume that an initial CO₂ price of 10 Euro/tCO₂ in 2008-12 will increase the wholesale price by 0.3p/kwh. We assume a subsequent linear increase in CO₂ prices to 25 Euro/tCO₂ by 2022, which will increase the wholesale price by 0.8p/kwh.

To calculate a comparable price paid to wind generation under the EEG to the British wind sites we use two approaches. First, we assume that the average wind speed reaches 150% of the reference location in Germany, corresponding to a good wind site. In this case the high tariff is paid for five years, followed by 15 years of the low tariff. Figure 6 shows the average payment over a twenty-year project lifetime for build in a given year.

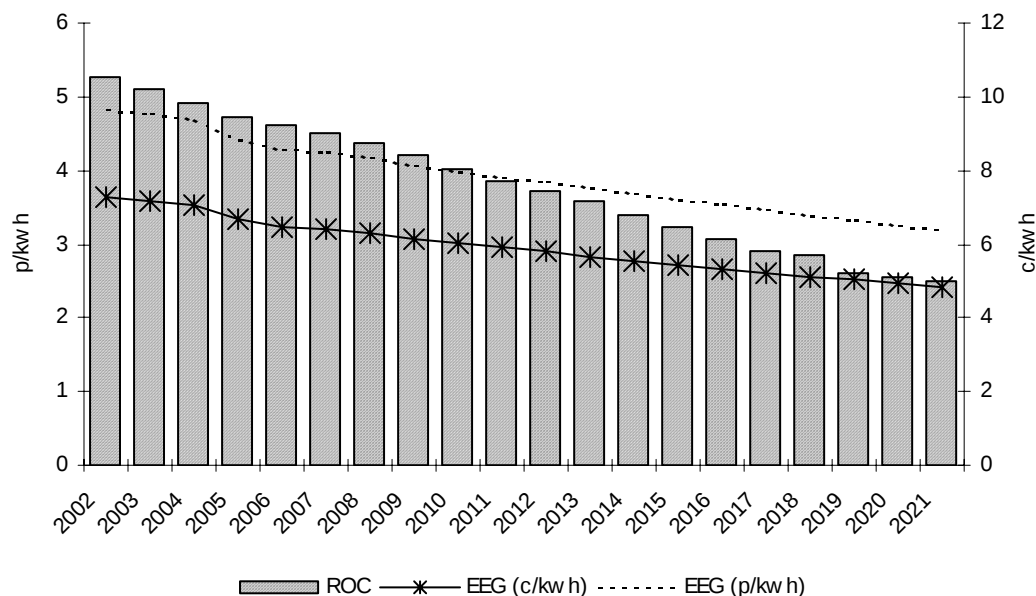


Figure 6: Expected Average Remuneration under the EEG and the ROC

To derive Figure 2, we then assume the price received by a turbine at a very low wind speed site in Germany. The high rate is offered for 20 years. But then we calculate what rate would be required to provide for similar revenue for a UK wind turbine and therefore multiply the price with the ratio of German over UK average hours of wind production per year.

Under the assumptions made and once wind resource has been taken into account, the remuneration provided under the EEG remains lower than the remuneration provided under the ROC until 2012. At this date, the high rate of

build in the UK pushes down the recycled green premium to zero. Under an alternative assumption of a lower rate of build, the remuneration provided under the ROC would remain higher than that under the EEG for a longer period of time.²¹ However, the German parliament can always adjust the premium paid for new projects. It did so in the past whenever it perceived the price paid for wind power exceed the costs incurred by wind power developers.

Since the introduction of the ROC, the premium paid for wind power in the UK has risen to 4.6p/kwh (real prices, over a twenty-year life span). By 2002, the price paid per MWh of delivered wind energy in the UK was roughly equal to the price of wind energy in Germany (see also Mitchell et al, 2004).

Supporting Policies

Although tax credits are frequently used to support renewable investment schemes (see later for a discussion of US policy), no specific tax credits for renewable projects are in place in either Germany or the UK. However, developers in Germany have access to cheap finance through the Deutsche Ausgleichsbank (DtA), a state bank that provides loans on concessionary terms. These loans are currently provided at 0.75% below the market rate (Allerheiligen, 2004) which equates to an increase of 1.8% in the value of the Feed in tariff in 2003. However, in previous years these loans have been up to 2% below the market rate, and may have been a more significant source of support.²²

A number of other policies may also contribute to differences in the price and deployment of wind generation facilities. In particular, the treatment of wind energy in the electricity market is likely to have a significant effect. Under the EEG, electricity is remunerated at a fixed rate regardless of the load profile. In the UK, the New Electricity Trading Arrangements (NETA) place a premium on reliable generation and penalise intermittent generation (for further details see Mitchell and Connor, 2004). This is a particular problem for small independent generators, since such facilities are unable to balance their supply with alternative sources of generation. Similarly, the Spanish Renewable Energy Association

²¹ Oxera (2004) anticipates that the government target of 10.4% renewable electricity in 2010 will be missed by about 2% - the resulting buy-out premia would increase the ROC value to about 38£/MWh.

²² Given the relatively high cost of the less mature technologies, greater levels of support are required if deployment is to take place. A range of policies to support solar energy has been introduced in Germany, amongst which is the payment of a higher rate under the feed in tariff. See Bechberger and Reiche (2004) for further details.

recently observed that requiring wind generators to predict output imposes an unreasonable cost on small operators since it demands costly investment and penalises errors in prediction (APPA, 2004).

2.3 Policy Assessment: Conclusion

We conclude this section by summarising the record of each policy in terms of capacity installed and cost of energy delivered. We first consider previous policies, and then assess the policies that are currently in operation.

Under the NFFO, there was only a limited increase in capacity, with the larger part occurring in early rounds. Although the average contracted price fell to a very low level, this price cannot necessarily be regarded as representative since a large fraction of the contracted projects were not developed. By contrast, the StrEG supported a much larger increase in capacity. Furthermore, when the difference in wind resource is accounted for, it would appear that the price for wind power development is lower than frequently suggested.

Looking forward, the EEG may be more cost effective than the ROC. However, a more conclusive assessment requires that the policy be reassessed at a later date. The Texas Renewable Portfolio Standard (RPS) exhibits initial success, with targets for 2005 met several years early and generation contracted for less than 3c/kwh (Langniss and Wiser, 2003). However, these results are dependent on a range of conditions that will not necessarily be met in future years. In particular, power suppliers have been willing to sign long-term contracts for 10-25 years since the cost of wind generation is comparable to that of new natural gas facilities. Such low costs are driven by a combination of high wind speeds and payment of the federal production tax credit (PTC).²³ Lauber (2004), for example, suggests that the high rate of deployment can be attributed to the near-term expiration of the policy, which gave suppliers the incentive to bring projects on line as soon as possible.²⁴ It would therefore appear unlikely that the rate of deployment can be sustained under the RPS alone.

²³ The PTC was created under the Energy Policy Act of 1992, and comprised an income tax credit for each kWh of electricity produced by wind energy installations built before the credit expired. The value of this credit reached 1.8c/kWh in 2003, and was paid for the ten years following build. The PTC expired at the end of 2001, but was renewed in 2002 before expiring again at the end of 2003 (AWEA, 2003).

²⁴ As with the NFFO, a criticism of the PTC was that it encouraged stop and go cycles of development (IEA, 2004a).

The deployment of renewable technologies is likely to depend on a range of instruments (see Sawin, 2004). The growth of wind power in Germany was supported in the main through the Feed in Tariff, but other policies were also important. Similarly, the growth of wind energy following the implementation of PURPA was partly related to the investment tax credit.²⁵ Although measures directly related to the deployment of wind energy are important, the wider policy environment should not be neglected. The structure of the electricity market was of significance, as was the decision to phase out nuclear generation (Bechberger and Reiche, 2004). An assessment of both past and future success of the policies adopted to support renewable energy has to take into account such factors (see also Mitchell et al, 2004).

3 Why Regimes Differ in Delivering Installations

We try to assess why the capacity installed in Germany has been significantly higher than that in the UK. We disaggregate the development of a wind project into stages and asked developers to assign a rating to the problems encountered at each of these stages, with 1 representing no difficulties and 5 representing severe difficulties. Since German developers seem to focus more on difficulties, their overall average rating was 2.5 compared to 1.9 for both the NFFO and ROCs in the UK. We depict the deviation of the ratings in individual categories from these country averages (see Figure 6). In addition, developers were asked why proposed wind farms had not been developed to identify the binding constraint.

The most frequently cited obstacle to the development of wind energy in the UK has been planning restrictions (Gross, 2004; IEA, 2004; Sawin, 2004). One explanation is that the successful bids have been for sites with a good wind resource, which are often in exposed locations, making it difficult to obtain planning permission. Mitchell and Connor (2004) observe that the structure of the NFFO has exacerbated the difficulties associated with obtaining planning consent. Wind farms were built at the same time in similar locations, resulting in a high level of opposition to development that persists today.

²⁵ In California, large investment tax credits and long-term contracts led to a rush to install wind turbines, many of which were sub-standard. Although this led to the development of wind generation, the industry collapsed when the policies expired (Sawin, 2004).

The constraint that planning permission represents was confirmed in interviews with developers where it was identified as the most problematic area of development under the NFFO. This remains the case under the ROC, although developers have suggested that the situation is improving somewhat. This is confirmed by data from the BWEA showing a decline in the proportion of capacity that has been refused planning permission (BWEA, 2004).

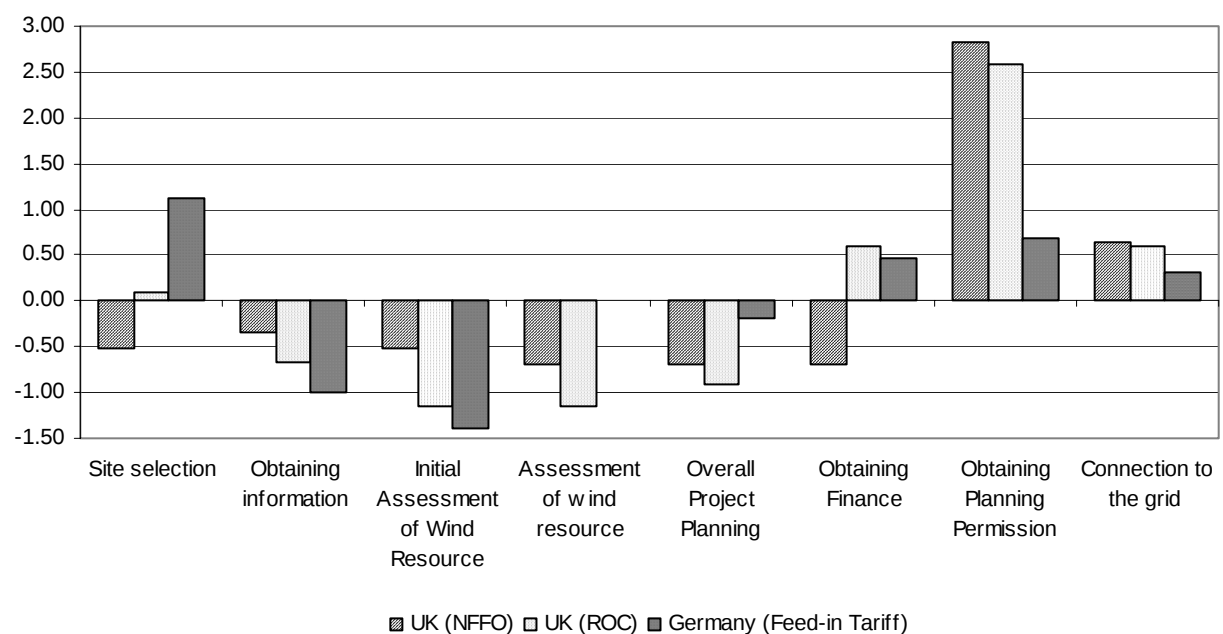


Figure 7: *Obstacles to Development: Relative Assessment by Developers*

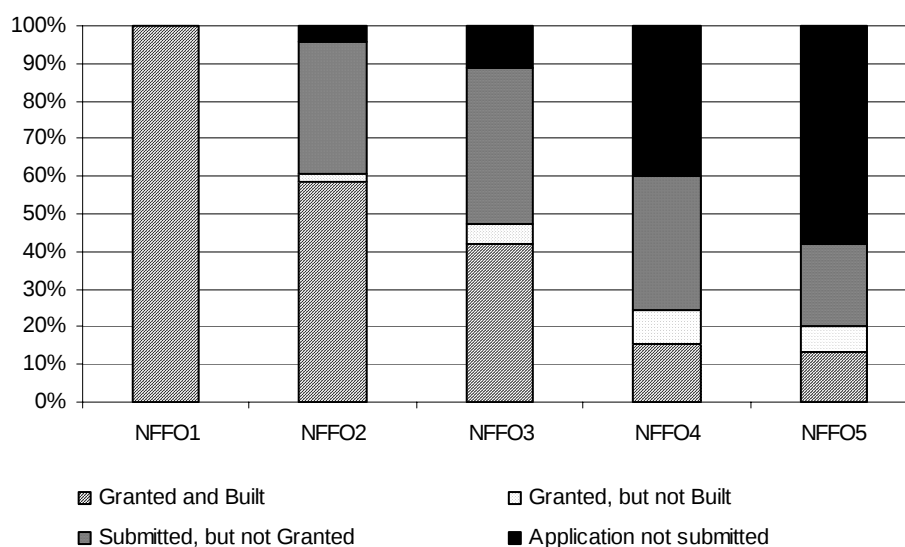
However, data from a range of sources suggests that the difficulties involved in the planning process in the UK may be overemphasised. Skytte et al (2003) report that the average planning time for a wind farm in the UK is approximately two years. The planning process takes a similar period of time in Germany, and significantly longer in Spain where the average time is three years. In neither of these countries does this appear to have constrained growth to the same extent as in the UK.

Skytte et al (2003) also compare the risk associated with wind farm development. Across Europe, obtaining planning permission is regarded as high risk in that it is both important for the investment and unpredictable. Comparing

countries, the process is regarded as slightly more risky in Denmark than in the UK. Despite this, we observe that deployment in Denmark has been significantly higher than in the UK.

Furthermore, interviews conducted with German developers confirmed that difficulties in obtaining planning permission were a constraint on development (see Figure 7). These problems accounted for all of the cases in which a proposed development was not completed. The success of previous policy, which has resulted in high levels of development and a fall in land availability, is likely to be a factor contributing to this constraint. Such a conclusion is supported by the difficulties encountered in site selection, with developers reporting that the lack of appropriate sites is now the most significant obstacle to further deployment (see Figure 7). As a result, further development of onshore wind is likely to shift towards repowering existing locations. Finally, we note that the problems reported may reflect competition between project developers. As availability of appropriate sites declines, landowners are able to negotiate more favourable lease contracts, and in doing so extract increasing fractions of the expected project surplus (see subsequent section on competition).

Consideration of industry data from the UK shows that planning permission does not account for all cases in which development is not undertaken. Figure 8 shows that there have been an increasing number of cases in which planning permission has been obtained, but development has not taken place. There has also been a significant increase in the proportion of developments for which no application was submitted. We hypothesise that cost constraints are likely to play a role in both cases, with several developers indicating that the proposed installations were not economically viable at the bid price.



Source: compiled from various sources (BWEA, Country Guardian, company data)

Figure 8: Planning Status of Projects with NFFO Contracts

However, it is important to recognise the various interactions that take place. Planning permission increases costs, making it likely that the low prices submitted will become even less viable. Moreover, a developer will use less effort to push a project through the planning permission process, if he expects low profitability.²⁶ Similarly, connection charges were cited as one of the aspects that could have a material effect on the viability of a development. An investor survey conducted by LEK Consulting (2003) for the Carbon Trust reached a similar conclusion, suggesting the costs involved in connection and reinforcement can be prohibitive. Difficulties with connection seem to have increased over time, with it being considered more problematic under the ROC than the NFFO.

The interviews suggest that obtaining finance was not regarded as a significant problem under the NFFO, despite indications that the level of competition in the market for finance provision was relatively low (see following section). This result may be dependent on the company structure since almost half of the companies indicated that they had the support of a parent company, making financing easier.

²⁶ Skytte et al (2003) also refer to the French EOLE scheme, under which the average contract price was approximately 4.5c/kWh. Long lead times, partly due to lengthy planning procedures and burdensome administration, rendered any contracts unprofitable. As a result, only 10% of contracted generation was being produced five years after the contracts were signed.

Also of importance was the certainty of payment under the NFFO. Developers indicated that this certainty made financing easier, although the contract was too short in early rounds (eight year) and acceptable contract prices were too low in the later rounds. It is thus questionable whether a competitive tendering process, which places such emphasis on reductions on the price paid for wind energy, is the most appropriate means of encouraging an expansion in capacity.

By contrast, obtaining finance is perceived to be more difficult under the ROC where payments are not guaranteed. Although the price paid under the latter is currently higher than under the NFFO, there is concern amongst investors that the policy will not be continued over the longer term (see also LEK, 2003)²⁷. The financial support provided by the ROC is subject to considerable uncertainty. The value comprises four elements: the price of power, the buyout price, the value of the Levy Exemption Certificate (LEC)²⁸, and the recycled ROCs premium. Each of these is subject to uncertainty, stemming either from policy change or from changes in supply and demand. The recycled premium, for example, was reduced in 2002/3 following the bankruptcy of TXU and Maverick.

Uncertainty can be mitigated by implementing long-term power purchase agreements (Skytte et al, 2003; Helby, 1997). The initial success of the Texas RPS has been attributed to the fact that power suppliers have been willing to sign contracts with a term of 10-25 years (Langniss and Wiser, 2004). However, the RPS would appear to be an unsuitable policy for driving the development of less mature technologies. Although there has been a substantial increase in wind capacity, solar generation remains too expensive to compete with conventional generation even with subsidies (Langniss and Wiser, 2003). Furthermore, the increase in wind capacity is in part dependent on the Production Tax Credit, which enabled wind generators to compete on cost (Lauber, 2004). The high rate of deployment can be attributed to the near-term expiration of the policy, which gave suppliers the incentive to bring projects on line as soon as possible.²⁹ Again, supporting policies are shown to be important in facilitating the deployment of renewable technologies (see also section 2.3).

²⁷ Mitchell and Connor (2004:1944) note that 'the RO – put into place in 2002 and intended to last until 2027 – was being questioned by the White Paper within a year of its inception'. It is inevitable that such political ambivalence will damage the credibility of any policy.

²⁸ Under the CCL, certain major energy users are able to reduce the normal CCL payment (0.43p/kwh on business customers) to 20% (0.086p/kwh) by purchasing renewable electricity.

²⁹ Both the PTC and the NFFO have been criticised for encouraging stop-go cycles of development (IEA, 2004a).

In Germany, as in the UK, the difficulties experienced when trying to obtaining finance depend on the structure of the company. There was the perception that it was getting increasingly difficult to obtain finance for a number of reasons. Investors had been unsettled by long discussion of the EEG and attendant uncertainty. This uncertainty has been compounded by a series of years with wind speeds below the long-term average wind speed. It remains to be seen whether the payment guarantee provided by the EEG is adequate insurance against low levels of generation, or whether financing will become increasingly difficult.

The results of the survey show that in Germany, planning permission (and related political factors) account for all cases in which development did not occur in our survey. As the digression formula of the feed-in tariff facilitates development of lower wind sites, only sites which have low wind-speeds or which are difficult to connect would face binding financial barriers. Such sites are likely to be abandoned in a screening phase, especially given the more stringent conditions proposed in the amendment to the EEG.

In the UK, cost factors were also important, with low prices indicated as having inhibited development. This is particularly the case in the later rounds of the NFFO where many of the bids were based on optimistic assumptions (see also Mitchell and Connor, 2004). The ROC system has the potential to resolve this, since price paid to generation is much higher.

4 Competition under German and UK Policies

The rationale for the structure of the NFFO was that it retained significant elements of the market, whilst providing support for renewable generation. It was expected that competition amongst developers would drive down the price of renewable energy close to the pool price. Section 2 and 3 confirmed that the prices of awarded contracts indeed fell significantly, but that the selected projects were frequently not economically viable. Developers in Germany, by contrast, have not been subjected to the same pressure to submit low prices. Indeed, when prices received for generation began to fall due to declining electricity retail prices, the StreG was replaced with the EEG where tariffs were fixed.

Here we examine whether the perception that the NFFO and the ROC encourage competition and that the Feed in Tariff limits competition is correct. Price competition among developers is only one aspect of competition, and hence we assess to what extent competitive markets within the value chain are relevant and have developed. First, we examine the level of competition between developers under the different policies. Second, we consider the levels of competition between firms providing services related to wind farm development. We find evidence of significant commercial interaction between developers and between other firms operating in the industry.

4.1 Competition between Developers

Under the NFFO auction, the lowest bids that passed an initial examination of completeness and economic viability were awarded contracts. The ROCs scheme in the UK produces some element of competition, in the way that the ROC price is market based, and hence supposed to represent the cost of a marginal wind turbine. In Germany, developers did not bid prices at which they were prepared to develop a site, but were paid a fixed price, related to the retail tariff. Subsequently, the EEG introduced a differentiation based on the local wind resource, but once again, the developers were not asked to compete against each other to develop a project for a lower tariff. However, the Feed in tariff should have encouraged competitive behaviour since it gives developers an incentive to reduce costs in order to increase their margin and profits.

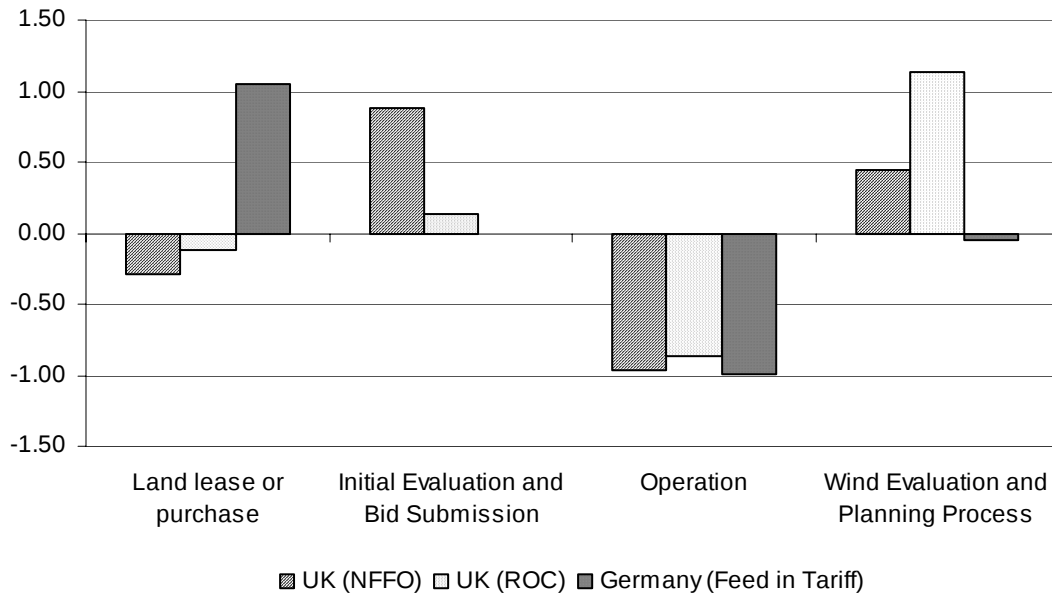


Figure 9: Relative Competition between Developers³⁰

Figure 9 confirms that developers perceive bidding as the most competitive phase of the NFFO process, and encounter little competition at other stages.³¹

Comments from developers indicated that there was significant pressure to submit low bids in the later round of the NFFO. One German developer indicated that they had withdrawn from the UK market due to the severe competition at this stage.

However, Mitchell (1994) questions whether this competition was significant in the earlier rounds. Two thirds of the capacity contracted in NFFO-1 was accounted for by existing facilities and the prices were agreed in advance of the bidding process. Competition increased in the second round when most of the contracts were for new capacity, but is still described by Mitchell and Connor (2004:1936) as 'limited'.

³⁰ Developers were interviewed on how they viewed the level of competition between developers at different stages of wind farm installation. The stages identified as relevant were Land Lease (or purchase), Wind Evaluation and Planning, Operation, and in the UK, Initial Wind Evaluation and Submission. Developers were asked to assign a rating to the level of competition with other developers at each of these stages. These responses were then adjusted to give a relative level of competition

³¹ The average response over all competition questions was 3.1 in Germany and 1.9 in the UK. It is unclear whether the overall level of competition is higher, whether it is perceived to be higher or whether the difference is due to the interpretation by German speakers. Therefore, the graphs only depict the deviation from the average level.

In Germany, the main source of competition among project developers is for sites. This is confirmed by the results presented in Section 3 where site selection was identified as one of the most problematic stages for German developers. Land lease and purchase would not appear to be a significant problem under the NFFO or the ROC, a result that is a consequence of lower levels of development and better wind resource. The increased competition for sites under the German Feed in Tariff is reflected in increasing payments to landowners (developer survey). This competition can also explain some of the success of the German system in obtaining sufficient planning consents for new developments.³² The greater the competition for sites, the more effort developers will apply to convince the local community to accept a wind projects.

The level of competition in operation is not significant in either Germany or the UK. In Germany, the market structure in which operators take over a development does not generally apply. Either developers operate installations themselves, or turbine manufacturers provide the service (Survey data). This stage appears to be only slightly more competitive in the UK than in Germany, again this may be the result of practices in the market. Developers may operate the wind farms, rely on partners to do so, or defer the decision to the owner of the wind farm. The low level of competition in the operational phase of wind projects should be subjected to further research. It is difficult to contract and verify that maintenance is performed to ensure the duration of a turbine life. However, given the increasing future expenditure on turbine maintenance it seems to be worthwhile to contemplate whether a development of this market segment should be facilitated, e.g. by increasing standardisation or provision of information.³³

4.2 Competition in Contracted Industries

Competition among wind project developers to provide wind at lower prices is only one aspect of competition. The ability of project developers to realise projects at low prices depends on their procurement costs e.g. for turbines and construction services. As these procurement costs constitute the majority of the cost of wind projects, we assess competition among turbine producers,

³² Initially support was provided by national legislation requiring communities to identify and make available suitable sites for wind project developments. However, increasingly developers succeed in convincing communities to make additional or better-suited land available.

³³ Currently most operational data of turbines are kept confidential and are frequently only accessible or fully comprehensible by the manufacturer.

constructors and finance providers. We asked developers to assign a rating to the level of competition between companies providing these services. The results were adjusted as for the competition among project developers and are presented in Figure 10.

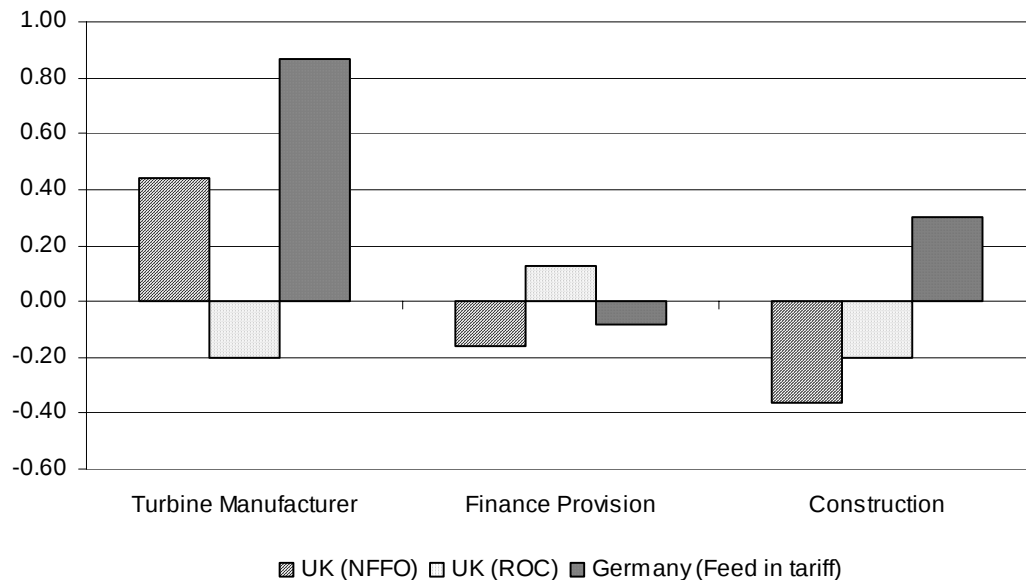


Figure 10: Assessment of Competition in Wider Market

There appears to be significantly greater competition in the market for turbines in Germany than in the UK. This result is confirmed by industry data showing that the German market is split between a greater number of turbine manufacturers than the UK market. Over the period 2000-3, just five manufacturers supplied all turbines installed in the UK (compiled from various sources). In 2003, new installation of turbines in Germany was split between nine companies (IEA, 2004). This suggests that whereas the German market is of sufficient size and maturity to support competition, the market in the UK has not developed to the same extent. Moreover, the data presented in Figure 10 suggests that the level of competition has fallen through time, a change that may reflect consolidation within the industry or withdrawal from the market.³⁴

³⁴ Again, this is reflected in industry level data, which shows a couple of manufacturers gaining an increasing market share (compiled from various sources).

We also note that German turbine manufacturers account for a significant percentage of both the domestic and the international market. Two of the companies operating in the UK and five of the companies operating in Germany were of German origin. Moreover, the international market is dominated by manufacturers from countries that implemented feed in tariffs, namely Germany, Denmark and Spain.³⁵ Lauber (2004) suggests that the tariffs facilitated the development of the turbine industry by conferring security and encouraging market participants to adopt a long-term perspective. By contrast, the emphasis that the NFFO and the ROC place on reductions in the price paid for wind energy is unlikely to facilitate the growth of domestic industry. Instead, developers are likely to rely on technological advancements in other countries (Lauber, 2004; Menanteau et al, 2003).

Finally, we note that quota systems do not encourage the development of less mature technologies. In Texas, there has been a substantial increase in wind capacity, but solar generation remains too expensive to compete with conventional generation (Langniss and Wiser, 2003). In the UK, activity under the ROC scheme has been largely restricted to onshore wind and landfill gas (Mitchell et al, 2003). In turn, this means that market development and movement down the learning curve will be limited.

The results obtained for finance provision suggest that the level of competition is not significantly different under the NFFO and the Feed in Tariff. There appears to be greater competition under the ROC, which may be the result of general development in the market for wind energy. Alternatively, the market-based nature of the ROC may have encouraged entry of financial service firms, although this would contradict comments made by a number of developers suggesting that the banks were concerned about the level of uncertainty under the ROC. A larger sample, and greater experience of the ROC, is necessary to draw conclusions that are more robust.

The results indicate only limited competition in the market for the provision of financing – a result confirmed by indications that for example in Germany only few commercial banks provide financing for major projects. We do not know whether this is the result of lack of demand or supply. On the demand side, we note that in Germany, financial support was given by the cheap credit provided by the DtA (see above). Figures from the DtA suggest that initially between 80

³⁵ Together these countries supplied 90% of turbines in 2002 (Sawin, 2004).

and 90% of wind energy projects in Germany were financed with these low cost loans (Hemmelskamp, 1998). This may have delayed demand for commercial credit. Furthermore in Germany some of the capital – one quoted number was 25% - is provided through equity, whereas in the UK most of the ROCs wind projects are said to be financed on the balance sheet of utilities.

Competition between developers and between firms providing related services has not been significant in the UK. Survey data suggests that long and unpredictable time lags between NFFO auctions inhibited the development of a competitive market. This stop-go cycle is also likely to have impeded both innovation and domestic industry, and limited the extent of cost reductions (Sawin, 2004). We therefore suggest that the NFFO provided little opportunity for the realisation of dynamic efficiency. Mitchell et al (2004) suggest that the ROC may have similar drawbacks since the emphasis on achieving reductions in the price paid for energy precludes both many renewable technologies, and entry by smaller producers.

4.3 Conclusion: Competition under German and UK Policies

The initial question confirmed that the NFFO generated a higher degree of price competition among project developers than either the Feed in Tariff or the ROC scheme. However, the final price of wind projects is not only determined by the margins of wind project developers. Most of the value is created in turbine production and construction – competition in these sectors is stronger in Germany than in the UK and margins are likely to be correspondingly smaller. This competition is likely to have a greater impact on the final delivery price than the price competition in the NFFO scheme.

We suggest that the Feed in Tariff should be depicted as a RPI-X regulation scheme. The Feed in Tariff for new projects is adjusted every year, providing sufficient information for project developers to indicate their expected profit margins. The Tariff is then fixed for the lifetime of a project, providing long-term security similar to that given by the NFFO contracts. This security will facilitate financing and reduce capital costs associated with development. When determining the annual price reduction, the authorities have to identify the level of the tariff that ensures targets are achieved with due consideration for efficiency and effectiveness (see also Skytte et al, 2003). This only requires that

the profitability of project developers be evaluated, since it can be anticipated that project developers will try to obtain the best possible conditions for the services they have to contract.

In the process of tariff setting, the authorities should be aware of the low level of competition between turbine operators. As turbine developers frequently retain the operation of the wind farms, a favourable operation contract might provide for a channel to create additional profits from a wind project. Anecdotal evidence suggests that project developer sometimes obtain turbines below list prices and charge the list price to the investment fund: such profits should be attributed to the overall profit margin. Furthermore, when setting the Feed in Tariff, the authorities should furthermore assess the contracts signed with landowners. The strong competition among German project developers for new sites indicates that a large share of the margin between project costs and Feed in Tariff can end up with the landowners. This is only desirable to obtain the individual, community or regional support for additional deployment of wind turbines. If not required for these reasons high payments to landowners should be interpreted as a sign of excessive tariffs.

The variable wind resources between different locations implies that with a homogeneous renewable premium (ROCs or Feed in Tariff before 2000) or with a fixed cut of value for the acceptance of wind projects (NFFO), the site with lowest wind speed sets the premium or cut of value. The lower wind speed sites are only developed under these schemes if no higher wind speed sites are left. Hence, the high wind speed sites capture scarcity rents. If competition among project developers is high, then this scarcity rent will be passed on to land owners in the lease contracts. If competition is lower, e.g. because financing risk limits the number of developers to utilities with solid balance sheets, then the scarcity rent of high wind sites can be captured by the developer. The Feed in Tariff of the EEG since 2000 successfully addresses this difficulty by increasing the tariff per delivered MWh with decreasing annually production. It is a political decision down to what annual production level the tariff increase should be continued – currently 65% of the reference site.³⁶

³⁶ If the tariff were directly coupled to annual production, then no incentives would be provided for availability. Hence, the average production of a turbine over five years relative to the hypothetical production of the same turbine type at the German reference location is used to determine payment.

5 Conclusion

The NFFO and ROC schemes were expected to encourage the deployment of renewable energy at the lowest possible cost. We observe that deployment under the NFFO was well below expected levels, and well below that achieved in Germany. Further, the difference in the price paid for wind energy in the UK and in Germany is much smaller than is generally suggested, once the wind resource is taken into account. Based on the initial experience with the ROC scheme, and making rather conservative assumptions about future trends, we suggest that the resource-adjusted cost to society of the feed in tariff is currently lower than the cost of the ROC, when averaged over the lifetime of the project. The long-term price guarantee provided by the feed in tariff reduces regulatory and market risk and might explain the lower cost. This confirms Sawin's observation that a quota-based system such as the ROC is not inherently cheaper than a feed in tariff, but that cost depends on a number of factors.

A frequent criticism of the Feed in Tariff is that it does not generate sufficient competition. However, our analysis revealed stronger competition among turbine producers and constructors under the feed in tariff than under either of the UK schemes. As these are the stages of the value chain, which contribute most to the total cost, increased competition at this stages might have a stronger impact on final price. We suggest that the Feed in Tariff should be depicted as a RPI-X regulation instrument, which seems to work well if project developers have a well-defined task and interact in competitive markets such that their profit evolution can be easily observed in order to set future Feed in Tariffs. If sites with differing levels of wind penetration are to be developed, then a resource-based differentiation of the tariff prevents owners of high wind sites from capturing large scarcity rents. We noted a very low level of competition at the operational stage for all three funding schemes.

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