

Risk, Innovation and Market Rules: A Comparison of the Renewable Obligation in England and Wales and the Feed-In System in Germany.

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Abstract

The European Union is particularly rich in variations of different delivery mechanisms for increasing the use of renewable energy. The requirements of liberalisation in Continental Europe and the re-regulation of the UK's gas and electricity sectors in 2000, has established a new generation of mechanisms to follow on from early prototypes. This paper analyses two new mechanisms in detail: the England and Wales RO (The Renewables Obligation) and the German EEG (Erneuerbare Energien Gesetz). Both mechanisms have developed out of specific political considerations; both exist within very different institutions; and both have very different benefits. The EEG has been successful in deployment; in reducing risk; in developing an advocacy coalition; and in developing a new industry. The RO does not reduce risk (whether price, volume and market) which makes it difficult to obtain financing, so limiting new entrants and the development of an advocacy group. The large generators, so far, are able to carry the risks and do very well out of the RO. While this is the case, the UK Government is unlikely to be concerned by the lack of new entrants; the lack of a UK renewables industry and the lack of an advocacy coalition.

1. Introduction

The European Union is particularly rich in variations of different delivery mechanisms for increasing the use of renewable energy. The 1990's were dominated by two types of mechanisms: competition or quota based – for example, the Non-Fossil Fuel Obligation (NFFO) in the UK (Mitchell 2000) and variations on pre-determined premium payments or prices, as in Germany. However, the requirements of liberalisation in Continental Europe and the re-regulation of the UK's gas and electricity sectors in 2000, has established a new generation of mechanisms to follow on from these early prototypes. These mechanisms, while still fundamentally different from each other, represent a more sophisticated vintage of their earlier versions (Menanteau, P et al, 2003). This paper analyses two new mechanisms in detail: the England and Wales RO (The Renewables Obligation) and the German EEG (Erneuerbare Energien Gesetz). Both mechanisms have developed out of specific political considerations; both exist within very different institutions; and both have very different benefits. The Renewables Directive aspires to a European future with a similar renewable energy delivery mechanism, generally accepted to be more like the RO than the EEG. The analysis of this paper raises questions for, and highlights the difficulty of achieving, this vision, given the very different institutional and cultural arrangements in place.

2. The Delivery Mechanisms – how they work

2.1 Feed-in System - The German EEG

Germany has seen an impressive growth of electricity generation from renewables during the 1990's. This success is to a large extent due to a feed-in mechanism laid down in the first German feed-in system was introduced in 1991 (Stromeinspeisegesetz). This was a feed-in system based on the “market price” topped-up by a premium payment. Utilities were required to buy power from renewable generators and pay this premium for it, which was calculated as a percentage of the average price of electricity to end-customers. In such a system, the feed-in tariff would vary according to the general electricity tariff, exposing the generator to the development of these tariffs. As long as there was a monopolistic market, this was not a problem because prices were both high and relatively stable. As electricity prices went down after the market had been liberalised in 1998, prices paid to renewable generators fell and many came under pressure. The introduction of the fixed rates in the EEG that came into force in 2000 was largely a response to this.

The diagram below (Fig. 1) shows the growth of renewables stimulated by the first mechanism from 1991 until 1998 and the even stronger increase after the introduction of the new EEG mechanism in 1998. The EEG does not stipulate any upper capacity limit and the growth of renewable generation is likely to continue.

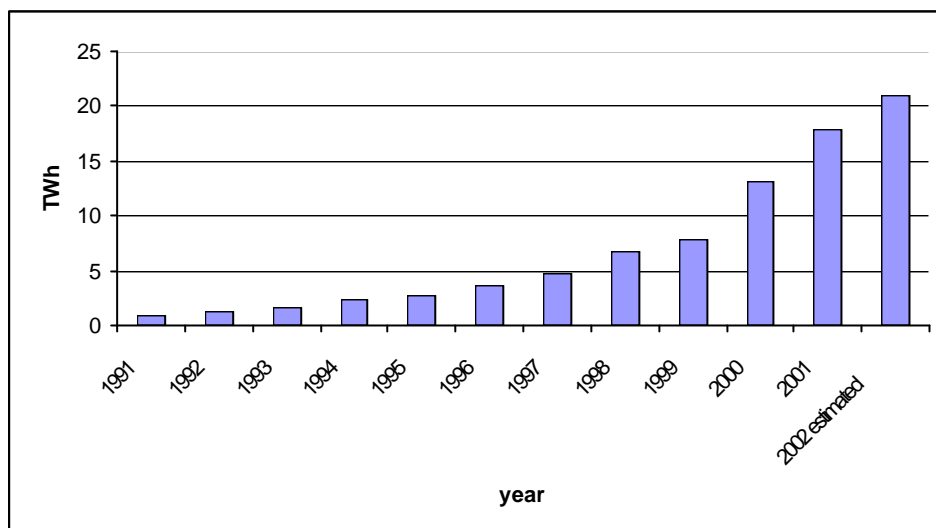


Fig. 1. Annual electricity generation benefiting from the feed-in mechanism (BMWi 2002)

The EEG requires network operators to;

- connect renewables to their grid;
- accept the entire electrical output from these plants;
- remunerate generators at a pre-determined rate for every kWh produced.

Plants that do not feed into the public grid are also remunerated. The remuneration decreases over time, but generators are guaranteed to receive remuneration for 20 years.

As shown in Table 1, the EEG supports a wide range of renewable technologies and places a lot of emphasis on differentiated remuneration:

- First, the remuneration depends on the technology, with only 7ct¹/kWh being paid for large geothermal plants and up to 51.62ct/kWh for solar plants.
- Second, the commissioning date is also relevant. For wind plants, for example, the remuneration decreases by 1.5% every year for new plants.
- Third, the remuneration is site specific. Wind plants currently receive 9.1ct/kWh for 5 years after commissioning (plants coming on-line next year will receive 1.5% less, see above) After that period, the remuneration depends on the income of a plant compared to a reference plants². Plants that have done well for example due to relatively good wind conditions and have received a remuneration that exceeds 150% of the reference plant income will receive less money after year five. Lower-quality sites, on the other hand, will continue to receive the full remuneration for longer, depending on the extent to which they are below the 150% threshold.
- Moreover, there is a review carried out by the government every other year, looking at technological and market developments. The review is required to make a recommendation to the parliament which can then decide to change both the tariffs and the reduction rates. They will only be changed ex-ante, i.e. only for plants that have not been commissioned yet.

¹ Throughout the paper, ct is used to represent euro cents.

² The reference plant is defined in the appendix of the EEG.

Table 1

EEG remuneration by technology (EEG)

Erzeugungstechnologie	remuneration ct/kWh
Wind	9.1
Solar • capacity<100kW • plants on a building, capacity< 5 MW	51.62 48.1
Biomass • capacity <500 kW _e • capacity between 500 kW _e and 5 MW _e • capacity between 5 MW _e and 20 MW _e	10 9.0 8.5
Hydro, landfill and sewage gas • capacity <500 kW _e • capacity between 500 kW _e and 5 MWe	7.67 6.5
Geothermal plants • capacity<20 MW _e • capacity>20MWeMW _e	8.5 7.0

Table 2 shows the share of total generation that has been supported under the EEG and the average remuneration.

Table 2

Average remuneration for plants covered by the EEG law (VDN)

Year	Share of renewables supported under the EEG of total generation	Average remuneration
2002 – Q3	5.14%	8.82 ct/kWh
2002 – Q2	4.28 %	8.74 ct/kWh
2002 – Q1	4.69 %	8.79 ct/kWh
2001	3.89 %	8.64 ct/kWh
2000	2.90 %	8.54 ct/kWh

The costs of the feed-in mechanism are paid for by all end customers. While under the old Stromeinspeisegesetz, each DNO had to bear the total costs of renewables in their area individually, the EEG has established a mechanism whereby the costs are spread country-wide. The DNO has the obligation to buy the output from renewables, but has the right to sell it on to the TNO it is connected to. The TNOs spread it equally amongst each other, depending on the share of electricity sold in their grid area. They then pass it on to the suppliers in their region. The costs of developing renewable energy in Germany is now socialised across all electricity customers rather than impacting more heavily on customers in area with more renewable energy.

According to the German government (BMW_i 2002), the feed-in mechanism has increased the cost of electricity to end users by 0.18-0.26ct/kWh, depending on the market price for electricity.

2.2 *The England and Wales Renewables Obligation – How it Works*

The Renewables Obligation (RO) came into effect in April 2002 (DTI, 2002), following on from the Non-Fossil Fuel Obligation (the NFFO) which was in place from 1990-1998. The RO was chosen to follow on from the NFFO because it was thought that it:

- was a market-based mechanism that would increase deployment whilst at the same time maintain a competitive incentive to keep prices down;
- would enable renewable generators to become more integrated into the electricity market;
- was non-technology specific so would not be attempting to pick winners.

The RO is a legislated obligation on licensed electricity suppliers to buy a certain percentage of their supply from 3% in 2002-3, rising to 10.4% for the period 2010-2011. The RO is intended to stay at the 10.4% level until 2027 – in theory, guaranteeing it for 25 years. The RO Order is the legal basis of the RO and obligatory reading for anyone interested in it (DTI, 2002). The Order sets out the list of eligible technologies for public subsidy within the mechanism. The RO generators must be situated within the UK or its territorial waters, and must have been built, or have been refurbished, since 1990.

Compliance of suppliers with the obligation is monitored by the UK Gas and Electricity Markets Regulator, Ofgem, which facilitates the system through:

- operation of a certificate system for eligible projects;
- monitoring generation output and the creation of renewable obligation certificates (ROCs, 1 ROC = 1 MWh);
- monitoring supplier compliance (suppliers have to provide Ofgem with proof of an appropriate number of ROCs);
- monitoring the links between ROCs and Levy Exemption Certificates (LECs) available to companies who have agreed to reduce their climate change levy by undertaking various energy efficient measures (including buying renewables).

Suppliers have to buy a certain number of ROCs each year to meet their supply obligation. The ROCs could be bought directly from an eligible renewable energy generator or from another supplier. This means that the ROCs are a tradable commodity, and as such up to 25% of a supplier's obligation can be banked for up to 1 year. The potential for the use of borrowing ROCs against generation in future years was discussed as an option of the RO, but was rejected due to the potential for manipulation of the ROC market.

The RO allows suppliers to choose whether or not to meet their obligation. They can 'buy-out' at the rate of £30 for every MWh of their obligation that they do not meet through the presentation of ROCs to Ofgem, and this cost can be passed on to customers. The presence of the buy-out price means that from the perspective of the

supplier, it is in their economic interest to buy renewables up to £30/MWh above the premium of conventional power. If the price of electricity available from renewables is above this figure, then it is in the economic interest of suppliers to buy the conventional power from the electricity market and to pay the buy-out price.

This basic calculation by suppliers is complicated by the ‘recycled green premium’. This is the re-distribution to suppliers of monies collected by Ofgem from the payment of the buy-out price. The monies are re-cycled to suppliers on the basis of the volume of ROCs they presented to Ofgem as a fraction of all the ROCs presented to Ofgem in the specified period. For example, if a supplier presents 5% of all the ROCs presented in a one year period, then that supplier would receive 5% of the buy-out fund for that period.

The recycling of the buy-out introduces an element of ‘gaming’ into the RO. Suppliers have to understand in detail the provision of total renewable electricity supply for any one year. They can then estimate the short-fall on meeting the RO and therefore the total ‘buy-out’ and hence their green premium income. In effect, the green premium to a supplier raises the price per kWh at which a supplier remains economically indifferent to buying renewables rather than paying the buy-out price.

In addition, the buy-out price is the cap on expenditure of the RO each year. It ensures that customers do not pay more than an additional 3p/kWh for a maximum of 10% of electricity. This is a vital part of England and Wales strategy. Without a price cap (and hence cost to customer), it is unlikely that the Department of Trade and Industry could have got agreement for the RO from the Treasury.

A RO generator has, de facto, four revenue streams:

- Payment for energy;
- Payment for the ROC;
- Payment for the LEC if final customer is eligible for levy exemption³;
- The recycled buy-out payment or green premium.

Table 3
Constituents of Total Value of Renewable Generation Eligible for RO in early 2003

	p/kWh
Energy	1.5-1.8
ROC	3.0
LEC	0.086
Recycled Green Premium	1.5-2.0
Total	6.1-6.9

³ Under the climate change levy (CCL) agreements, certain major energy users are able to reduce the normal CCL payment (0.43p/kWh on all business customers) to a fifth (ie 0.086p/kWh) if they purchase renewable electricity from eligible power plants or undertake certain energy efficiency measures (agreed with the Energy Savings Trust). This provides a value for Levy Exemption Certificates (LEC = 1 MWh). The major users provide proof of LECs to Ofgem and Customs and Excise.

The RO is therefore agreeably simple but has a number of distinct advantages for a market-orientated Government:

- it acts as an accounting system to verify whether the obligation has been met;
- all suppliers are legally bound to fulfil the obligation on them, although they are able to choose how they fulfil it or whether they wish to 'buy-out' at 3p/kWh rather than buy eligible electricity;
- the suppliers have to pay whatever it takes up to 3p/kWh to meet their obligation. The RO is therefore a way to generate finance to pay for renewables external to Government;
- they facilitate trade which allows the obligation to be filled either by buying physical electricity with ROCs or by ROCs alone in the alternative tradable ROC market (Santokie, F, 2002);
- suppliers are able to pass costs on to customers, but there is a cost cap to customers of the RO.

3. Risk Reduction, Efficiency – Short and Long Run and Incentives for DNOs and Balancing

The EEG and the RO are analysed in the sections below.

- Firstly, to see if they are effective and efficient in promoting deployment, particularly through reducing risk.
- Secondly, to see if they stimulate of innovation
- Thirdly, to examine the extent to which they fit into market rules.

3.1 The German EEG

The three main areas presented here are as follows:

- Feed-in systems are effective in increasing the share of renewables because they reduce three different kinds of risk for RES generators, thereby improving access to capital and reducing the cost of capital;
- Feed-in systems are not the most efficient approach in the short-term, yet they do provide incentives and resources for innovation leading to efficiency improvements in the long-term. Decreasing feed-in tariffs can be used to pass on some of the cost-savings resulting from these improvements to those who pay for the feed-in mechanism;
- Feed-in systems have to be seen in the wider regulatory context incentivising DNOs. The distribution of costs incurred by such a system plays a key role in that it gives DNOs neither positive nor negative incentives to connect RES plants to their network.

3.1.1 Risk Reduction

Both the effectiveness and the efficiency of a feed-in system are to a large degree dependent on the guaranteed feed-in tariff. If this tariff is too low, it will not lead to a significant increase in renewable generation. If it is too high it provides renewable generators with additional income, whilst triggering investment at increasingly disproportionate cost and eventually no additional investment at all. In the case of

feed-in systems, however, finding the 'right' price is relatively easy compared, for example, to a tax on CO₂ emissions, because the costs of avoiding CO₂ are less well known than the generation costs of renewables.

A feed-in system is one mechanism for ensuring a renewable generator receives a price that is above the market price, reflecting the fact that these technologies are, as yet, not competitive. However, it is the manner in which this premium price addresses the problems facing renewable energy projects that distinguishes the feed-in system from other mechanisms where plants also receive a price above market levels, e.g. through selling green certificates as in the Renewables Obligation (RO), discussed below. The success of feed-in-systems in increasing the share of renewables can be explained in terms of the lower risk/ higher security it gives to investors compared to other support mechanisms (Oppermann, 2002; Menanteau et al, 2001, see also Langniss, 1999). This security can be split into three elements:

- Price risk
- Volume risk
- Balancing risk

3.1.1.1 Price Risk

A fixed feed-in price, as with the German EEG, does not have any price risk for the renewable generator since the price paid does not depend on the market price.

In a liberalised market, this price guarantee is arguably more valuable than in a monopolistic market. In the former market, prices are normally much more volatile and market players pay high premiums for converting fluctuating market prices into fixed income streams. Hedging can be done through a contract that limits the price fluctuation to a certain price band or a fixed-price contract. The corresponding hedging fee reduces the risk, but at the same time represents an additional cost. As many renewable generators are small generators, they tend to be relatively risk averse due to a less diverse fuel portfolio and a limited ability to finance projects through the balance sheet. They are therefore likely to be disadvantaged by high-risk markets (Oppermann, 2001). They are therefore likely to pay relatively high hedging fees for reducing their risk to a minimum.

Thus, the guaranteed feed-in tariff gives generators not just a price that lies above the market price. It also provides a hedge against price volatility, thereby saving them money they would otherwise have to spend on hedging their price risk. The higher the price volatility, the higher the value of a guaranteed feed-in tariff.

3.1.1.2 Volume Risk

A generator's revenue is a function of both price and volume. In a feed-in system, there is no volume risk because the network operator is obliged to accept all renewably generated electricity. A quota system sets an overall volume for renewable generation, it does not give individual generators a guarantee that their output will be bought. Under such a system, a plant that can sell all its output in the beginning may later be replaced by cheaper generation. Volume risk is related to the amount of money the Government is prepared to have spent on renewables, by whoever pays for

it, as discussed later. If the mechanism is essentially revenue capped as both competitive mechanisms and quota mechanisms are, then there will always be volume risks.

3.1.1.3 Market Balancing Risks

A feed-in system side-steps the risk of balancing. This important point is generally not discussed by other analyses of how the feed-in system reduces the generators risk (e.g. Oppermann 2001). For example, in Germany, EEG plants do not need to supply a certain load profile. They simply feed their output into the grid and the Distribution Network Operator (DNO⁴) has to deal with giving it the right shape (Bauknecht, 2003). The DNO has to remunerate the electricity at a fixed rate irrespective of the load profile. For many renewable power plants which generate intermittent power, this reduces their risk significantly as shown by the experience of renewables under the New Electricity Trading Arrangements (NETA) in the UK (Bathurst and Strbac 2001; Bauknecht and Collela, 2002). As discussed later, NETA places a high premium on flexibility and penalises unreliable generation. A feed-in system that is based on the number of kWh and does not take into account the load profile does not penalise unreliable generation.

On the other hand, such a system does not give generators any incentive to reduce their load fluctuation or benefit renewables which provide reliable power. There is scope for biomass plants to react to market conditions and even for wind generators to run slightly below their maximum to provide a certain reserve capacity. Further exploration is needed to determine how a feed-in system can be more effectively combined with incentives for generators to provide some balancing capacity.

3.1.1.4 Conclusion

The current German feed-in system for renewables has a number of advantages for renewable generators in terms of reducing their risk. The effect of this reduced risk is an increased ability for renewable generators to finance their investment through the capital market. This way of financing is particularly important for the large number of small companies active in the renewable market, as they normally cannot finance their projects through their balance sheet. The low risk improves their access to capital markets and reduces the cost of capital. This effectively means a reduction in the overall costs of renewable generation, which should be reflected in the level of feed-in tariffs. As Langniss (1999: pp112) has pointed out, “in policy development, mitigating risk is certainly an alternative to raising the level of compensation”.

3.1.2 Efficiency: Short and long-run

The efficiency of a support mechanism depends on the amount of financial support that is necessary to achieve a certain share of renewables, both in terms of bringing renewables to the market now (static efficiency) and making them more competitive in the long-run (dynamic efficiency). While static efficiency only looks at the immediate cost of bringing a certain capacity on-line, dynamic efficiency also takes into account longer-term cost-reductions through innovation.

⁴ A DNO in this context is a company which is both the distributor and the supplier to customers.

From a short-term perspective, a support mechanism may have a low efficiency whilst in the long-run, it may lead to innovative, more efficient technologies that will reduce the cost of electricity from renewables. The success of a support mechanism should therefore not just be evaluated in terms of how much capacity it brings online in the short-term. Another important criterion is how it fosters the development of renewable technologies and thus contributes long-term reductions in the cost of technologies.

For feed-in systems to be effective, the remuneration has to cover the total costs of a plant. In terms of short-run efficiency, a major problem associated with feed-in systems is that all plants get the same feed-in price irrespective of their costs, although the cost differences between different technologies and sites tend to be significant, leading to a steep supply curve. As a consequence there is a high generator surplus and plants with low generation costs can make a profit that is not justified by the objective to support renewables. To ameliorate this problem, feed-in tariffs can be differentiated by technology (e.g. lower prices for wind, higher prices for solar) and site (e.g. depending on the amount of wind). As described above, the German EEG establishes technology specific remuneration. This is certainly beneficial for high cost technologies like solar that would otherwise have no chance of receiving around 50 ct/kWh.

In terms of long-run efficiency, a feed-in system differs from other systems in the way it gives incentives to innovate. A generator has no incentives to become more efficient in order to remain competitive, because the feed-in system removes their volume risk. However, reducing costs will increase the generator's profitability. Thus, the mechanism does provide some incentive to innovate (Menanteau et al. 2001). If the feed-in price does not decrease over time, generators can keep the entire surplus resulting from the efficiency increase, giving them both the incentive and resources to innovate.

At the same time, with a fixed feed-in tariff, generators do not have to pass on any cost savings to those who pay for the feed-in system and the short-term efficiency will decrease as generators get a remuneration that is above the level necessary to make plants profitable and the ratio of overall feed-in payments and kWh generated does not change. This can also be the case for quota systems (see below). Innovation does not only show itself through an increasing producer surplus, but can also reflect the opening up of new renewable energy resources, such as low-quality wind generation sites that have not been profitable before an innovation occurred.

In order to transfer some of the efficiency gains to those who pay for the mechanism, it is, however, necessary, to introduce decreasing feed-in tariffs for new plants, increasing the short-term efficiency. This reduces the incentive for generators to innovate resulting from the prospect of higher surpluses, but at the same time gives them an incentive to innovate in order to remain profitable even with new plants that receive a lower payment. When introducing decreasing tariffs policy-makers are faced with the dilemma that on the one hand the decrease should be announced well in advance to give generators the security that makes feed-in mechanisms successful (see above). On the other hand, they cannot know in advance which cost savings will result from innovation. Nevertheless, this is the second major distinction between past

and new feed-in tariffs. It attempts to provide security, while also trying to incentivise price reduction.

3.1.3 Incentivising DNOs and Markets

It has been repeatedly argued that simply comparing different models of supporting renewables is not sufficient and that it is important to look at the concrete implementation of a given system (Huber et al. 2002: 151; Timpe et al. 2001: 63-102, Bechberger et al.). This should also include the wider regulatory framework that the delivery mechanism is embedded in. The DNOs play a prominent role when it comes to supporting or undermining renewables and aspects of incentivising DNOs are analysed below.

Supporting renewables through a feed-in system leads to higher costs of electricity generation. When designing such a system, one question to be answered is how to distribute these additional costs. There are a number of alternatives:

- The costs of a feed-in system could be carried by the DNO (in German sense) that the respective plant is connected to and who has to take off the generated output and remunerate the generator
- It could be spread over all DNOs
- It could be distributed among all electricity customers
- It could be paid by the taxpayer.

There are a number of arguments for distributing the costs among all customers. Renewable generation generally, and particularly wind, are unevenly distributed throughout Germany. Penalising DNOs or customers in an area with high wind penetration would appear to impose an unfair burden on customers when the environmental benefits are distributed over Germany as a whole. Spreading the costs across all customers and DNOs (in other words averaging the extra cost across all customers) leads to a mean increase of the costs of electricity from all energy sources, thereby internalising some of the external effects of other conventional technologies (Oppermann 2001: 6).

As Enzensberger et al (2002) have rightly argued, the evaluation of support mechanisms should take into account the different interests of all relevant stakeholder groups. This is not just a fairness issue, but also significantly influences the success of the support mechanism. The distribution of costs is an important aspect and heavily influences the support for a feed-in system.

The German DNOs that the power plants are connected to are central stakeholders. They play an important role in making a feed-in system successful and it is therefore important to give them the right incentives. Although DNOs are required to accept the entire electrical output from renewable plants, they may have incentives to avoid this obligation, particularly where they have to bear a high proportion of the feed-in costs. An evaluation of a feed-in system therefore needs to include the wider regulatory framework, in order to;

- see which incentives and disincentives there are for DNOs to connect RES plants;

- find the loopholes that make it possible for DNOs to undermine the feed-in mechanism.

While DNOs may be disincentivised from integrating new renewable energy generation capacity to their grids, to act on their opposition they must have means to prevent it. The German example highlights a number of ways in which DNOs can weaken a support mechanism, even if they are obliged to connect plants and buy their output at a fixed rate. These include:

1. They can try and prevent plants from connecting or at least delay the process.
2. They can refuse to provide the necessary information or charge high fees for it.
3. They can offer unfavourable metering conditions.

3.1.3.1 Connection Costs

A major difference between the EEG and its predecessor is the introduction of increased socialisation of costs. The DNO can pass on the energy including the costs of remuneration paid to EEG plants to the Transmission Network Operator (TNO) they are connected to (ie the company operating the high voltage transmission grid). The TNO in turn can pass it on to the supply companies, which will distribute it among all end users. This burden sharing mechanism introduced by the new EEG has removed one of the main disincentives for DNOs to support an increase in renewable generation on their grid.

However, although the requirement to remunerate the power plants no longer affects the DNO, there remain a number of reasons for them to be opposed to an increase of renewable generation in their area. Renewables also induce further costs for DNOs, in addition to those associated with the fixed tariff. These include;

- Connection costs: If there is a system of shallow connection charges, as in Germany, it is the DNO which has to provide the network upgrade and extension necessary to get the plant connected;
- Balancing costs: If the DNO is responsible for providing the balancing capacity and energy for renewable plants, the intermittent generation from RES plants increases the balancing costs of DNOs. Unlike the feed-in costs, the German DNOs cannot currently pass on these costs to the TNO. Increased socialisation of balancing costs would reduce the disincentives for DNOs to connect DG plants to their grid;
- There is also the issue of transaction costs. The renewable operator represents an additional counterpart which the DNO has to deal with (signing contracts, transferring money etc.) without any potential to make money out of this relationship. Additionally, the DNO also has to deal with the TSO which then has to refund to the DNO the payment the DNO has previously made to the RES operator. This requires additional staff and thus increases the costs for the DNO.

As a consequence, some DNOs have tried to prevent renewable power plants from connecting to their grid, thereby undermining the effectiveness of the feed-in

mechanism, however well-designed. It is clear that a renewable energy policy would be more successful if it was set up to incentivise DNOs to want renewables.

3.2 The England and Wales Renewables Obligation

As shown below, the RO does not remove risks. Only large, integrated energy companies appear able to overcome the price, volume and market risks and for those companies, the RO is a welcome and valuable mechanism. Other smaller or independent companies do not find it sufficiently 'powerful, persistent or predictable' (Jacobsson and Bergek, 2002) to either enable, or induce, their involvement. Whether the large companies will be sufficient to deliver the successful deployment of 10% of renewables by 2010 is too early to say.

3.2.1 Price Risk

There is a great deal of price risk within the RO. The value of the ROC and green premium depends on supply and demand (Smith, A and Watson, W J 2002). The DTI has set out the level of obligation in each of the years to 2010 (DTI, 2001). An exact knowledge of the state of deployment and generation output for every eligible renewable power plant is necessary to understand the value of the ROC and green premium for each year, based on the expected percentage of buy-outs (Santokie, F, 2003). The Renewable Power Association (RPA) predicts a shortfall between supply and demand of 55% in 2003-4 and 20-30% in 2006-7. They predict this will continue until the target is met, more likely in 2012/2013 (RPA, 2002). As a result, the value of ROCs with recycled premium will stay at around £45/MWh until about 2007. Once the 10.4% target has been met, the value of the ROC will fall. This is because renewable generation beyond 10.4% is not guaranteed a ROC. As supply increases, suppliers will be able to choose between generation and this also reduces the value of the ROC.

The value of the ROC therefore:

- Depends on the rules of eligibility of the RO remaining unchanged. If eligibility altered, it would have an effect on the supply curve. If eligibility increased, which seems more likely than it reducing, in order to meet the Government's target figure, it would increase available supply, and the value of ROCs would reduce.
- Will alter once the 10.4% target has been met, since supply of renewables will increase thereby reducing the value of the ROCs, though this will not necessarily be in 2010-11 and only in the continued absence of a higher target (Oxera, 2001)

The highest prices paid for the RO is the ex-NFFO generation, now auctioned off every six months by the Non Fossil Purchasing Agency. This is for a 6 month contract and for existing generation. Prices paid for the RO become lower than this depending on length and type of contract and type of generation.

Table 4
 NFPA Auction Prices/kWh

Technology	Feb-01	Sep-01	Feb-02	Aug-02	Feb-03
Price	p/kWh	p/kWh	p/kWh	p/kWh	p/kWh
Small hydro	1.84	2.81	6.4	6.69	6.45
Landfill	1.92	2.84	6.74	6.76	6.56
MIW	1.59	2.21	2.27	1.93	1.64
Biomass	1.85	2.61	6.52	5.88	3.68
Wind	1.85	2.84	6.31	6.65	6.41
Average	1.89	2.81	6.44	6.5	6.26

Prices are for electrical output, and for appropriate technologies, inclusive of Climate Change Levy Exemption Certificates (LECs) and Renewable Obligation Certificates (ROCs). (NFPA, 2003)

There is limited trading of ROCs because most of the larger generating companies sell to their in-house suppliers. For example, National Windpower and Powergen Renewables are likely, although not certainly, to sell their ROCs to Innogy and Powergen, their parent company's suppliers or trading arms.

The ROCs are not traded separately in the ROC market, which makes the latter market illiquid. ROCs for the first obligation (i.e. for the six months from April 2003) were recently bought at £46.75p/MWh. This value represents the ROC, the recycled green premium and potentially a LEC. The energy value (about 1.5-1.8p/kWh), obtained by selling it separately, should be added to this to obtain the total value to the generator. ROCs for the Second Obligation period (i.e. 2003-2004) are currently bid/offered £47-49/ROC and the Third Obligation Period (i.e. 2004-2005) is bid/offered £42-44/ROC (Natsource Tullett Europe, 2003). These contracts are therefore only for a year. A generator which wishes to have a longer term contract will be paid less. The maximum length contracts to independent generators are usually for five years, not enough to obtain project finance, while larger integrated companies may obtain longer contracts for around 10 years or so.

Since the ROC value (and the recycled value) falls if the obligation is met, the RO is a mechanism which inherently includes an incentive to under-meet the target. Since, in order to know what the value of the ROCs and recycled premium is, and given the very few generators around, it must arise that generators decide to commission to suit ROC values, although this is difficult to prove.

3.2.2 Volume Risk

The RO also has volume risk, as touched upon in the section above. Once the 10% target has been met, if there is not a higher target, suppliers are able to choose from different sources of supply. This means that renewable generators do not have security that their generation will be bought after that date. The Government reiterated within the White Paper that the RO would last until 2027, meaning that suppliers would be obliged to buy 10.4% of their supply until 2027. However, new generation

which comes on line will have a zero ROC value unless it is bought to fulfil the obligation. In this case, it would displace existing RO generation. Suppliers can be expected to source cheaper generation, if it is available, once the 10% target has been met. Thus, the ROC values, as supply becomes greater, reduce (OXERA, 2001).

The Government stated in the White Paper that the RO will exist until 2027. Nevertheless, there is political risk that the RO will end; that another mechanism will be introduced which sidelines it; and even that it might improve, for example with a rolling, increasing RO target. The renewable industry know that this occurred with the NFFO contracts which are still in existence but at a much lower value than obtainable through the RO. The White Paper also stated that carbon trading would be at the centre of its energy policy. This has given rise to concerns about how the RO will link with carbon trading in the future; whether the latter may undermine the former and what this means for ROC values.

3.2.3 Market Balancing Risk

Generation from the RO is also open to market balancing risk. The RO establishes a demand for renewable electricity by suppliers but it provides no other support. An explicit goal of the RO was to force renewable generators into taking electricity market decisions. This is a good long-term goal. The question is whether the positive effects of moving directly from the secure NFFO (15 year contract for a price/kWh and priority access by regional electricity companies) to the RO (where generators have to negotiate a contract with suppliers and work within the new electricity trading arrangements (NETA)) are outweighed by the problems for smaller and independent generators.

There are two key difficulties for smaller and independent generators:

- the fundamental idea of NETA was that it should be cost-reflective and promote reliability of power. NETA trading occurs between Balancing and Settlement Code (BSC) signatories and is a complex mechanism which imposes high transaction costs in terms of membership, personnel and information technology and together imposes a disproportionate, relative cost on small generators. Because of this most small generators do not sell through NETA but via a supplier. Many grid supply areas, the distribution network area that generators sell into, only have one supplier which means they have limited options for sale of their generation. If the renewable energy is sold outside of the grid supply point, it loses its distributed benefits.
- NETA has a unique dual price system with a system buy price (SBP) and a system sell price (SSP). The system operator balances the system and if renewable generation from a power plant is either over or below what it said it would generate in a half hour it has to pay a penalty to 'balance' its output. There is a cost differential between the SBP and the SSP. In effect, it costs more to buy if you are out of balance as a result of under-generating. It is possible to have price spikes, although it is much less likely now than it was when NETA came into operation in April 2001. At those times, the cost of balancing can be onerous. As a result of this, suppliers are concerned at the additional risk of buying intermittent generation.

Most renewable generation in the UK is owned by subsidiaries of the larger energy companies which also own suppliers. NETA does not pose very much of a problem for them because the renewable generation becomes part of their portfolio to balance. However, from the perspective of new entrants, NETA is a barrier (Ilex, 2002a, 2002b, 2002c; Tudway, 2003).

3.2.4 Conclusion

The RO embodies far more risk than the feed-in mechanism. From the perspective of financiers, payments which result from the RO are not secure for the several years they require. The majority of finance has therefore been provided from the balance sheet of the large generators, which are subsidiaries of the old monopoly companies. The 2010 target requires about 1250 MW of new build a year (DTI, 2003). This equates to at least a £ billion pounds a year and it seems unlikely that even the deepest of corporate pockets will want to provide all of this by corporate finance. If limited project finance is forthcoming, then the ability of the RO to deliver the 10% is questionable (RPA, 2003).

Independent generators may obtain finance but usually on the back of the assets of other power plants. Smaller generators communities or individuals, without assets, are unlikely to find finance. In this sense, the RO is a large company mechanism. It does not promote mentors for renewable electricity. Jacobsson and Bergek (2002) argue that the creation of an advocate coalition is a vital step in the development of a successful renewable energy industry. This is discussed further below.

3.3 Efficiency – Short and long run

As Section 3.1.2 illuminated, there are two types of efficiency – static (ie bringing renewables to market now) and dynamic (making renewables more competitive over the long term and other longer term benefits, such as the development of manufacturing industries).

The NFFO was clearly not efficient from a static point of view while the RO may be more efficient. There is certainly far more movement within the renewables industry in the UK since the RO. Planning permission applications have soared and consent was given to more wind power projects in 2002 than were installed during the previous 11 years combined. For example, 637.22 new megawatts of wind power received planning permission, compared with the combined installed total of 552.2MW to the end of that year. The BWEA reports interest from 70 sites for Round 2 of Offshore Bidding representing ‘thousands’ of MW to be decided in September 2003 (BWEA, 2003).

The RO is not efficient from a static point of view to the extent that it does not bring a wide range of technologies into the market. It was explicitly established in a way that would not favour any particular technology or ‘pick winners’. The basic idea of the RO, set out in Rader and Norgaard (1996) is that the supplier chooses to meet their obligation by buying the generation they wish. In general, this will be the cheapest generation but they may choose to buy more generation which is more expensive in the short-term if they expect it will become cheaper in the future. In this sense, technologies would be developed based on their predicted ability and importance in

the future. However, the introduction of the buy-out price within the RO removed the pure competitive drivers envisaged by Rader and Norgaard. In the UK, the generation bought so far has been landfill gas and onshore wind.

In order to broaden the diversity of the RO, capital grants valued around £350 million(m) to be spent between 2002/3-2005/6 are available for different technologies (DTI, 2002 and DTI, 2003). For example, of the £350m, offshore wind will receive £86m. Projects bid in to tendering rounds for a maximum percentage of their eligible project costs or a maximum amount. For example, bids for offshore wind can be up to 40% or £10m. The capital grant effectively brings the price/kWh from an offshore wind farm down under the RO price cap, over which it is not in the interests of suppliers to buy RO generation. This enables a wider set of technology support, although this is constrained by the total capital grants available. Nevertheless, it ameliorates a major problem inherent to the RO to a degree. However, whether it does so to the extent that the UK will be able to develop an industry is less clear.

Similarly, the RO has not widened new entrants as renewable generators. The RO has been good for generators able to:

- finance their RO projects in the same way as they did the NFFO projects, i.e. with corporate finance over 10-15 years or so;
- capture most of the renewables RO value, ie generators with integrated supply companies such as Powergen and Innogy;
- side-step balancing risks, again those with a portfolio of generation and a supply company able to maximise the distributed benefits.

Most renewable energy generators in the UK are able to bring these three factors together because they are, on the whole, subsidiaries of the ex Monopoly, CEGB. The RO is not providing equal support for independent generators. This is mainly because the risk under the RO is such that obtaining finance is difficult, as discussed in section above. However, it is also because suppliers prefer to buy from their in-house generator, if they have one. Suppliers can and do buy from generators which are not part of their company but they will incorporate a risk factor in the price they pay for the ROC or for the combined ROC/energy. The remuneration is therefore lower for independent companies which, in addition, have to accept shorter contracts and are less able to achieve economies of scale elsewhere.

The RO adds to the cost of electricity. The generators are now being paid 6-7p/kWh (about 9-10ct/kWh), which gives them a good profit. This is a much higher than the payments under the NFFO (see Table 2). The payment per kWh under the RO is now about the same as the EEG tariff which is guaranteed for 20 years, as opposed to the 25 years in the UK.

The annual cost to the UK customer will rise to the maximum amount in the year the target is met. The annual cost is the 3p/kWh buy-out price multiplied by the TWhs required each year, as set out in the Renewables Obligation Order. The White Paper states that the cost of the target will be around £1bn in 2010 (assuming it's met). In addition, there is now around £350 million pounds to be spent on renewables R&D and capital grants between 2002/3 and 2005/6 – in other words about £120m/yr. Once supply is greater than the obligation, then the lower costs will be passed on to

customers. There is also a cap to the total costs, both annually and for the length of time. This is an extremely important principle for the UK.

The dynamic efficiency over the long run is much less clear with the RO. If it continues to promote a limited mentoring group and if it continues to constrain capital grants then it is questionable it will be efficient.

3.3.1 Incentivising DNOs and Markets

There has been a great deal of work undertaken in Great Britain with respect to:

- how distributed generation should be connected to the grid;
- how distributed generation should pay for the use of the electricity system;
- what technical gaps there are in the understanding of how networks should be operated with large percentages of distributed generation;
- how any extra infrastructure costs, which occur as a result of the increased renewables, should be paid for;
- what additional costs this will impose on customers

This has occurred, firstly, because it became clear that the monopoly price controls (or regulation) on distribution network operators incentivised them to transport centralised power across their networks in a passive manner and that it was not in their economic interest to connect distributed generation. A joint DTI/DEFRA/Ofgem Working Group Report in 2001 (EGWG, 2001) formally confirmed these concerns. These price controls conflicted with the DNO License which states that Ofgem and DNOs must facilitate competition in generation and supply.

Secondly, Ofgem realised that more distributed generation would be connecting to the distribution networks and that this would have a profound effect on the way that the electricity system operated and was likely to increase costs to customers, if done badly. Ofgem and DTI have set up another working group – the Distributed Generation Working Group (DGWG) - and this has around 40 projects looking into different technical concerns of increased levels of distributed generation. In addition, the UK research councils have set up a £5million research programme called SUPERGEN to examine further technical concerns.

In addition to the work being undertaken by Ofgem through the DGWG, there have been some significant studies into the infrastructure and balancing costs of a number of different scenarios of increased levels of renewables and/or distributed generation (Milborrow, 2001; Ilex/UMIST, 2002; BWEA, 2003a; Dale, 2003). This has been undertaken so that technical requirements and costs are better understood in the hope that they can then be translated into regulatory incentives.

The SCAR report makes clear that the most expensive way forward from the network perspective is for targets to be met by mainly one technology in a limited region of the UK. The least cost way forward is to promote as many different types of technology as possible, in as broad a size differential as possible and spread them around the UK. From the perspective of the total cost of meeting increasing renewable energy targets, there is a balance to be made between the increased costs in the short term of a delivery mechanism, which promotes a wider set of technologies, against lower infrastructure and network costs over the longer term.

It is the intention of Ofgem to incorporate new incentives within the 2005 Price Control.

4. A Comparison of the RO and EEG

The RO and the EEG, or quota's and pre-determined prices, are very different but both have their own benefits. The key areas of difference are;

- Deployment, as a result of risk reduction;
 - Market hegemony versus creating conditions for deployment;
 - Existence of cost caps, even though payment to renewables similar;
 - Creation of new entrants and 'advocacy coalition';
 - Network development;
 - National industrial policies.
1. It is clear that in terms of deployment, the feed-in mechanism has been very successful, although at a cost to the German customer. It is too early to tell how successful the RO will be, although it is likely to be more successful than the NFFO. The payment in the RO and the EEG is now similar. Because the EEG ties the payment to a particular project, the risk is removed for that project. Because the RO ties the payment to an amount of generation, projects carry risks in terms of price, volume and market for all generators. Only large, integrated companies seem able so far to overcome that risk. Even with them, it is not clear whether the large generators will be able to obtain finance in the required amounts.
 2. The fundamental difference of principle between the UK and Germany is the former's view on the centrality and hegemony of the market. This compares to a more pragmatic, regulatory approach in Germany. The latter has been prepared to allow renewables to be exempted from some of the requirements of the electricity market (and networks). Such exemptions seem unlikely to occur in the UK, not least because the White Paper reaffirmed the importance of competitive markets. Moreover, it has never been a possibility that renewable energy would be supported in any other way than a competitive mechanism (Mitchell, 2000). That the competitive NFFO did not require renewables to become part of the electricity market was seen as a weakness by the DTI, to be rectified in the RO. The UK principle is that primary markets should not suffer intervention (for example, by exempting renewables from them) although measures, external to the market, can be implemented to remove them. It is because of this that the RO has price, volume and market risk, even though the RO itself pays more or less the same as the EEG, except for photovoltaics.
 3. The EEG has no upper limit to the capacity that can be added in one year, and hence no upper cost to customers. A political commitment to the costs of such a mechanism is necessary into the medium term. The result is steadily increasing annual costs as the volume of capacity eligible for subsidy increases. Sections of business in Germany have argued vociferously against this but has not altered the policy. The RO limits the costs to be passed on to

the consumer by limiting payment (through the buy-out) and capacity of the obligation. Such control is seen as vital by (at least) parts of Government such as the Treasury. This assures certain sections of business but it reflects the limited parameters beyond which the UK is not prepared to support sustainable development. This undermines confidence for new investors into the renewable industry while adding confidence to the larger companies able to benefit from the RO.

4. The EEG provides support in such a way that it is open to any new entrants, small or large, and open to different forms of financing. The RO limits new entrants, primarily because of the difference in risk which either reduces investor confidence or excludes certain generators from obtaining finance. While the RO induces investment from large companies, such as Innogy or Powergen, in the UK, there is likely to be limited concerns about the lack of new entrants. However, a recent Economic and Social Research Council workshop in the UK highlighted the potential importance of personal responsibility (of individuals, businesses, communities, schools or local authorities etc) or co-commitment to meeting the very large targets and aspirations set out in the White Paper. If this is the case, then having a delivery mechanism which draws in new entrants or mentors for renewable energy (in Jacobsson's language the creation of an advocacy coalition) may become more important in the longer term. In this case, it is hard to see how a competitive or market mechanism can provide that since by their nature they foster economies of scale.
5. What the UK has done well is to analyse questions of how the electricity network should develop for increased levels of renewables; how much it will cost; how it should be incentivised; and who should pay for it. This reflects the importance of the market to the UK and legal duties on Ofgem and system operators to promote competition in generation and supply. The thrust of this work is to remove economic regulation which unfairly undermines distributed generation and to create a 'level playing field'. Distributed generation includes renewables but also any other generation which connects into the distribution network. The legal Duties of Ofgem would not allow, for example, rules of connection or use of system charges to 'tilt' the playing field for renewables, as compared to other forms of distributed generation.
6. The high level of stability inherent in the feed-in mechanism, in comparison with the RO, may also have important implications for national industrial policies. It is accepted as part of the theory on innovation policy and industrial policy that a stable domestic market is essential in the development of a successful domestic manufacturing base. Whilst establishing a stable market does not imply the creation of a domestic manufacturing industry in a sector, it would appear that failing to do so generally guarantees failure to develop such an industry. It is perhaps not co-incidental that those countries with successful wind turbine manufacturing sectors, notably Denmark, Germany and Spain are characterised by their use of feed-in type mechanisms. Thus it may be that at the national level the increased costs of this kind of regulation have the potential to bring returns in terms of the social and economic benefits inherent in the creation of new industry.

So far the mechanisms established in the UK have not had the primary goal of benefiting, or developing, national industries.

7. The RO is a tradable mechanism and therefore more able to fit with a European or global renewable or climate change mechanism. The importance of this will become clearer as climate change policies unfold. In the short-term, however, this is a source of uncertainty for investors in the UK while of little practical importance to Germany.

5. Conclusion

The fundamental requirement of a national policy is to deploy renewables, arguably at least cost to customers, as shown in Figure 2 below. Germany and the UK have followed two very different paths. As Figure 2 shows, in theory, it is expected that the UK method would be cheaper. This is certainly the case so far since, despite twelve years of support, the UK has barely got off the ground in terms of deployment (an additional 1% or 1000 MW). Whether the UK will reach the nirvana of both deployment and low cost is still too early to decide. What is clear, however, is that the UK will either be behind in developing, or will not have, the societal benefits accrued by Germany through the development of an advocacy coalition and industrial value. The value attached to this over the coming years will influence future national and European policies.

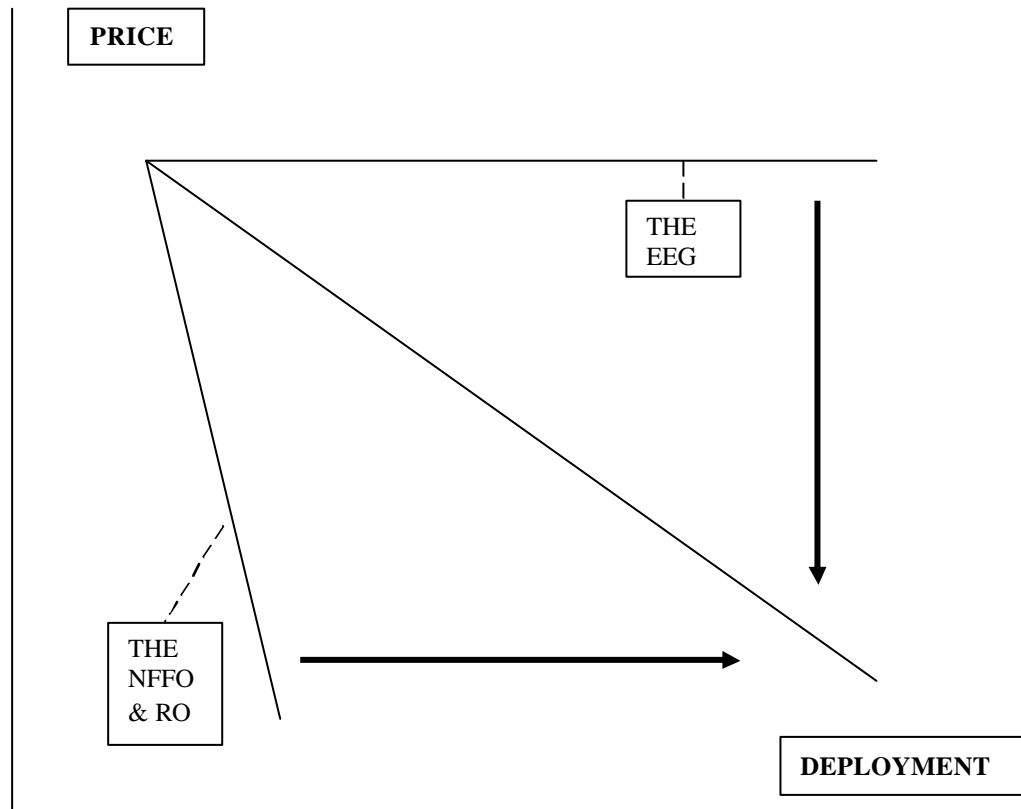


Fig. 2. Reaching Nirvana – high deployment, low cost renewables.

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