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QUALITATIVE ISSUES IN THE DESIGN OF THE GB FEED-IN TARIFFS

A report to the Department of Energy and Climate Change (DECC)

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QUALITATIVE ISSUES IN THE DESIGN OF THE GB FEED-IN TARIFFS

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Element Energy and Pöyry Energy Consulting have been appointed to conduct a study into the design options for a Feed in Tariff for the UK. This report summarises the qualitative work underlying the project, which was led by Pöyry. The work is accompanied by a techno-economic analysis of the UK Fit design options which is published separately.

Pöyry Energy Consulting is Europe's leading energy consultancy providing strategic, commercial, regulatory and policy advice to Europe's energy markets. Part of Pöyry Plc, the global engineering and consulting firm, Pöyry Energy Consulting merges the expertise of ILEX Energy Consulting, ECON and Convergence Utility Consultants with the management consulting arms of Electrowatt-Ekono and Verbundplan. Our team of 250 energy specialists, located across 15 European offices in 12 countries, offers unparalleled expertise in the rapidly changing energy sector.

Element Energy Limited is a dynamic and growing practice providing strategic advice and engineering consultancy in the low carbon energy sector.

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EXECUTIVE SUMMARY

Since 2002 the UK's principal form of support for renewable electricity generation has been the Renewables Obligation (RO). The RO has been relatively successful in increasing the deployment of large scale renewables, but the exploitation of small scale renewable electricity projects has remained limited. As a result, the UK's electricity system currently has a very low penetration of small scale renewables, relative to many other European countries.

The burden sharing arrangement agreed as part of the EU 2020 targets for renewable energy commits the UK to increase its share of renewable energy from an estimated 1.3% in 2005 to 15% by 2020. It is widely accepted that the electricity sector will play the larger part in achieving this goal than the heat and transport sectors, but to meet the targets, the sector will need significant growth in both large scale and small scale renewable electricity.

So the UK faces a significant and urgent need to increase the deployment of small scale renewable electricity generation. The Government plans to retain a revised RO as the main support mechanism for bulk electricity and has stated its intent to institute a system of feed-in tariffs (FIT) to address small scale renewables below 5 MW. In contrast to the RO which provides eligible generators with green certificates (ROCs) that can be sold to suppliers to meet their obligations, a feed-in tariff is a guaranteed payment to a renewable electricity (RES-E) generator for the electricity it generates. The technologies covered in the initial phase of the GB FIT scheme are likely to include onshore wind, solar photovoltaic (PV); hydro-electric and biomass (CHP and power only plants). Other technologies could be covered at a later stage.

This report provides a comprehensive review of how such a FIT scheme would work, explores the implications of different design options, and the experiences of other FIT schemes. It seeks to identify the appropriate FIT design, given the UK Government objectives, which would deliver effectively on the take up of small scale electricity producing renewables, while maximising cost efficiency and minimising distortions to the existing RO support system.

Our methodology involves three interrelated frameworks:

- a review of individual design parameter options, and an analysis of the pros and cons of the major design choices;
- detailed assessments of selected EU FIT schemes, in the form of case studies and review of their performance against policy objectives and best practices; and
- a comprehensive literature review.

Design parameters for a FIT scheme

FIT schemes have been successful in encouraging smaller scale generation in a number of European countries, such as Spain and Germany. In general, the success of a scheme depends on the careful design and selection of parameters, close alignment to policy objectives and market arrangements and its administrative performance.

In practice the schemes require careful design to ensure stability and to avoid excessive costs to electricity end users. There are three primary parameters which relate to the choice of tariff itself, notably:

- choice of fixed tariff or premium tariff;
- choice of stepped tariff or flat tariff; and
- tariff setting and adjustment mechanisms.

A fixed feed-in tariff is paid to renewable generators as an overall remuneration per unit of electricity generated, independent of the electricity market price. A premium feed-in tariff is a premium paid on top of the electricity market price. Tariffs can also be stepped or flat. In a stepped tariff the remuneration to a generator is differentiated according to all or a subset of the plant characteristics such as type of technology, scale, and local conditions or quality of the renewable energy resource. In a flat tariff the same level of remuneration is paid to RES-E plants irrespective of their specific cost drivers. Similarly, there is a wide range of protocols relating to choice of level of initial tariff support at the inception of the scheme, choice of tariff review period and the inclusion or exclusion of degression – the signalled reduction in the feed-in tariff levels over time to provide incentives for technology improvements and cost reductions of RES-E plants.

In addition, to these primary choices, there are other important but subsidiary design choices which affect the characteristics and effectiveness of FITs. These relate primarily to the administration of the FIT scheme and include:

- length of term of policy – the timeframe of guaranteed support to RES-E plants;
- grid connection policy – relates to the treatment of the connection and grid upgrade costs that occur due to new RES-E installations;
- purchase obligation – an obligation on grid operators or suppliers to purchase any electricity delivered to the grid from RES-E plants. Purchase obligation is typical for fixed tariffs but is rare for premium tariffs;
- forecast obligation – an obligation on intermittent RES-E plants to forecast their future generation output and notify the grid operator in advance – this is to facilitate effective management of the grid. An imbalance charge usually applies if a RES-E plant output to the grid does not match its forecasted value. Forecast obligation is usually applied with premium tariffs;
- capacity caps – the application of upper limits on the volume of new RES-E plants that can be installed in any given year;
- bonus incentives for innovative features – additional support to RES-E plants which fulfil a certain criteria or policy objective. Examples include incentives for repowering wind farms and rewarding high efficiencies for CHP plants; and
- choice of administration and operation of the scheme – the logistics for operating the scheme and recouping the subsidy.

The GB FIT scheme will need to select the most appropriate parameters of the choices outlined above. It will also need to consider local electricity market arrangements, overall energy and climate change policy framework, and energy policy objectives – all of which have an important bearing on its performance. In particular, the parameter choices should also be aligned with the policy objectives underpinning the FIT scheme which may include climate change (meeting the UK's 2020 renewable energy target and carbon reduction targets); security of energy supply; job creation from a green economy among other broader objectives and policy commitments.

We have reviewed each of the parameters in detail, and developed a framework which we use to assess existing European FIT schemes against policy objectives. The resulting best practices on which choices to make and what not to do are presented below – supporting evidence is detailed in the rest of the report.

Insights and recommendations for choices on design parameters

The choice of fixed vs. premium tariffs

For small generators, fixed tariffs are preferable for non-dispatchable renewable plants. The transaction costs of participating in the market, and the risk or uncertainty over electricity prices outweigh the benefit of easier grid management. However for dispatchable technologies (biomass- and gas-fired CHP) of a reasonable size, the premium option may provide appropriate signals to generate at times of high value.[1]

Choice of stepped tariff vs. flat tariff

The GB scheme should differentiate or step support by technology and scale in order to increase the economic efficiency of the incentive. Stepped tariffs provide support in line with the cost of deployment reducing the risk of overcompensating plants with efficient technologies or scale (excessive rents) and reducing the cost of support or burden for consumers. Differentiation or stepping also recognizes the future potential of the different technologies, some of which may be costlier in the near and medium term. Stepped support should be adopted if the policy intent is to support a basket of technologies and sizes. However to limit complexity of the scheme, support should differentiate by technology and scale for all technologies, but limit any further steps beyond this – except for PV and biomass where a further layer may be considered such as building integrated vs. field-based PV systems or the diversity of fuels for biomass plants.

Setting the initial tariff level

Financial support will need to be set at a level that is sufficient to deliver investment, but which does not over-compensate investors. Experiences of other schemes suggest that various RES-E technologies have a minimum remuneration threshold that is necessary to initiate deployment – beyond this threshold; remuneration does not necessarily correlate with policy effectiveness.

The initial feed-in tariff level should at a minimum apply a rate of return, equal to the hurdle rate of a standard investor class to the specific cost of generating electricity from the RES-E plant.[2] Data on existing generation plants, where they exist, could be useful in determining the initial tariff level. However, with the recent volatility seen in equipment costs the setting of the initial tariff level needs to factor in possible short-term equipment cost movements.

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1 The Renewable Energy Association (REA), for instance and other stakeholders in the GB market have recommended what this report classifies as a ‘modified’ premium tariff to encourage greater on-site use of RE electricity – according to the REA proposal, all RES-E generators would be paid a fixed-renewable tariff for all energy produced, however they would be entitled to an additional export price set at a level established between the supply company and the beneficiary and subject to market competition (see REA and stakeholder working groups, Renewable Electricity and Heat Tariffs – Preliminary recommendations on their implementation from the renewable energy industry, March 2009).

2 See Annex G for a discussion on defitions and diversity of investor classes and its impact on the GB FIT scheme.

In general, a FIT scheme should provide appropriate signals to encourage the deployment of the most cost effective technologies and resources first, but support the full basket of technologies which can be reasonably utilised – it may be beneficial in the long run for FIT schemes to also encourage the diffusion of immature and less competitive technologies, as evidence suggests that learning and scale economics lead to future cost reductions and more competitive portfolio of RES-E technologies. In addition, inflation and exchange rates should be considered in establishing the initial tariff level and subsequent revisions, as this affects power generation costs.

Tariff setting and adjustment mechanisms

Tariff adjustment protocols deal with the possibility of incorrectly estimating investors' response to the initial tariff level, and – when the GB FIT is up and running, adjusting tariffs to reflect the changes in cost of generation due to innovation or changes in cost of components. Tariff adjustment process reviewed in the report includes protocols on:

- tariff review periods and process;
- exclusion or inclusion of degression; and
- duration of tariff support or guarantee period.

Revisions of the scheme should consider only new installations when reviewing, adapting or changing the scheme. Existing investors need confidence that the government will not change the scheme for existing projects, once they have made their investment, otherwise the hurdle rate at the start will be higher to reflect the additional policy risk. An interim review after the first year to ensure overall design and support levels are driving the market as intended is seen as appropriate, with formal reviews every 3-4 years thereafter, perhaps with an interim minimum adjustment if necessary.

Implementing a sensible and clearly communicated degression rate can enforce technological learning over time. For technologies with global learning rates (e.g. photovoltaics), degression should rely on global technology cost reductions, while for smaller more localised markets (e.g. Biomass CHP), feedback from market stakeholders on an appropriate rate of degression should be considered.

There is no 'right' timeframe for overall support, however it needs to be for a period sufficient to provide stable planning horizons and financing arrangements – 10-15 years is an appropriate starting point. It is possible to consider shorter payback periods for instance 5-10 years, especially for households and other small scale investors who may be disincentivized by high discount rates and high upfront capital costs. Financiers are likely to attach higher risk premiums to shorter support periods since there would be greater economic impact in the case of shorter support periods if, for example, an investment were to experience lower than expected availability during the first few years of commissioning.

Subsidiary parameter choices

Selected best practices on subsidiary parameter choices reviewed include:

- inclusion of capacity caps;
- bonus incentives;
- interaction with market arrangements and broader regulatory framework; and
- administration and operation of the scheme.

Capacity caps should be avoided unless set sufficiently high so as not to artificially constrain uptake. Capacity caps if poorly designed could lead to a boom and bust scenario as the example of solar PV deployment in Spain illustrates – in 2008, more than 2.5GW was installed, a boom trigerred by generous tariffs, this is expected to decline to 500MW in 2009 due to lower tariffs and a cap. However, a cap higher than the required and/or predicted uptake could function as a backstop to constrain subsidy spend (in this regard a capacity degression works better than a cliff edge or automatic review cap).

Complementary support policies could be provided targeted at specific technologies – for example, additional incentives for combined heat and power plants (CHP) with extremely high efficiency. Bonus incentives can enhance the prospect of achieving specific policy objectives, such as, driving technological innovation. However, the potential benefits must be weighed against the additional administrative complexity which they would introduce in the FIT scheme.

The scheme should allow conformity with the power market structure and other policy instruments or targets. The GB FIT scheme will need to accommodate the existing carbon reduction commitments, the RO, the Renewable Heat Incentive scheme (RHI) and other support schemes to ensure efficiency and cost effectiveness. The FIT for instance should be tapered for technologies currently successfully supported by the RO, so that the support levels provided approach the RO values as the RES-E installation size get larger, with convergence at the 5 MW threshold. Carefully tailored interactions should minimise market distortions and ensure the FIT can be adjusted to changes in the market situation.

The administration of the scheme is likely to be driven by the UK context. In most schemes, the grid operator is usually in charge of administration, however since the DNO in the GB context is not licensed to generate or purchase electricity – short of amending their licenses, payments and administration of the scheme may involve suppliers rather than DNOs or grid operators as is common in Europe. The suppliers could thus be responsible for conducting the financial transactions – paying generators and recouping payments from electricity end users. Such an arrangement would be complemented by a pre-defined arrangement between suppliers to deal with issues relating to asymmetrical RES-E distribution or a separate administrator to handle inter-supplier reconciliations. Most suppliers already have the transactional capacity, and the experience of offering buy back tariffs. However there are other arrangements for administering the scheme worth exploring.

Best practices in the UK context

Table 1 sets out specific recommendations on the choice of parameters for each of the technologies covered by the GB FIT scheme, building on the generic insights highlighted above. These recommendations should be viewed in the context of two caveats.

The GB FIT under consideration is unique in its focus on small scale generation. With the exception of Italy which allows small scale generation projects below 1 MW to choose between a FIT and green certificates, all other schemes in Europe are applied across all scales. As a result, it is difficult to distinguish between those best practices that apply across all scales and those which are particularly suitable for small scale generation and would therefore be more suitable in the UK context. Similarly differences in market arrangements between the UK and other countries means that some of the best practices outlined will need to be modified to fit into the UK context.[3]

Beyond the aforementioned issues, the rest of the report explores the implications of different design options, how the FIT would work and provides a comprehensive review of best practices from the experiences of other countries and in the literature for lessons in the development of a GB FIT scheme.

3 As noted, in most schemes reviewed, the network operators are responsible for the administration of the scheme. In the UK, the DNO who would be similarly responsible are not licensed to generate or purchase electricity – short of amending their licenses, this implies that a purchasing obligation would be difficult to implement, unless the obligation is transferred to suppliers. It also implies that payments and administration of the scheme may involve suppliers rather than DNOs or grid operators as is common in Europe.

Table 1 – Conclusions and insights on choice of parameters[4]

Design parameter	Design parameter	Onshore wind	Solar PV	Biomass CHP	Small hydro	Biogas	Wave and tidal
Primary parameters	Choice of tariff - fixed vs. premium	Fixed	Fixed	Fixed/Premium	Fixed	Fixed/Premium	Fixed
	Choice of flat vs. stepped tariff	Stepped	Stepped	Stepped	Stepped	Stepped	Stepped
	Technology differentiation	Yes	Yes	Yes	Yes	Yes	Yes
	Scale/ Local condition differentiation	Scale	Rooftop/ Façade (Building integrated) vs. Open space installations	Scale/ Fuel	Scale	Scale	None
	Apply Degression	Yes	Yes	Yes	Yes	Yes	Yes
	Level of degression	Medium	High	Low	Low	Low	Low
	Review period	3 yrs. (1st review after one year)	3 yrs. (1st review after one year)	3 yrs. (1st review after one year)	3 yrs. (1st review after one year)	3 yrs. (1st review after one year)	3 yrs. (1st review after one year)
	Setting initial tariff support level	Based on technology cost and hurdle rates.	Based on	Based on	Based on	Based on	Based on

4 The pros and cons of each parameter design option and the best practices from other countries and literature that informs our recommendations are discussed in detail in Section 2 and 3

		Apply reference plant approach	technology cost and hurdle rates. Apply reference plant approach	technology cost and hurdle rates. Apply reference plant approach	technology cost and hurdle rates. Apply reference plant approach	technology cost and hurdle rates. Apply reference plant approach	technology cost and hurdle rates. Apply reference plant approach
Secondary parameters	Length of guarantee	lifetime of plant or 15-20 years	lifetime of plant or 15	20 years	lifetime of plant or 15	20 years	lifetime of plant or 15
	Capacity cap	No	No	No	No	No	No
	Purchase obligation	Yes	Yes	Yes / No (based on trade-off between investors' risk and grid management costs)	Yes	Yes / No (based on trade-off between investors' risk and grid management costs)	Yes
	Forecast obligation	No	No	No	No	No	No
	Bonus incentives	Repowering	None	Fuel efficient (CHP)	None	None	None
	Grid connectionpolicy	Shallow[5]	Shallow	Shallow	Shallow	Shallow	Shallow

Source: Pöyry Energy Consulting / Element Energy

5 In a shallow connection arrangement, RES-E plants pays for only the cost of equipment needed to connect to grid; upgrade cost are borne by the grid operator, who usually recovers by applying 'use of system' charges.

1. INTRODUCTION

1.1 Background

The UK government has committed to meeting a target of 15% of the UK's energy needs through renewable energy sources by 2020, and it is widely accepted that the expansion of the renewable electricity sector will be foremost in achieving this goal.[6]

Currently, renewable electricity supply in the UK is supported by a quota obligation tradable certificate mechanism, the Renewables Obligation (RO), which was introduced in 2002. The scheme has delivered some success in the deployment of large scale renewables; however the exploitation of small scale renewable electricity projects has remained low.

The Department for Energy and Climate Change (DECC) has commissioned Element Energy and Pöyry Energy Consulting to carry out a study to analyse the implications of a GB feed-in tariffs (FIT) system. The analysis is to explore the opportunities for a FIT system for renewable electricity generation below 5MW and low-carbon electricity generation below 50kW.

FIT schemes have been successful at encouraging renewable generation in a number of European countries, Germany being most notable.[7] However, such systems require careful design to ensure their robustness in limiting the potential for booms and busts in the market and avoiding excessive costs to electricity end users.

The deliverables of the study consist of two main components: 1) a qualitative analysis of the most important design parameters and issues for consideration to implement a successful FIT scheme and, 2) a quantitative model that links the main design parameters, which DECC would be able to adapt to achieve their desired policy outcome. This report is the main deliverable under 1) above.

1.2 An introduction to FITs

1.2.1 What are they, where are they in place?

A feed-in tariff is a guaranteed payment to a renewable electricity (RES-E) generator for the electricity it produces. This is usually accompanied by the requirement for the electricity grid

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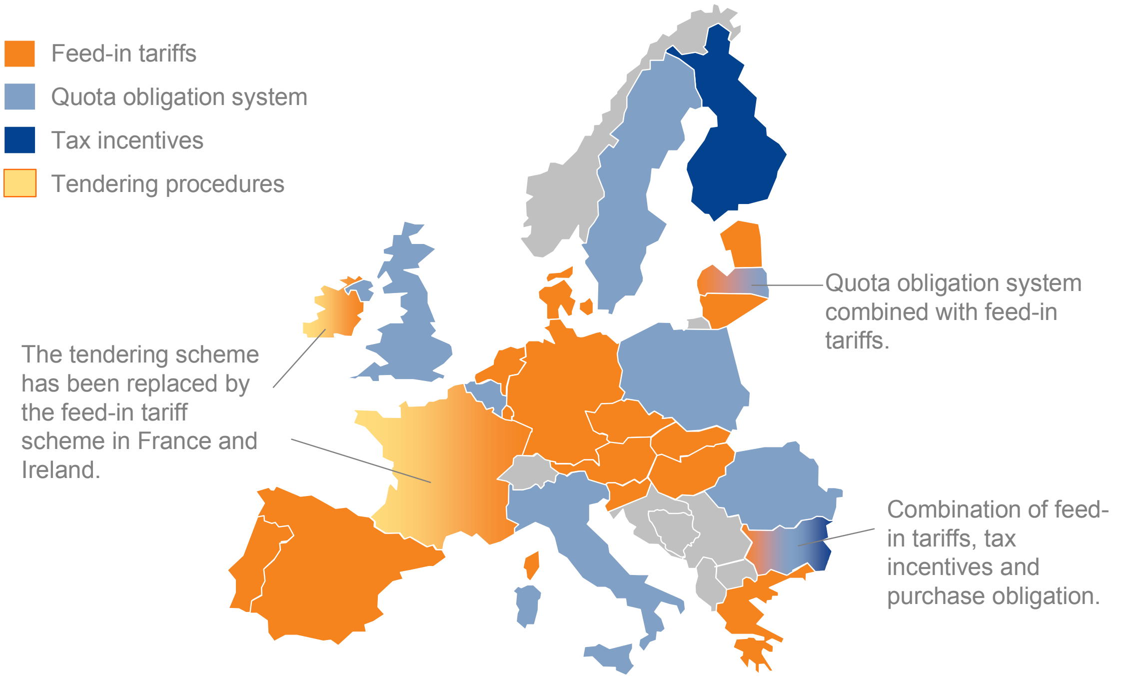
6 The European Council meeting of March 2007 committed the 27 EU Member States to a binding target for 20% of the EU's energy needs coming from renewables by 2020 as part of the post-Kyoto arrangement. In December 2008, the European Parliament and Council agreed to a Renewable Energy Directive, which confirms the previously agreed target for the EU and sets out the required apportioning into national targets for each Member State. Under the burden sharing arrangement, the UK's renewables target is set at 15% of its total energy by 2020, rising from an estimated 1.3% in 2005.

7 Renewable energy uptake in Germany has increased from an installed capacity of 4,651 MW in 1990 at the inception of the Energy Feed-In Law (the precursor to the EEG) to 34,018 MW as of 2007 (See Renewable energy sources in figures, German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU), June 2008)

to accept the electricity generated. Since the cost of electricity from fossil fuel based power generation technologies have traditionally been cheaper than from renewable sources, payments to RES-E plants per unit electricity are typically greater than the market price of electricity, to enable the plants to operate economically.

Feed-in tariffs are applied extensively across Europe and as assessed in Section 3, have achieved varying levels of success in increasing the rate of uptake in renewable electricity supply. Figure 1 below highlights the countries in Europe which apply FIT schemes in contrast to those applying other RES- E support mechanisms.

Figure 1 – Main policies for support of renewable electricity across Europe



Source: Pöyry Energy Consulting

As Figure 1 shows FITs are the most prevalent RES-E support mechanism applied across Europe – nineteen of the EU-27 countries use FIT, six countries have implemented quota obligation with tradable green certificates (TGC), while only two countries have opted for tax incentives and investment grants as their main RES-E support instrument.

In a quota obligation support scheme, an obligation is placed on an electricity supply company to source a specific fraction of its electricity from renewable energy sources, and a penalty is applied for failure to meet the obligation. In essence, this mechanism acts to create a market for renewable electricity, allowing competition amongst different RES-E plants to meet the obligation. The underlying principle is that competition in the market will drive down the costs of supplying renewable electricity and thus minimises the costs to end users for meeting renewable energy targets. Therefore, in theory obligation/ tradable certificate schemes should be more economically efficient than feed-in tariff schemes. However, as suggested in the IEA review of RES-E support mechanisms[8] evidence suggests that well-designed feed-in tariffs can be superior to obligation mechanisms and other support schemes in terms of effectiveness and cost-efficiency.

The uncertainty of the outcome of competition under a quota obligation scheme, in terms of volume and price, increases the risks to RES-E plants and raises their cost of capital and, consequently, their overall costs. The risk and the related additional costs associated with the obligation mechanism are sometimes sufficient to outweigh the benefits from competition inherent to the system. Table 2 and Table 3 below summarise the respective pros and cons of an obligation mechanism and a FIT scheme.

It is worth noting that there are other barriers to uptake for instance planning approval and grid access (which may help to explain the difference in performances between obligation-based support mechanisms and FIT schemes).

For the purposes of support for small scale renewables the FIT approach is seen as more appropriate by the UK Government which can be justified solely on the grounds of simplicity and increased investor certainty.

Table 2 – Pros and cons of a FIT scheme

Pros	Cons
Risk reduction for investors: RES-E plants are guaranteed fixed prices for fixed periods, thus reducing volume and price risks. In addition, RES-E plants are typically not subjected to balancing risk and network companies are usually compelled to take all electricity.	Potential for excessive margins for developers or equipment manufacturers and direct signalling of what cost the market can bear: The fixed price over time implies that it is difficult to pass on the benefits of increased technological efficiency to consumers. Tariff degression and regular reviews of pricing policy are ways to address this. However, there is no guarantee that reductions will match the actual improvements in the technology.
	Market prioritization: There is interference with market operation due to the fact that the outputs from RES-E plants are guaranteed. This impact on the ability of "traditional" generators to compete in the electricity sector, and can be a problematic issue where governments have committed to maximising competition in the markets.
	Network balancing: Network operators are compelled to accept all electricity from RES-E plants, regardless of the electricity demand,

8 Deploying Renewables: Principles for Effective Policies, IEA, 2008

	which can lead to network balancing problems and increased grid operation costs.
Since different technologies develop at different rates, application of technology specific tariffs could encourage those far from the market to move closer. The balance of evidence suggests that this provides long term benefits in terms of developing more competitive technologies.	The level of RES-E capacity exploitation is subject to the market, that is, it depends on investors' response to tariff signals. It is very difficult to predict the number and scale of investments that will be attracted by the available prices; hence it is challenging to predict the overall costs of the mechanism in either the short- or long-term. This can be unattractive to government and consumers/taxpayers. Caps on capacity is one way of dealing with this issue.

Source: Pöyry Energy Consulting

Table 3 – Pros and cons of an obligation mechanism

Pros	Cons
In theory, should be more effective and cost-efficient as competition is an inherent feature of the mechanism.	There is significant risks on electricity sales volume (no guarantee to sell all electricity produced, due to competition) and price (depend on the market for both electricity and tradable certificates). In practice, increase risk and related additional costs may be sufficient to outdo benefits from competition inherent in system. Butler et al (2004)[9], for example, suggest that

9 Butler, L., Neuhoff, K., Comparison of Feed In tariff, Quota and Auction Mechanisms to Support Wind Power Development, Cambridge Working Paper in Economics, 2004.

	the price paid for wind power under the UK's RO is higher than the remuneration under the German's FIT.
It has been suggested that quota based schemes are more efficient in achieving specific goals for renewable energy capacity.	Mechanism tends to support only the technologies that are close to the market when it is introduced. Technologies outside the mechanism are likely to become less and less competitive, and thus are never developed. Technological innovation is therefore effectively penalised. One solution is to provide additional support outside the mechanism which creates a more complex set of arrangements.

Source: Pöyry Energy Consulting

1.3 Objectives and characteristics

The main objective of a FIT is to increase the amount of electricity produced from RES-E technologies, by increasing their installed capacity. However, a FIT objective is typically set within the context of achieving wider policy goals.

1.3.1 Policy objectives for a FIT scheme

The objectives of a typical FIT scheme include but are not limited to:

- environmental imperatives – in the UK context, these would relate to the obligation to reduce green house gas (GHG) emissions under the Kyoto protocol, and the establishment of the 15% renewable energy target for the UK by 2020;
- security of supply – in addition to diversifying the electricity portfolio, the proliferation of domestic renewable electricity supply would also reduce reliance on imported energy, and hence enhance the security of energy supply;
- economic and industrial policy considerations – wider economic and industrial policy issues may include creating a domestic renewable energy industries and jobs in the supply chain, as well as driving technological innovation in the area; and
- behavioural change – involves enhancing the social acceptance and uptake of renewable electricity technologies and in corollary wider carbon reduction commitments

1.3.2 Framework governing recommendations

In addition to achievement of policy objectives, such as highlighted above, there are several features common to the most successful feed-in tariff schemes. These include:

- low administrative and regulatory barriers (simplicity and transparency);
- high certainty to investors (stable and long term policy framework); and
- high cost efficiency.

These key characteristics are generic for successful FITs geared at exploiting both large scale and small scale renewable electricity and are a useful benchmarks in reviewing and assessing which parameters should be considered: in evaluating the performance of selected FIT schemes in Europe; and in reviewing best practices identified in the literature review.

1.3.2.1 Low administrative and regulatory barriers

The administrative barrier of a feed-in tariff scheme relates to its degree of complexity and clarity, which has a significant bearing on its effectiveness. In general, the simpler and more transparent a FIT is, the greater will be investors' confidence and, consequently, the higher the investment security. Conversely, FIT schemes that are administratively more complex and less transparent will generally increase the perceived risks to investors, and reduce investment security. Low regulatory barriers also imply compatibility with current market and policy arrangement, which tends to improve the effectiveness of FIT schemes, as this reduces the relevant transaction costs for RES-E investors.

1.3.2.2 High certainty to investors

FIT schemes may also reduce the risks on volume and price by guaranteeing RES-E plants fixed payments per unit production over fixed periods. A FIT scheme with a stable and long term policy framework would, all else being equal, be more investor friendly than one with a short policy framework. To put this differently, stable policy frameworks guarantee support over longer periods which further reduce the risks on price and volume and enhance investment stability.

1.3.2.3 High cost efficiency

According to the IEA[10], the remuneration level of a FIT scheme does not necessarily correlate with its policy effectiveness. Successful FIT schemes achieve high effectiveness at a minimal cost of deployment. In essence, this means reducing the cost to end users, who ultimately have to meet the FIT implementation cost, as well as guarding against excessive rents for RES-E investors.

In line with the principle of economic efficiency, it is imperative for successful schemes to encourage the exploitation of the most cost effective renewable resources and technologies first. However, it may be beneficial in the long run for FIT schemes to also encourage the diffusion of immature and less competitive technologies, as evidence suggests that learning and scale economics lead to future cost reductions and more competitive portfolio of RES-E technologies.

1.4 Approach to the study

The policy objectives and features of successful FIT schemes identified above, are used in the rest of the report as a framework to review and identify the lessons applicable to the UK, and in particular in assessing and comparing the performances of selected case study FIT schemes across Europe. Our approach to the study is detailed in Figure 2 below and involves three interrelated frameworks, namely:

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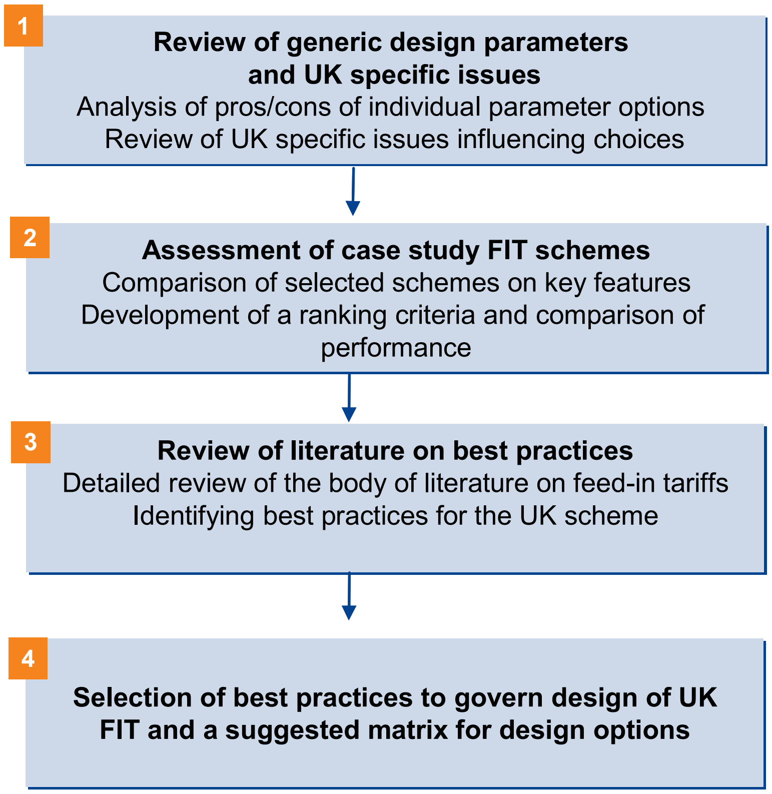
[10] Deploying Renewables: Principles for Effective Policies, IEA, 2008.

- a review of individual design parameter options, and an analysis of the pros and cons of the major design choices;
- detailed assessments of selected FIT schemes, in the form of case studies; and
- a thorough review of the body of literature on feed-in tariffs.

Figure 2 – Framework of the study



Source: Pöyry Energy Consulting

The intent of the framework and the larger aim of this report is to distil lessons from other countries experiences with FITs, as well as suggested best practices from the literature, to be integrated with our individual assessments in deriving insights on appropriate choice of FIT design parameters for the UK.

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2. INTRODUCTION

We characterise FIT schemes as permutations of the following three major design parameter choices:

- choice of fixed tariff or premium tariff;
- choice of stepped tariff or flat tariff; and
- choice of tariff setting and adjustment mechanisms

This section of the report presents an overview of the fundamental design options available in developing a FIT scheme and discusses the respective strengths and limitations of each choice.

2.1 Fixed tariff versus premium tariff design

A feed-in tariff can be paid to RES-E generators as an overall remuneration (the *fixed tariff*) or alternatively as a premium that is paid on top of the electricity market price (the *premium tariff*).

2.1.1 Fixed tariffs

The fixed tariff option involves a fixed remuneration, which is independent of the electricity market price, paid to RES-E plants, per unit of electricity they deliver to the grid. Most EU schemes currently apply a fixed tariff model.

2.1.1.1 Types and examples

There are two variations of fixed tariff which relate to inclusion or exclusion of demand orientation:

- *Fixed tariff without demand orientation* – this is a fixed tariff scheme without demand orientation, where one fixed level of support applies irrespective of the time of day or month. Most schemes providing for fixed tariffs such as Germany, for apply fixed tariffs without demand orientation.
- *Demand oriented fixed tariff* – in this variant, separate support levels are available for different time periods (e.g., for day/night, summer/winter) corresponding to peak and off-peak electricity demand intervals. The aim is to provide price signals for RES-E plants to respond to high peak period prices. However, operators of most RES-E plants (e.g., wind and solar) have little or no influence on their supply profile and therefore most plants would not be able to take advantage of peak prices. This type of fixed tariff is rare and is currently applied in Slovenia.

2.1.2 Premium tariffs

Premium tariffs involve payment of a premium (also called a green bonus) to RES-E plants on top of the electricity market price they receive for the electricity they deliver to the grid. Premium tariffs are currently applied in Spain, the Czech Republic, Slovenia, the Netherlands, Denmark (for onshore wind energy) and, most recently, Estonia.

2.1.2.1 Types and examples

There are two variations of premium tariffs:

- Electricity market price plus a set absolute figure – this is the more widely used variant of the two premium systems; and
- Electricity market price plus a set percentage of the market price – this variant was applied in Denmark for plants connected to the grid between 2003 and 2004, however its principal drawback is that it increases the payments to RES-E plants rather than reducing the additional incentives provided when electricity prices are high, and may not provide enough additional top-up when prices are low, thus magnifying the volatility of relying on the electricity market for support.

2.1.3 Comparing and contrasting fixed and premium tariffs

2.1.3.1 Fixed tariffs

The main advantage of a fixed tariff is that it offers the highest level of certainty to investors, as the overall remuneration is constant[11] over the contract period. This certainty reduces the risk associated with the investment and lowers investors' hurdle rate. In addition, a fixed tariff lowers the transaction costs for RES-E plants owners, as they are usually not obliged to participate in the market or to minimise their impact on balancing and demand management. This is especially important for very small RES-E plants such as domestic solar PV, which are likely to be delivering only a few kilowatt-hours to the grid.

The primary disadvantage of a fixed tariff is the lack of a price signal to incentivise generation at times of high value and, due to the normal combination with a purchase obligation, to actively manage system balancing costs.

2.1.3.2 Premium tariffs

Premium tariffs are more compatible with the liberalised electricity markets than a fixed feed-in tariff; it allows better and more efficient assignment of the grid costs, particularly as it relates to balancing and demand management. In addition, in the specific context of the UK situation, greater compatibility with the liberalised electricity market means that the premium FIT is more aligned with the existing RO mechanism, which should improve interaction between the two schemes.

The main disadvantage of the premium option is that the risk for RES-E investors is larger because the total level of remuneration is not determined in advance and there is usually no purchase obligation as is typically the case with the fixed option. To offset this, the remuneration of the premium option is generally set higher than that of the fixed tariff option in order to compensate RES-E investors for the higher risks associated (if the same investment in new installations is to be achieved).[12] This in turn implies higher costs for the electricity

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11 Note that constant does not imply one fixed value. In a demand oriented fixed tariff, separate tariff levels are available for different periods. These levels remain constant for the entire contract period.

12 In Spain which provides RES-E plants with the option of a fixed or premium tariff, the fixed tariff for onshore wind is set at 7.3 € cents/KWh. In comparison the premium tariff is set at 2.9 €

consumers, especially if the remuneration levels of the fixed and premium options differ significantly. This is particularly true in situations where the renewable electricity technology is not dispatchable (i.e. cannot choose which times to generate either in response to price signals or to reduce costs via some form of centralised control).

Table 4 below outlines the main strengths and weaknesses of a fixed tariff design in relation to a premium tariff system.

Table 4 – Pros and cons of a fixed and premium tariff designs

Fixed tariffs: pros	**Cons**
Investors have high level of certainty, as the support is independent of the electricity market price, and the overall remuneration is defined over the entire support period. This reduces the risks associated with the investment and lowers the hurdle rate.	Fixed tariffs are less market oriented and therefore it is more likely that they will cause more market distortions. Fixed tariffs are less demand oriented than a premium tariff, even considering the demand oriented variant, hence there is less incentives to deliver electricity to the grid during peak periods.
The purchase of RES-E output is usually guaranteed and there are typically no forecast obligations. This lowers the transaction costs for generators, since no balancing and demand management costs apply.	The lack of obligation on the RES-E plants to manage their impact on the grid increases the system's balancing and demand management costs.
Premium tariffs: pros	**Cons**
Higher compatibility with the liberalised electricity markets, which tends to result in less market distortion. Higher compatibility also implies greater alignment with the existing RO mechanism, which should minimise interaction problems (specific to the UK). In addition, market participation prepares generators for the expectation of the FIT policy framework elapsing, in which case they would have to participate in the market.	There is no purchase guarantee and therefore less investment security, which is usually offset by applying higher overall remuneration in comparison to fixed tariffs. (Investors generally require higher returns to put up with the complexity of extracting revenues from many sources, and the added volatility in revenue) In most schemes, RES-E suppliers have to participate in the electricity market and have balancing and demand management obligations – this increases the transaction costs for RES-E investors.

cents/KWh (this excludes the electricity price which averaged 6.6 € cents/KWh in 2008) – for a total remuneration of 9.5 € cents/KWh. A higher level of remuneration for premium tariffs is common for all countries that provide both options.

More demand oriented, and hence more strongly incentivises RES-E plants to supply electricity during peak periods. In other words, premium systems provide greater incentives for RES-E plants to focus on higher-premium peak supply.
(although operators of wind and solar plants have little influence on supply profiles)
Source: Fraunhofer ISI, EEG and Pöyry Energy Consulting

2.1.3.3 Innovative types of premium tariffs

To mitigate against the increased risks due to the volatility of electricity price and the associated extra costs for electricity consumers in the premium option, some schemes have introduced collars (upper and lower limits) on the overall remuneration levels. In Spain, for example, a capped premium was introduced in 2007. Another possibility is a premium varying with the electricity market price, as applied in Denmark. A floor (bottom limit) can also be introduced in order to compensate investors for the risk of falling electricity prices. The application of varying premiums or limits negate some of the advantages of the premium option, for example, the incentive to feed electricity into the grid in a moment of high demand (and a high price) is reduced.

In general, to encourage participation in the market, the level of premium is chosen so that the overall remuneration under this option is higher than in the case of a fixed tariff option. This is logical given that the risks associated with the premium scheme are higher, as established below.

Some countries, including Spain and the Czech Republic, have opted to give RES-E generators the choice of deciding a tariff according to the premium or fixed design, while in very few jurisdictions, such as Slovenia, RES-E generators are allowed to sell a part of their electricity on the market receiving a premium on top of the market price and another part to the grid operator receiving fixed tariffs.

Some stakeholders in the UK have recommended a modified premium scheme where all RES-E generators would be paid a fixed-renewable tariff for all energy produced, however they would be entitled to an additional export price set at a level established between the supply company and the beneficiary and subject to market competition.[13] The premium in this sense would be high enough to be a stand-alone fixed tariff for off-grid and small scale generators allowing less dependence on electricity price which would be subject to market competition.

In general, the premium tariff design is more compatible with the existing UK market arrangement, where generators bid to supply electricity into the wholesale market or make bilateral contracting arrangements for offtake.

[13] REA and stakeholder working groups, Renewable Electricity and Heat Tariffs – Preliminary recommendations on their implementation from the renewable energy industry, March 2009.

Key insights on fixed and premium tariffs from best practices

For a FIT scheme aimed at exploiting the up take of small scale renewable electricity projects, as is the GB FIT, it is best practice to apply the fixed tariff option for non-controllable RES-E generation. The extra transaction costs for implementing a premium tariff for these generation types (i.e., small non-controllable RES-E), the cost of forecasting and the additional risks and uncertainty typically outweigh the grid management benefits to be realised from a premium system.[14]

However the transaction costs of participating in the market are usually small for controllable RES-E generation (of a given size – their outputs can easily be predicted, which minimises their associated balancing and demand management costs). The premium option could be applied for controllable RES-E generation, since it provides the right market signals for the RES-E plants at the expense of only a minimal transaction costs to participate in the market.

2.2 Stepped tariff versus Flat tariff design

One of the main issues with feed-in-tariffs is that the costs of a technology vary with specific characteristics. In particular:

- differences between technologies (wind, solar, hydro, biomass, etc.); and
- differences within technologies (e.g., onshore wind vs. off-shore wind, fuel type for CHP and biomass plants, etc.). Examples include:
  - variations in scale (due to economies or diseconomies of scale);
  - variations in resources used or local conditions – the quality of the renewable energy resource (e.g., the level of wind speed at sites), specific location of plant (e.g., siting a PV plant in a sunnier part of the country).

2.2.1.1 Differentiation across technologies

Feed-in tariffs are generally designed to provide technology-specific tariff levels. This is important if the policy intent is to support more than one RES-E technology, since power generation costs vary across different RES-E technologies.

14 The transaction costs of market participation and the real or perceived higher risk of premium tariffs among households and small scale plants may exceed savings in balancing costs. There is no firm evidence to support this finding– in general most studies on the impact of increased penetration of distributed generation suggest higher balancing costs as penetration increases. One way of indirectly measuring the additional balancing costs is the cost of increase in secondary load following reserves. Several studies suggest balancing costs of €1–3/MWh for a wind power penetration of 10% of gross consumption and €2-4/MWh for higher penetration levels. On the other hand, the costs for participating in the market are likely to include tangible costs such as contracting with a supplier, forecasting supplies (if there is a forecast obligation) but also intangible factors such as hassle costs that vary significantly across households.

2.2.1.2 Differentiation within a technology

It is also possible to differentiate tariffs within a technology – either on the basis of scale (see below), fuel type, or local condition. For example, biomass plants may receive different tariffs depending on the fuel types used.

2.2.1.3 Differentiation by scale

Tariff differentiation can be applied according to the installed capacity of the RES-E plant or amount of electricity generation it can deliver to the grid over a specific period. In France, Germany, Luxembourg, Slovenia, and Spain, tariffs are differentiated according to installed capacity, while in Austria, it is by the quantity of electricity generation.

2.2.1.4 Differentiation by quality of resource or local condition

There are two modes in which differentiation by local conditions have been applied:

- Quality of renewable resource (e.g., wind yield, solar radiation etc.) – for example, in Germany a formula linked to the wind speed ensures that wind farms have higher tariffs in lower wind speed regions and so can be viable for development, whilst still ensuring more attractive overall returns for the better wind sites.[15]
- Specific location of plant – in Greece, for example, higher tariffs are offered for installations located at the autonomous islands, which are not connected to the electricity grid of the mainland.

2.2.2 Flat tariffs

In a flat tariff the same level of remuneration is paid to RES-E plants irrespective of their technology differences, their scale, and their local conditions. In other words, RES-E plants of a specific technology receive the same level of remuneration irrespective of the specific costs of the plant (determined by its intra-technology type, its scale, and local conditions). Flat tariffs are only applied in a few countries, including Estonia and Hungary.

2.2.3 Stepped tariffs

In a stepped tariff the remuneration to a specific RES-E plant is varied according to one or more of the characteristics discussed above (scale, local condition, and fuel type).

2.2.3.1 Types and examples

The main types of stepped tariffs are associated with:

- Tariff level depending on location condition – examples include higher tariffs for PV plants integrated in the façade of a building versus open space installations, or reduced

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15 In Germany, the energy outputs of large turbines are compared against a reference turbine, and machines with lower outputs receive higher payments. The higher payments are set so that although they provide good returns on investment for a wide range of sites, the highest returns are always available at high wind-speed sites. This ensures that turbines are preferentially deployed at the most cost-effective sites.

tariff for wind plants with generation output over a reference level – both applied in Germany.

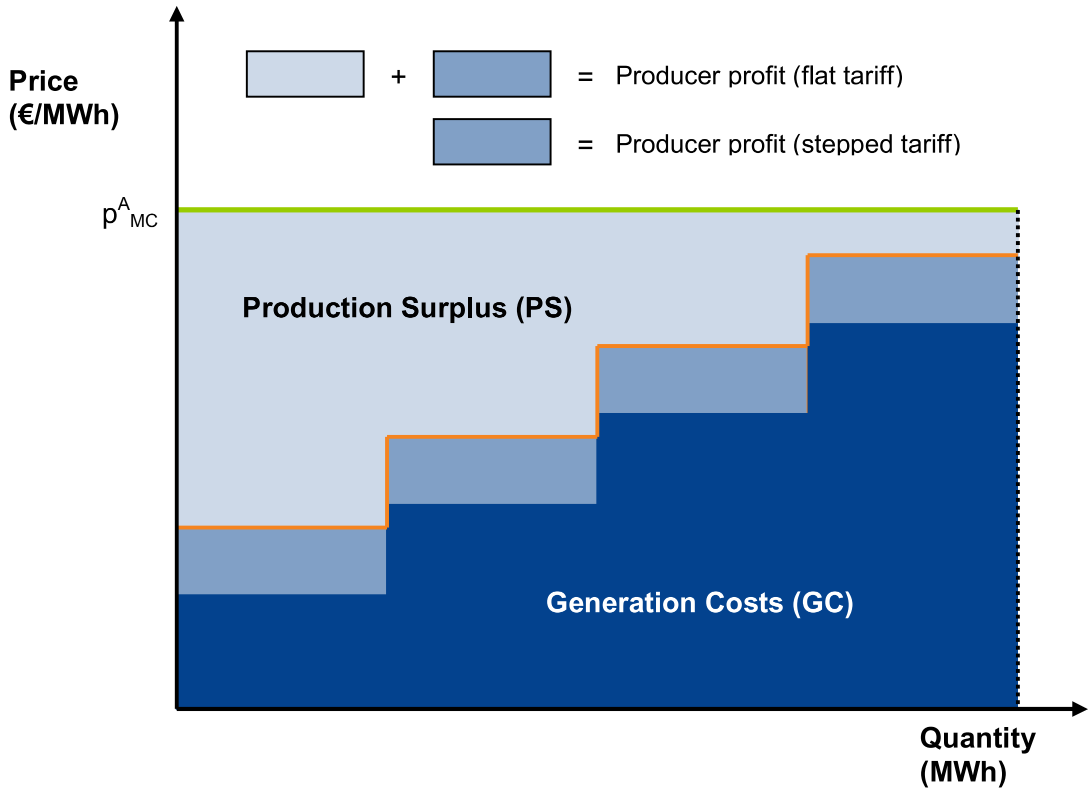
- Tariff level depending on plant size – this is common for most FIT's for solar PV.
- Tariff level depending on the specific biomass fuel type for biomass plants – applied in the Czech Republic.

2.2.4 Comparing and contrasting stepped vs. flat tariffs

2.2.4.1 Stepped tariffs

Stepped tariffs allow the variations in the RES-E plant costs across technologies and within a technology to be accounted in the support mechanism and therefore are more geared towards cost efficiency. It enables policy to reflect the lower generation costs due to economies of scale or the location of a plant. The stepped tariff option therefore has the advantage of being able to moderate the profits to RES-E project developers (minimising the risk of over-compensating projects) and the burden to electricity consumers, who ultimately pay for the subsidies as highlighted in Figure 3 below.

Figure 3 – Stepped vs. flat tariff design



Source: Feed-In systems in Germany and Spain, Ragwitz et al

Figure 3 shows that the generation costs of RES-E plants increases as the overall quantity of RES-E resource being exploited increases. This is based on the assumption that the most cost effective resources will be exploited first. The figure further highlights that with a flat tariff, the profit to RES-E investors (difference between the tariff level p^{A}_{MC} and the generation cost) would be much higher for RES-E plants with lower generation costs. If instead a stepped tariff is applied (illustrated by the 'orange lines'), the figure shows that it is possible to distribute profits equally among all plants and eliminate high rents to RES-E plants with lower costs.

The main disadvantage of the stepped tariff option is related to increases in the administrative complexity of the FIT and the level of uncertainty to investors, on its application. Table 5 summarises the main pros and cons of the stepped tariff option.

2.2.4.2 Flat tariffs

The main advantage of flat tariffs is that they are administratively simpler to implement and provide more certainty to investors. If the objective was to generate as much electricity at the lowest cost, without encouraging diversity of technologies, then a flat tariff would be the appropriate choice.

In a technology diverse world, flat tariffs are inefficient in that they fail to recognise differences in costs and therefore differences in level of support required – instituting a high flat tariff for example to encourage a high exploitation of wind generation, could lead to some projects achieving high rents (being over-subsided); on the other hand, a low flat tariff may not incentivise the development of projects at sites with less favourable conditions.

Table 5 – Pros and cons of a stepped tariff design in relation to a flat tariff

Pros	**Cons**
Accounts for effect of scale and other factors on plant costs and enable policy to reflect local conditions in tariff level	Potential for high administrative complexity and investor uncertainty
Minimises risk of overcompensating plants and moderates producer profits	Potential for perverse scale incentives leading to greater rewards and therefore higher investments for smaller units or at less productive sites
Enables support for future potential for technologies	Numerous tariff levels may lessen transparency

Source: Fraunhofer ISI, EEG and Pöyry Energy Consulting

Key insights on tariff differentiation from best practices

It is best practice to include banding (i.e. differentiation) in feed-in tariffs. This will certainly be required between technologies to meet the objective of diversity. However to avoid administrative complexity, especially for small scale RES-E generation, it is recommended that banding by scale is limited to situations where the scale economics justify its use and there is a clear potential benefit to supporting smaller scale systems.[16]

2.3 Tariff setting and adjustment mechanisms

The main challenges in setting and maintaining appropriate tariffs in a FIT scheme are:

- it is possible to under or over estimate investors' response to the initial tariff level – this is especially true for a new scheme such as the UK;
- the costs of generation may change from year to year – for example reductions due to innovation, or increases due to increasing cost of components such as higher steel prices. Tariffs therefore need to reflect these changing realities; and
- dealing with the challenge of error in setting tariff levels – what happens when tariffs are set too low (inducing no uptake) or too high (leading to a higher than anticipated new investments but at significantly higher cost).

For the GB FIT scheme, there are several practical questions to consider that tackle these challenges, notably:

- Setting the initial tariffs – what should the methodology be and what levels should the tariff be set at?
- Revision protocol – what should trigger a review of tariffs, and what is the appropriate time period between tariff revisions?
- Degression – should the FIT scheme include well defined degression rates?
- Capacity caps – should the FIT scheme include a self-correcting mechanism in the event that a generously set tariff leads to a larger than anticipated or budgeted for deployment?

2.3.1 Setting the initial tariff

At the start of a new FIT scheme it is necessary to define the levels of the FIT. There are many methodologies for setting the initial feed-in tariff level – the simplest variants involve applying a rate of return, equal to a standard investor hurdle rate, to the specific cost of generating electricity from a typical plant. In this case the plant's specific cost of generating electricity is established based on its relative characteristics to a reference plant, located in the country where the FIT is being introduced. This, for example, is done in Germany and the Czech Republic.[17]

The main disadvantage of using the reference plant methodology, outlined above, is that it can often be administratively complex to define an appropriate reference. On the other hand, the methodology has the advantage of providing transparency and a degree of even-

16 Banding by scale should be considered where there is clear step differences in the technology – for wind for instance turbines come in different defined turbine sizes, any scale differentiation should follow this scale differences rather than an arbitrary scale size.

17 The German scheme aims to provide an 8% rate of return to all technologies.

handedness, since the remunerations to different RES-E plants are based on their individual characteristics against the defined reference, and are easy to verify.

Few schemes reviewed have a transparent or publicly available methodology for calculating or setting new tariffs. However there are several countries that have established formulas for setting tariffs, these include the Czech Republic (see Annex D.1.1.1) and Portugal (see Annex C.1.1.1).

2.3.2 Revision protocol

FIT levels will need to be reviewed and revised to ensure that the tariffs are providing the right incentives required to achieve the FIT policy objectives. Over time electricity generation plant costs will change due to varying input prices (steel etc.), exchange rate movements if a large proportion of the cost is not domestic, and/or technological breakthroughs, this, among other factors, creates the impetus for ongoing revisions. In addition, tariff revisions also allow support to be re-adjusted to correspond with changing policy goals. Sample issues to consider when revising a tariff, include:

- determining the criteria for making policy changes;
- establishing the timeline for making changes in design or reviewing the FIT; and
- establishing grandfathering protocols, if any.

2.3.2.1 Types and examples

Three approaches have been utilised across the EU to revise feed-in tariffs. These are:

- ad hoc reviews (for example, based on the regulator's view of the performance of the FIT) – Spain's unintended revisions prior to 2007 falls in this category;
- periodic reviews of pre-defined periods (for e.g., every 2 or 3 years) – Germany applies this approach and revises its tariffs every three years; and
- tariff reviews on the achievement of specific milestones (for e.g., when a fixed amount of RES-E capacity is added or a set percentage of the long term capacity goal reached) – Portugal applies this approach, wherein the tariffs for the following RES-E technologies are revised when the specified capacity outlined is reach nationwide, PV: 150 MW, Biomass: 150 MW, Biogas: 50 MW. Spain also currently applies this approach, where the tariffs are reviewed once 85% of the Renewable Energy Target has been met for each individual technology. However, as highlighted above, their earlier policies reviews were more of an ad hoc nature.

2.3.2.2 Revision time frames

A policy framework with long periodic revisions will generally lead to higher investment security, and subsequently to higher exploitation of RES-E if the tariff is right, than one with short periodic reviews. On the other hand, longer review periods reduce the flexibility of the FIT system to respond fast enough to changes in technology costs or changes in electricity prices, periodic revisions are therefore anticipated in most feed-in systems. An important balance needs to be struck in relation to flexibility versus investment security.

Following an ad hoc tariff review approach is not advisable as this can result in undesirable booms and bust in RES-E deployment. Recent experience in the Spanish solar PV market exemplifies this danger. In 2005 there were only 37 MW of installed solar PV capacity in Spain, rising from 12 MW in 2000 – currently, there are over 3000 MW of installed solar PV capacity, with around 2670 MW of new installations in 2008 alone. The enormous growth in the Spanish solar PV market was sparked by a very generous feed-in tariff regime[18] for projects registering by September 2008, which led to a much higher than expected level of new installations. September 2008 was a transition deadline established after an ad hoc review resulted in severely reduced remuneration. Since then the market has slowed down markedly.[19]

2.3.3 Capacity caps

One of the consequences of making mistakes in tariff setting by providing overly generous tariffs is that it could induce a greater than anticipated uptake leading to increased scheme costs. The expansion of the PV sector in Spain was in part due to a generous scheme. As a result, some countries, including Spain, apply caps on the volume of new RES-E plants that can be installed in any given year. This can be a very useful feature, as it is often very difficult to predict investors' response to the tariff signals, as it restricts the potential for exploitation booms, which would result in high costs to electricity end users. On the other hand, if the caps are inappropriate set too low, it could affect the effectiveness of the FIT policy. Additionally, a cap that is set too low is likely to be met and will create distortions in the market when this occurs.

As a rule, capacity caps should be avoided unless they are set sufficiently high so as not to artificially constrain uptake. A cap much higher than the required predicted uptake would function as a backstop to keep the market in check and constrain subsidy spend. For example, if the desired or predicted uptake of a given technology was 1.5GW, the cap would be set at 2-2.5GW rather than 1.5GW. There are several other ways caps may be used as a backstop. These include:

- an automatic degression where the tariff declines by a specified amount on achievement of specific deployment milestones – the German EEG for instance includes an automatic reduction of 1% in tariffs if the installed capacity in 2011 reaches 1500 MW; and
- a milestone that automatically triggers a review of the scheme – Royal Decree 661 of the Spanish Scheme states that tariffs will be reviewed once 85% of the Renewable Energy Target has been met for each individual technology. The drawback of a milestone trigger that looks like a cliff edge (and the advantage of a degression cap) is that it introduces investment uncertainty especially if the previous scheme had been unduly generous and there is expectation that any revision may be significantly less generous.

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18 The regime provided returns of 8-12% over 25 years.

19 The capacity cap instituted in September 2008 limits growth in 2009 to 500W, a significant decline from more than 2.5GW installed in 2008 – some industry analysis believe even the 500MW may not be met, see Mark Osborne, Spanish solar installation cap will cause industry contraction in 09, PV-Tech Daily News, March 26, 2009; Fear of Spanish Conditions, Photon International, May 2009 Issue.

2.3.4 Degression

Reduction in the FIT levels over time can be used to provide incentives for technology improvements and cost reductions, and therefore minimises the risk of over-compensating projects. Pre-determined degression rates lead to higher levels of transparency and security for potential investors than reducing the tariff level during a periodical revision. However, rising prices of input factors like steel for wind turbines or silicon for PV devices may lead to an unexpected increase in the price of RES-E plants.

In order to maintain RES-E projects attractive for investors, the price developments of the most important input factors could be taken into account to determine the degression rates. On the other hand, this could lead to increased plant prices, if the plant producers know that the degression rate is variable.

The effect of applying degression in the GB FIT on the costs of small scale RES-E technologies may be limited in the short term since, with the exception of small scale wind generation; the UK is far from being the market leader. However, it is envisioned that the degression of tariffs would have increasing effect in the future as the FIT delivers on the proliferation of small scale RES-E technologies in the UK. Moreover, it is our recommendation that for technologies with global learning rates, the appropriate degression benchmark should be the global technology cost reductions, since UK players would in any case have little impact on cost reductions. However for localised markets, it is advisable to consider feedback from market stakeholders on the appropriate levels of degression. For instance, small scale biomass generators using local pellets are likely to depend on the cost of fuel set by local market conditions, it is therefore advisable to consider the market dynamics and changes in fuel costs in setting their degression rates.

2.3.4.1 Pros and cons of degression

Table 6 highlights the pros and cons of a FIT scheme applying tariff degression.

Table 6 – Pros and cons of a FIT design with degression

Pros	Cons
Investment security – pre-set rates of degression allow investors to factor in most possible tariff changes to their investment decisions	If the degression rate is set for many years, the system is not very flexible, in the case of varying technology prices due to structural changes, e.g. increased prices of steel or silicon
Transparency for investors	It is difficult to set an appropriate degression rate, due to the difficulties in predicting technological learning, which is for example related to the cumulative amount of installed capacity
Incentives for early adopters who gain higher tariffs; and for technological improvements	
Lower burden on electricity consumers	

Source: Fraunhofer ISI and EEG

Key insights on tariff setting, revision protocol, and degression

Germany's approach to review appears to be a good model - revisions are made on a regular three year basis, complemented with well defined degression rates in between which provides a reasonable level of transparency.

The application of degression rates is a more recent phenomenon and more countries are considering whether to implement degression rates in feed-in tariffs. Ideally, the rate of degression is based on the empirically derived progress ratios (technological learning rates) for the different technologies. The assumption being that past learning trends will prevail in the future. Outside of sufficient empirical data to establish precise learning rates, one approach is to gauge the degression based on an estimate of the stage of the particularly technology in its development cycle. For example, hydro-electric technology is mature and hence one would expect a low degression rate compared to say solar PV.

The German FIT experience has shown that well defined technology specific degression rates provide higher levels of investor certainty and transparency than attempts to address plant costs reductions in frequent reviews.

2.4 Other parameter options

There are several other design issues, besides the design parameters discussed above, which affects the characteristic of feed-in tariffs and, consequently, their effectiveness. These are equally important, but are often secondary choices that are in part determined by the choices of the three main parameter decisions discussed above.

2.4.1 Purchase obligation

A purchase obligation is an obligation for electricity grid operators or energy suppliers to buy any power generated by a RES-E plant. For the non-market based schemes (fixed tariffs), it is typically the case that network operators (DNOs) have transactional (purchase) obligations for all the electricity delivered to the grid from RES-E plants. Purchase obligation is very rarely exercised in market based FIT schemes (premium tariff), as this is against the construct of the scheme. The pros and cons of a FIT scheme with purchase obligation, as oppose to one without, are discussed in Section 2.1.

A purchase obligation reduces investor risk, since the revenues for electricity sale are more certain. In countries which offer a choice of premium of fixed tariff, such as Spain, generators who choose the premium tariff do not benefit from such a purchase obligation, and so may be forced to sell power at low prices.

The UK has a liberalised electricity market in which there is no purchase obligation for individual generators. A fixed tariff with purchase obligation would therefore interfere with the UK market operation and impact on the ability of 'traditional' generators to compete. In addition, the current licensing framework for DNOs does not allow them to generate or purchase electricity directly. Consequently, for a purchasing obligation to work either the licensing arrangements for DNOs may have to be amended or alternatively the obligation would need to be placed on suppliers.

The latter approach may make sense in the UK context, as suppliers already have existing relationships with consumers, who are likely to form a significant part of the new group of small scale generators. Suppliers also have the transactional capacity to handle payments and in some cases have experiences dealing with small scale generator-consumers.[20] Finally, given the tight timelines to establish the scheme, amending the licences for DNOs is a less attractive option.

2.4.2 Forecast obligation

A forecast obligation is an obligation on plant operators to predict the amount of electricity they plan to feed into the grid.[21] Market based feed-in tariffs (premium tariff) typically mandate RES-E plants to forecast their future generation output and notify the grid operator in advance – this is to facilitate effective management of the grid. Usually an imbalance charge applies if a RES-E plant output to the grid does not match its forecasted value.

Due to the increased costs of maintaining normal grid operation in the presence of large amounts of renewable generation, some countries now require generators to forecast future generation and notify the grid operator. In Spain, problems caused by large amounts of wind connected to the transmission grid were resolved by establishing a dedicated national control centre for renewable generators. This centre aggregates generation from across the country, and acts as a single point of interaction for the network operator. There is an additional economic benefit, as higher electricity prices can be gained by bidding the generation portfolio as a whole and the quality of the wind generation forecast increases with aggregation.

In the context of the GB FIT, the small size of the plants may make it difficult to apply forecast obligation, as the attendant transaction costs would be high.[22] It may be worth noting however that in Slovenia and Estonia plants as small as 1MW, are required to forecast the amount of electricity they feed into the grid. However, it may be prudent to have forecasting on a regional level as done in Spain in order to minimise the impact of significant small scale RES-E penetration on the management of the UK grid.[23]

On balance, given the additional costs and burden that a forecast obligation carries for a small scale RES plant, it is may be more desirable to socialize the obligation to a larger entity,

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20 Most UK suppliers currently offer buy back tariffs for households. However, there are significant variations in tariffs reviewed, particularly in technology capacity limits (5 – 100kW); eligible technologies (solar and wind predominantly); tariff levels (from 4.50 – 28 per kWh); treatment of ROCs – whether customers retain entitlement to ROCs; and installation and payment for meters – some suppliers install and pay for the cost of the meter, others arrange for installation if required but charge the customer, while others require customers to install and pay for their own.

21 Miguel Mendonca, Accelerating the Deployment of Renewable Energy, World Future Council, 2007.

22 While high transaction costs of forecasting are likely to be a problem for household solar PV and micro-turbines, this does not apply to all technologies at the 5MW scale – a dispatchable plant like 3MW biomass CHP plant is likely to be able to forecast its generation at relatively low cost.

23 National Grid's role, which includes performing the aggregate system load projections, could be expanded to include forecasting aggregate RES-E output.

in this case a supplier who would then be responsible for balancing across all its customers. The added costs to the supplier would in turn be socialized across all users.

2.4.3 Grid connection policies and costs

The distribution of the costs that occur due to new RES-E installations is an important aspect of energy policy. These include:

- cost of connection – all the expenses to physically connect the power plant to the electricity grid;
- cost of extensions or augmentations of the network to the RES-E project; and
- cost of network reinforcements – it is possible that the capacity of the local network is not sufficient to accommodate the new power plant. In this case the electricity network has to be reinforced, which causes additional expenses.

In the EU several connection policies have emerged on how best to distribute the costs that are related to the connection of RES-E plants to the electricity grid.

- in most cases, electricity generators have to pay a *connection charge* to the distribution grid operator that covers a part or the total amount of the costs to connect their plant physically to the grid; and
- in some cases the RES-E producer additionally has to pay a contribution to network reinforcement costs that occur as a consequence of connecting the plant to the grid.

2.4.3.1 Methods of connection charging

There are four methods of connection charging:

- shallow connection charging;
- deep connection charging;
- mixed or shallower connection charging; and
- true connection charging.

Table 7 describes each of the charging methodologies and their advantages and disadvantages.

Table 7 – Pros and Cons of the various connection charging mechanisms

Charging mechanisms	Advantages	Disadvantages
Shallow: RES-E pays for only the cost of equipment needed to connect to grid; upgrade cost borne by grid operator, who usually recovers by applying 'use of system' charges	Minimise connection costs to RES-E. Transparent By applying use of system charges, the grid operator can pass the reinforcement costs to all customers of the electricity network	RES-E developers not incentivised to optimise the location of their plants. (may lead to inefficient choice of plant sites) RES-E generator would have to pay system user fee
Deep: RES-E covers all connection and upgrade costs	RES-E incentivised to chose optimal sites.	High connection and upgrade costs may hinder project development Lack of transparency and difficulty in quantify the true upgrade costs attributed to individual installations.
Mixed: RES-E pays the connection cost and a share of the upgrade cost (share calculated according to estimate of proportional use of new infrastructure)	RES-E incentivised to chose optimal sites.	High connection and upgrade cost may hinder project development May have to pay system user fee
True: RES-E pays cost equivalent to connecting at nearest location that does not require capacity upgrade	RES-E incentivised to chose optimal sites.	Nearest point of connection, which does not require network reinforcement, could be at a significant distance from the RES-E generator and the costs of this connection may be even higher than in the case of the deep charging approach. (ie, it could be more beneficial for RES-E generators to choose a closer connection point and pay for the necessary network reinforcement)

Source: Fraunhofer ISI and EEG

Most EU schemes include a guarantee of a connection to the grid for new generators – typically with shallow connection charges. The direct costs of the connection are typically borne by the project developer, although indirect costs to the network operator such as grid reinforcement are usually socialised.

Grid connection in the UK applies various variants of shallow charging methodology. Connection to the transmission network is on super-shallow basis. FIT-eligible projects (if any) connecting directly to the transmission network incur low connection charges. The transmission system operator (TSO) pays for the system extension and system reinforcement, while the RES-E project pays for the cost of connection. The costs are then socialized to all users via use of system charging – most system cost is recovered from demand customers rather than generators.

The distribution grid connection is operated on a semi-shallow policy. Reinforcement costs are shared between the distribution network operator (DNO) and RES-E project – the costs incurred by the distributor are recovered in part through a distribution use of system charge (DUoS). Under the current system each DNO publishes its own connection charges and DUoS charging methodologies.

The cost of grid connection can be substantial, the equipment costs for connecting to an 11kV Grid range between £20,000 – £60,000 (excluding any costs for works and reinforcements).[24]

2.4.4 Length and term of policy (time frame of support)

The duration of support for given RES-E installations correlates positively with its investment security. In general, a stable, transparent policy framework is crucial for successful and continuous exploitation of RES-E. FITs should therefore be accompanied by long term targets and sufficiently long periods for which the tariff is guaranteed. Short support periods typically require other policy commitment or higher rates to minimise investment risks.

There is no ‘right’ timeframe for support – shorter support periods may be desirable from an investment point of view as investors can quickly recoup their costs. For households and small-scale investors in particular paying the tariffs over a shorter period is desirable, as it enables them to overcome high up front costs of capital and high discount rates. However shorter support periods (between 5-10 years) may require more generous annualised remuneration, and/or other risk mitigation to produce the same level of take-up. This in turn increases the total cost of the scheme. Shorter support periods may also raise the cost of financing for some investors – banks and other loan providers may attach higher risk premiums to shorter support periods since there would be greater economic impact if, for example, a RES-E project were to experience lower than expected availability during the first few years of commissioning.

The benefit of a longer time frame is that it may reduce the real (versus nominal) cost of the scheme and therefore long term cost to consumers.[25] Moreover the experiences of other countries suggest that beyond a certain level of remuneration, the level of support does not

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24 British Wind Energy Association (BWEA), Generating for the UK Electricity System, website accessed April 2008.

25 This depends on whether investors discount at a higher rate than the social discount rate used in the government’s assessment of the subsidy cost (shorter periods could also lower the overall cost of subsidy required to make the investment attractive for certain types of investors). For further discussion see the Quantitive Report on Feed-in Tariffs issued alongside this report (Analysis of a Feed-in Tariff for Sub-5MW Electricity in Great Britain, Quantitative Analysis for DECC). The Quantitative Report contains an analysis of the benefits of reducing tariff lifetimes for different consumers.

necessarily relate to increased take-up – it is therefore more likely that shorter payback periods may not provide the same level of uptake or provide similar take-up at higher cost.[26] A suitable or natural payback period may correspond to the typical term of loans or the lifetime of the technology.

In addition to considerations of the payback period, it may be prudent to consider specific instruments targeted at removing investment barriers or lowering hurdle rates for specific investors such as households. These include:

- Low interest loans and loan guarantees – interest rates and repayment periods of loans have a major impact on the overall cost of RES projects. New technologies, smaller projects or project developers without a proven track record often experience difficulties in obtaining commercial loans at reasonable conditions. Offering low interest loans with lower interest rates and/or longer repayment periods or loan guarantees tailored for specific technologies through subsidies to commercial banks could significantly increase the commercial viability of projects. Low interest loans have been applied successfully in Spain and Germany. The scheme could also provide guarantees for debt repayment to the lending bank, thus reducing risk and hence interest rate (e.g. 1 to 2%), debt term and debt service conditions of the loan. [27]
- Investment subsidies or capital grants paid up-front on the basis of installed capacity or the estimated annual generation of a reference plant – intended to reduce risk and capital cost. Capital grants have been successfully used in the Japanese PV sector. The grants could be targeted at households or other investors with high capital costs rather than open to all investors and could be a lump sum FIT payment or could be structured / tailored depending on technology and/or site and the economics of an average project. The Norwegian scheme for instance provides support based on cash flow analysis for individual projects and implicitly considers technology and site-specific conditions. This helps to give sufficient support while avoiding windfall profits but it limits the economic incentive for increasing efficiency.[28]

2.4.5 Deeming and capitalisation

Deeming involves estimating a RES-E plant's future tariff remuneration stream, while capitalisation involves paying the deemed payments upfront. The approach is not currently applied in the EU except on a small scale in Austria, but it is utilised in Australia to encourage the uptake of small scale generation.

In the Australian scheme, investors of small-scale solar PV, small wind turbines, and micro-hydro systems, are allowed to create at the time of installation, Renewable Energy Certificates (RECs) equivalent to the output of up to 15 years of operation, depending on the system type. This provides an upfront capital subsidy to householders, who are able to sell their RECs on the market.

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26 Deploying Renewables: Principles for Effective Policies, IEA, 2008

27 David de Jager and Max Rathmann, Policy instrument design to reduce financing costs in renewable energy technology projects, IEA -RETD, October 2008 – hereafter Jager and Rathmann, (2008).

28 Jager and Rathmann (2008).

In the context of the UK's feed-in tariff design consideration, this approach could significantly impact on the effectiveness, by overcoming the high discounting typically applied by the householders investor group and other building owners. There are also incentives for other actors in the market, e.g., ESCOs, banks and other financial companies' interested in securitisation.[29]

The Government is currently considering a pay as you save financing mechanism, a variant of deeming and capitalisation (in the heating and energy saving context). Applied to RES-E, a household's contribution to installing a plant would be fully or partially financed by a third party, which would recoup its investments through a standing charge in the energy bills or access to the FIT payments.[30]

While attractive in theory, the deeming and capitalisation approach suffers from the major drawback of reducing the incentives to RES-E plants to generate electricity once they are installed. RES-E investors will have little incentives to keep the plants in operation, since they would have recouped most of their investment costs upfront, and the marginal rates for the plants' output would be low. In addition, where a third party pays up front for the cost of installation, it is unclear what rate of return will be attractive to induce them into the market, or what happens when the house owner moves.

2.4.6 Bonuses for innovative features

FIT schemes may provide additional premiums to RES-E generators to facilitate other policy objectives and where the plant fulfils certain criteria. Examples include incentives for repowering or incorporating demand orientation in the feed-in tariff level. Extra premiums of this sort could help to reach policy goals.

Premiums for additional features like repowering and electricity generation during times of peak demand can be a reasonable measure. On the other hand, most premiums lead to extra administrational complexity. Therefore additional premiums should be used only if the transparency of the system is not affected and if their benefits are higher than the additional administrative costs. Repowering premiums is applied in several countries, including Germany. In general, extra premium should be considered:

- if the electricity generation costs increase due to certain power plant designs, and these designs go along with the policy goals it may make sense to pay an extra premium;
- an extra premium for high plant efficiency, as implemented in France for biogas and geothermal power plants, provides an incentive for plant operators to use the most advanced and efficient technologies, this could help support, for example, the UK government's preferred advanced waste treatment technologies; and

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29 Paying tariffs over a shorter period than the equipment lifetime increases the overall nominal cost of the scheme, if lenders attach higher risk and as a consequence investors demand higher payments. However deeming and capitalisation does not necessarily contradict this conclusion since all deeming does is to shift the risks and costs (if any) or shorter payback to a third party and not to consumers (as a result, it affects the distribution of benefits and risks).

30 Department of Energy and Climate Change (DECC), Heating and Energy Saving Strategy Consultation document, http://hes.decc.gov.uk/consultation/consultation_summary

- extra premiums provide the possibility to influence RES-E producers in their decisions; however it may typically lead to more complexity in a support system. For wind generators in particular it can provide strong incentives for repowering.

2.5 UK specific issues affecting the design of a FIT

Most of the parameters discussed above are generic to all FIT schemes. However, as noted the GB FIT scheme under consideration is likely to be unique for several reasons – unlike almost all other schemes, the GB FIT is limited to small scale generation. The only other scheme with a similar focus is Italy's FIT scheme, which allows sub-1 MW generation to choose between tradable green certificates (the main support instrument) and FIT payments.

There are other unique features of the UK electricity market and regulatory environment that will inevitably shape the final FIT scheme. This includes its interactions with the Renewable Obligation, the UK's principal support scheme, and other climate change policies discussed below; the market design and distribution arrangements. This implies that many of the lessons from other countries may not directly map with the UK situation and would need to be adapted.

2.5.1 Interactions with other incentive schemes, programs

The UK currently has several policies in place to support its carbon reduction commitments (CRC), and is in the process of expanding these measures. It is important that there is coordination among all the carbon reduction initiatives to ensure efficiency and cost effectiveness. As such, it is imperative that the FIT is designed to take into account existing and future carbon reduction policy measures.

2.5.1.1 Renewables Obligation

Renewable electricity generation in the UK is currently supported by the Renewables Obligation scheme. The RO places a legal obligation on licensed suppliers to purchase a specified proportion of the electricity they supply from eligible renewable generation.[31]

There are no restrictions on scale of RES-E projects eligible for the RO, although the level of support currently differs by technology as shown in Table 8 below. The current differentiation by technology came to effect on 1 April 2009.[32] The obligation will remain on suppliers until 31 March 2027, although a possible extension to this end-date may result from the on-going UK Renewable Energy Strategy.[33]

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31 Suppliers to consumers located in Great Britain were initially set an obligation to purchase 3% of their supplies from qualifying and accredited renewable generators during the period 1 April 2002 to 31 March 2003, rising to 9.1% in 2008/9, 10.4% in 2010/11 and to 15.4% in 2015/16. Suppliers to consumers in Northern Ireland have been set a lower obligation level of 2.5% in 2005/6, rising to 6.3% in 2012/13.

32 Statutory Consultation on the Renewables Obligation Order 2009, BERR, 26 June 2008.

33 Current revisions envisaged may include extending the current end-date of the RO from 2027 to 2035 or beyond; and increasing or removing the current cap of 20% on the level of the obligation.

There is scope for inefficient interactions between the FIT scheme and the RO, especially for larger projects (for instance >500 kW) which would be eligible for both and are not as constrained by transaction costs of participating in either schemes. It is therefore advisable for technologies currently successfully supported by the RO, to taper feed-in tariffs so that the level of support approach or are slightly below the RO values as the RES-E installation size get larger, with convergence at the 5 MW threshold.[34]

Table 8 – Support by technology for the first phase (2010 – 2013) of a banded RO

Technologies	MWh/ROC	ROCs/MWh
Landfill gas	4	0.25
Sewage gas and the co-firing of non-energy crop (regular) biomass	2	0.5
Onshore wind, hydro-electric, co-firing of energy crops, co-firing of biomass with CHP, EfW with combined heat and power: only the qualifying output[35] derived from the non-fossil element of waste, geopressure and other not specified	1	1
Offshore wind, dedicated regular biomass and co-firing of energy crops with CHP	2/3	1.5[36]
Advanced conversion technologies (anaerobic digestion[37]; gasification[38] and pyrolysis[39]): only the energy derived from the non-fossil element of waste, dedicated biomass burning energy crops (with or without CHP), dedicated regular biomass with CHP, solar photovoltaic, geothermal, wave and tidal stream, tidal impoundment: tidal lagoons and barrages (<1GW) and microgeneration	0.5	2

Source: Statutory Consultation on the ROO 2009, BERR, 26 June 2008

34 For technologies that are currently not successfully supported by the RO, such as large scale solar PV installations – and where the support required is still substantially higher than the support offered under the RO, this is less of a concern. However, the interaction with the RO is still important to get right in so far as there is a competition for investment funding (overcompensating them in disregard to the RO, may very well see investment flowing to these technologies rather than others covered by the RO).

35 Qualifying renewable output will be calculated as the non-fossil fuel generated electrical output of the generating station, multiplied by the ratio of the 'Good Quality' CHP output to total power output. The qualifying combined heat and power station and the total power output are defined by CHPQA.

36 There is a short window of 2 ROCs per MWh currently in place.

37 The bacterial fermentation of organic material in the absence of free oxygen.

38 Producing gaseous fuels by reacting hot carbonaceous materials with air, steam or oxygen.

39 The heating of the organic fraction of wastes in the absence of air to create char and either gas or liquid.

There are other secondary implications concerning the interaction between the FIT and the RO to consider, this includes:

- For current projects, the scheme will need to affirm whether and when to allow plants meeting the 5MW threshold currently accredited to the RO to opt into the FIT scheme – it is advisable to move microgen schemes accredited to the RO to the FIT. Opting them into the FIT will allow the RO to concentrate on large renewables. It will also save on the cost of administering the RO (at present, 50% of OFGEM's costs of administering the RO are incurred due to small scale generation who receive less than 0.1% of the payout). However, because the cost of the RO to consumers is set by RO targets and the buy out price, independent of the amount of renewable electricity generated, moving projects from the RO could result in higher costs to consumers since it will only result in projects staying within the RO receiving more money, and similarly projects moving to the FIT being compensated with new funding and presumably at a higher rate.[40] The secondary decision is when to join the FIT – some stakeholders have recommended a delay of at least two years to allow reasonable forecasting of the size of the FIT pot.[41]
- For future microgen projects, the regulatory regime will need to clarify whether they should be allowed to choose between the RO and the FIT or be defaulted to the FIT scheme without an opt-in to the RO. Since ROC prices depend in part on number of projects allowing many small schemes to opt-in will not only increase the cost of administration, but would also make supply of ROCs and resulting prices harder to forecast. For larger schemes which could have a choice between the FIT and the RO, there is a secondary decision on how long to allow them to make a choice – whether on an annual basis or a once-off basis.

2.5.1.2 Renewables Heat Incentive (RHI) scheme

The Department of Energy and Climate Change (DECC) is currently working on setting up a Renewable Heat Incentive (RHI) scheme to encourage the development of the renewable heat energy sector. According to estimates published in June 2008, heat generated from renewable sources currently accounts for only 0.6% of total heat demand and may need to rise to 14% to meet binding EU targets on renewable energy.[42]

While details of the RHI scheme have not yet been finalised, there is again the potential for inefficient interactions with the FIT scheme, which will have to be properly managed. Remuneration under the RHI will most likely be applicable under both the FIT and RHI schemes for biomass fuelled CHP/ cogeneration plants. Possible impact on the FIT includes reduction in the market for micro-CHP if, for example, the RHI is very generous. One approach to deal with this issue may be to remove biomass CHP completely from the FIT scheme and allow the RHI to address this solely. However, for a feed-in tariff that provides equal support to all biomass CHP technologies, additional support under the RHI would

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40 Jose Davila, How to attain harmony between FIT & RO, British Gas New Energy, 26 March 2009

41 See REA and stakeholder working groups, Renewable Electricity and Heat Tariffs – Preliminary recommendations on their implementation from the renewable energy industry, March 2009

42 See DECC/DBERR on Renewable Heat Incentive (RHI) http://www.berr.gov.uk/energy/sources/renewables/policy/renewableheatincentive/page50364.html

encourage installations to utilise waste heat (either on-site or through district heating networks) rather than operate electricity-only plants.

2.5.1.3 CERT / Supplier Obligation

The Carbon Emissions Reduction Target (CERT) is an obligation on energy suppliers to achieve carbon targets by encouraging households to take up energy efficiency and low carbon measures.[43] The CERT is the principal scheme for improving household energy efficiency and carbon reduction.

Since suppliers can claim the Carbon Emissions Reduction Target (CERT) credit for microgen, as the FIT increase their deployment, there is a danger of swamping the CERT scheme. One possible solution will be to remove FIT supported technologies from CERT. However, CERT could be a way of providing additional support to the smaller domestic type installations on top of a flat FIT.

2.5.1.4 Zero Carbon Homes

The UK has instituted legislation requiring all new homes built from 2016 to be zero-carbon, and has provided incentives in the way of stamp duty exemption to buyers of new zero-carbon house, under a scheme introduced in 2006.

The Government's current definition of zero-carbon home excludes the use of offsite renewables unless it is connected by a private wire to the development. This effectively limits the RES-E generation to onsite microgeneration renewable technologies, and should therefore reduce the potential for interaction with the FIT scheme. However, this situation may change, as the Government has committed to reviewing its definition of zero-carbon home, in light of pressure from the construction industry to include buildings that use energy generated at local larger-scale plants in the qualification of zero-carbon.

2.5.1.5 Code for sustainable homes

The Code for Sustainable Homes (CSH) came into effect for new homes from 1 May 2008. The CSH measures the sustainability of a new home against categories of sustainable design, rating the 'whole home' as a complete package.[44]

Both CSH and ZCH will need a policy decision on whether the RES-E measures installed under CSH and ZCH will be eligible for the FIT. If so, CSH and ZCH will be much easier to

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43 DECC, Household energy supplier obligations –The first two phases ran from 2002 to 2005 and 2005 to 2008 while the third phase is expected to run from April 2008 -March 2011. Suppliers have full leeway on how to meet the targets, although common measures have included subsidised offers on loft and cavity wall insulation, and provision of high-efficiency lighting, heating systems, appliances and energy saving devices.

44 Department of Communities and Local Government – Code for Sustainable Homes, the Code uses a 1 to 6 star rating system to assess the overall sustainability performance of a new home. The Code sets minimum standards for energy and water use at each level and, within England, replaces the EcoHomes scheme, developed by the Building Research Establishment (BRE).

meet, as the value of the FIT can be set against the capital expenditure of the on-site measures needed for compliance.[45]

2.5.1.6 Waste policy

There is prospect of achieving synergy between the FIT and waste policies. The FIT represents an added bonus on top of the existing waste policy – waste diverted from landfills can be used for energy production in many small scale biomass plants instead of in large scale incinerators, which often meet severe opposition to get approval. However, an abundant availability of cheap biomass in the form of waste could also reduce the support required from the feed-in tariff to achieve the same level of exploitation. The financial viability of many waste schemes is reliant on gate fees from waste feedstocks as much as revenues for electricity sales. Widespread deployment of waste technologies encouraged by the Feed-in Tariff could increase competition for waste and reduce revenues for new and existing plants. This would necessitate higher tariffs to provide investors with sufficient rates of return.

2.5.2 Administration of the scheme

2.5.2.1 Payments and administration

There are several options for administering a FIT scheme. The most common option involves the local distribution network operator (DNO) acting as an administrator for the scheme (as highlighted in Option B in Figure 4).

Under this option, the generator signs a contract with the DNO which sets out the rules for the payments. The DNO pays the generator for any electricity generated and recoups the payments from electricity customers through suppliers. In countries with regional disparities in renewable energy resource, there is an additional national reconciliation. In Germany for instance the Renewable Energy Sources Act (EEG) 2009 sets out how funds should be distributed between the various grid operators across the country. This allows utilities in the North (with high FIT payments for the large wind deployments there) to recoup funds from those in the south with more limited RES penetration.

There are three main variants of this option[46]:

- The para-fiscal levy system practiced in most EU states – under this variant, the TSO and the DSO are obligated to purchase any generation from a RES-E plant at the specified feed in tariff and are subsequently compensated through a consumption-based levy collected from energy users.
- The Preussen Elektra system used predominantly in Germany[47] – in this variant, the DSO is obligated to purchase any generation from a RES-E plant at the specified feed in

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45 When viewed in isolation, making a plant installed under ZCH/CSH eligible for the FIT increases the cost of the subsidy with no additional electricity generation, since the developers are already obliged to install the plant. It may alter the relative economics of technology solutions that can be used to meet the legislation e.g. solar PV vs. wind vs. site-wide CHP

46 John Bruton, The EU's experience in the use of economic instruments, including taxation, to reach specific objectives in energy policy, Statement to the Committee on Finance, United States Senate, March 29, 2007

tariff under a burden sharing arrangement with the TSO. The grid operators are allowed to pass the additional financial burden to users through higher electricity prices – user fee increments however have traditionally required the prior approval of the ministry of the economy of the German Länder (state) in question.

- The connection fee system practiced in Austria, Ireland, the Netherlands and Slovenia – in this system, users pay a lump sum payment on connection, irrespective of the amount and source of the electricity consumed that is used to support the scheme. The grid operator who is often responsible for the scheme or a third party may take into account such factors as the power of the connection (fuse rating) and the voltage level at which particular consumer and consumer group is connected in calculating the lump sum.

Further variations of the DNO / DSO administration system may depend on the structure of the electricity market – in a few jurisdictions the DNO is also often the supplier. Each grid operator / supplier utility directly recoups payments to generators from its customer base, with a regional or national reconciliation to account for variations in level of RES-E penetration.

In the UK, the licensing framework for DNOs does not allow them to perform this function without license modifications. The more likely option therefore would be Option A - outlined in Figure 4 which involves suppliers being responsible for contracting with generators, and making payments for electricity supplied, and a separate administrator responsible for reconciliations. Under Option A, a household or small scale generator would sign a contract with their local supplier, and install an applicable metering device to record separately the gross amount generated and amount consumed by the household.

In general, given the perception of high transaction costs (compared to actual costs) that households in particular are likely to have, keep the administration of the scheme easy to understand and transparent and relatively unencumbered by any bureaucratic measures

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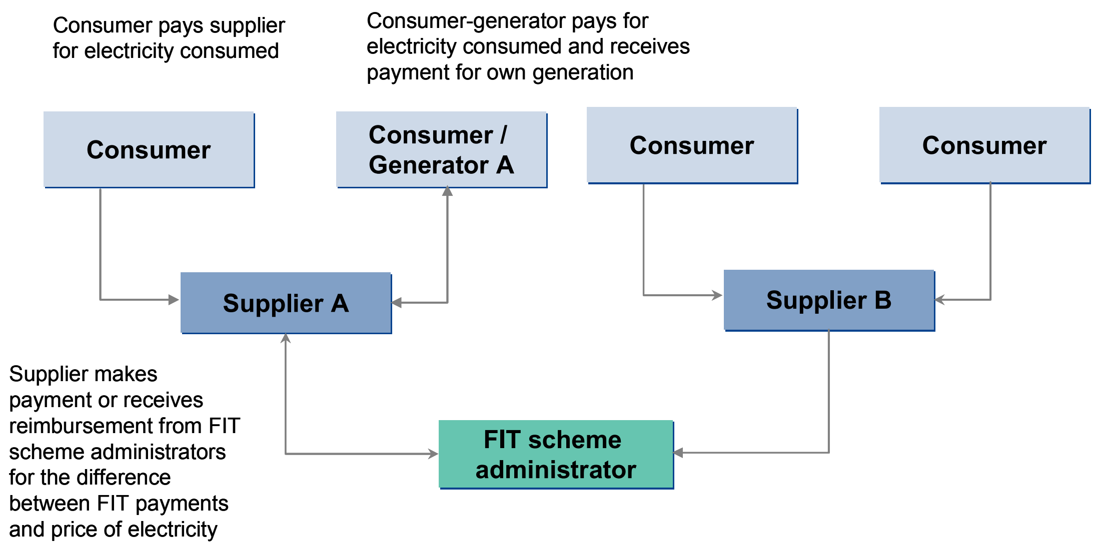
[47] Named after PreussenElektra AG v Schhleswag AG [2001] EUECJ C-379/98 – the first European Court of Justice case which considered the implications of state aid rules in the design of FIT schemes.

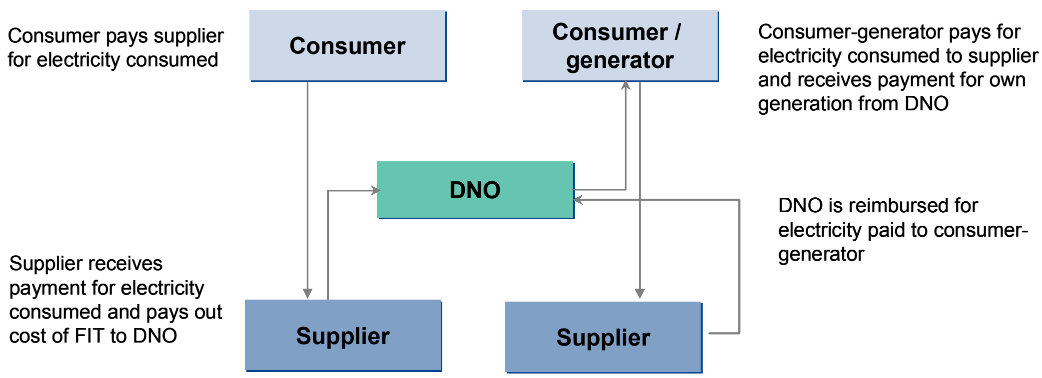
Figure 4 – Options for administration of FIT scheme

Option A



Source: Pöyry Energy Analysis

Option B



Source: Pöyry Energy Analysis

2.5.2.2 Definition of installations for the purpose of payments

The GB scheme as currently envisaged limits participation to renewable installations with a capacity of 5MW or less (for the defined technologies). The legal text will invariably define which installations are eligible or not, however the main issues would likely include:

- Defining installations to ensure that a site meets the maximum capacity requirement of a given FIT payment band – this involves for example ensuring that a wind farm is below

5MW and not two 4MW farms adding up to an overall 8MW system. Similar concerns might apply to ensuring a PV system is below 10 kW if there is a Fit band below this level. In part this involves structuring remuneration such that there is less incentive to creatively fit a project in one band as opposed to the next, but also clearly defining which incentives are eligible for a particular scale and leaving little room for ambiguity.[48] The regulatory regime will also need to define how to deal with changes to installations – whether additions to a 5MW plant (automatically renders a plant ineligible) or downsizing of a 6MW plant makes it eligible and whether the incentives are appropriately structured to prevent inefficient changes meant to increase plant revenues.

- The scheme will also need to provide an appropriate treatment of those installations deployed before the scheme comes in force and whether they would be eligible. The case for retroactively supporting installations deployed before the scheme comes into effect is that doing so may not be too costly (given the current installed base of microgeneration plants) but would send the right signals to investors of the government's commitment. An announcement of retroactivity may also allow currently scheduled developments to go ahead as planned without delaying until after the scheme is launched. The case against retroactive support is that current projects are already supported (through grants schemes such as the Major PV Demonstration Programme and the Low Carbon Buildings Programme), or are already independently economically viable – therefore excluding them avoids incremental costs to the scheme in supporting viable projects.
- Finally, the regulatory regime will need to be explicit about the treatment of changes to the scheme in later years and how they impact installations – whether grandfathering of existing support which is recommended is guaranteed.

2.5.2.3 Metering

There are two types of metering arrangements. Gross metering involves paying a consumer generator for all electricity generated, and separately charging for all electricity consumed. Net metering arrangements involve the consumer-generator getting paid for supply exported to the grid (the difference between what is generated and consumed).

Most feed-in tariff schemes operate on a gross metering system requiring a separate individual meter to register the electricity generation from the RES-E plants. As part of the metering arrangements, the owner of an RES plant would be paid a tariff for the gross amount generated, not just the net amount exported to the local network. The household or business would continue to pay the normal, prevailing price for the electricity they consume.

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48 In the German FIT scheme (EEG) legislation, several installations are classified as one installation, notwithstanding ownership, and solely for the purpose of determining the tariff to be paid for the latest generator commissioned where (a) they are located on the same plot of land or are otherwise in direct spatial proximity; (b) they generate electricity from the same kind of renewable energy source; (c) the electricity generated in them is paid for in accordance with the provisions of the Act depending on the capacity of the installation, and (d) they were commissioned within a period of twelve consecutive calendar months. Such a definition in the GB context would foreclose two 4MW sited next to each other from claiming to be two separate installations.

The two amounts – the tariffs received for generating and the tariffs paid for electricity consumed would then be netted off.

The advantage of gross metering is that it rewards the benefits of embedded generation that accrue to the system irrespective of whether electricity is exported or not. These include lower transmission losses, deferred costs for network augmentation, and displacement of high-cost generation during peak periods. Most household systems are unlikely to have a net export balance, and would therefore not gain from net metering systems despite providing these benefits.[49]

The cost of the metering system (inverters and meters) can be sizeable for households and very small scale installations of the order of 50 kW.[50] As discussed earlier, deeming and capitalisation is one approach to address the upfront capex – this may be advantageous in meeting the metering costs for very small scale installations.

2.5.2.4 State aid implications

There is a potential for feed-in tariffs to be viewed as a state aid, when they take the form of tax – this is especially important when the administrator of the scheme is state owned. In 2005, the European Commission investigated the Slovenian FIT scheme's system of preferential dispatching of electricity aimed at boosting renewable energy, for possible violation of EU state aid rules.[51] The case led to a redefinition of the way in which the costs of the scheme was distributed – from a (kWh) electricity generation basis to a capacity (kW) of installation basis, which is less desirable.

This highlights the fact that the potential for being classified as a state aid can affect feed-in tariffs policy outcome, which means that Government needs to be careful about how it defines the administration and operation of the scheme.

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49 According to the Standard Assessment Procedure (SAP), the government approved method for assessing the energy performance of domestic property, domestic PV systems for instance, are assumed to export 50% of their output to the grid due to mismatches between generation and on-site demand over the day, however on a net basis, the net export is likely to be small if any, for most plants given the higher domestic or commercial consumption.

50 An OFGEM approved gross generation meter that measures all the output a system retails for about £75 plus VAT, however a grid-tie inverter generally retails from £500-2,000 depending on voltage

51 Under the scheme in question, Slovenian network operators were obligated to purchase electricity produced from renewable energy sources and efficient combined heat and power plants at a price above the market price fixed by the State. The aid thus provided did not exceed the difference between the market price and the production cost and was therefore in line with EU regulations. However, as part of the scheme, consumers had to pay an additional parafiscal levy on their electricity consumption. According to the Commission this could have led to discrimination against imported green electricity. The re-design was to finance the scheme through a lump sum based on connection power. See European Commission Press Release, State aid: Commission endorses support for green electricity and for security of electricity supply in Slovenia, April 25, 2007

2.5.2.5 Inflation and exchange rate

For RES-E plant operators, most of the capex spend is for equipment priced in Euros or US dollars. Given the volatility in exchange rates witnessed over the past year, this poses significant risk especially if the equipment purchase is co-financed by the vendor or a third party on a long-term repayment option.

The treatment of inflation in FIT design has also taken on tremendous importance to investors in recent times, given the current economic climate. Investor certainty can be improved by including inflation and exchange rates in the FIT – both factors influence the power generation costs of RES-E plants and should be taken into consideration when the initial tariff levels are being determined, and in subsequent revisions.

2.6 Conclusion

All FIT schemes as highlighted in this section are permutations of three major design parameter choices: the choice of fixed tariff or premium tariff; choice of stepped tariff or flat tariff; and choice of tariff setting and adjustment mechanisms. In addition to these major choices there are other decisions that are important, such as an appropriate length and term of policy (time frame of support); whether to impose a capacity cap or not, purchase and forecast obligation for RES-E plants, whether to provide additional bonuses for innovative features and the appropriate grid connection and charging policies.

2.6.1 Key insights from review of design options

2.6.1.1 Choice of fixed vs. premium tariffs

Our analysis of the pros and cons of fixed and premium tariffs highlights that for a FIT geared to increase up take of small scale renewable electricity projects, the fixed tariff option is likely superior for non-controllable RES-E generation. This is because the extra transaction costs for implementing a premium tariff and the additional risks and uncertainty may outweigh the grid management benefits to be realised from a premium system. However the transaction costs of participating in the market are usually small for larger controllable RES-E generation – their outputs can easily be predicted, which minimises their associated balancing and demand management costs. The premium option should be explored for larger controllable RES-E generation, since it provides the right market signals for the RES-E plants at the expense of only a minimal transaction costs to participate in the market.

2.6.1.2 Choice of stepped vs. flat tariff

A review of the advantages and disadvantages of tariff differentiation confirms DECC's inclination to include banding in feed-in tariffs – certainly between technologies. However to avoid administrative complexity, especially for small scale RES-E generation, it is strongly recommended that banding by scale is limited to situations where the scale economics justify its use and there is a clear potential benefit to supporting smaller scale systems.

2.6.1.3 Setting and revision of tariffs – protocols and application of degression

In setting and revising tariffs, an indicative recommendation is that revisions should be made on a regular basis – such as a three year basis, complemented with well defined degression rates in between which provides a reasonable level of transparency.

The application of degression rates is recommended and should be based on the empirically derived progress ratios (technological learning rates) for the different technologies. The assumption being that past learning trends will prevail in the future. Outside of sufficient empirical data to establish precise learning rates, one approach is to gauge the degression based on an estimate of the stage of the particularly technology in its development cycle. For example, hydro-electric technology is mature and hence one would expect a low degression rate compared to say solar PV.

As noted, the German FIT experience has shown that well defined technology specific degression rates provide higher levels of investor certainty and transparency than attempts to address plant costs reductions in frequent reviews.

2.6.2 Impact of UK experiences

The recommendations made above are generic and do not take into account the specific conditions to the UK. In particular the relationship with the Renewable Obligation scheme which remains the UK's flagship support mechanism, and interactions with other energy and climate change regulations and schemes as well as the UK's electricity market arrangements.

2.6.2.1 Interactions with the RO scheme and other climate change policies

The UK currently has several policies in place to support its carbon reduction commitments (CRC), and is in the process of expanding these measures. The design of the FIT scheme will need to accommodate these existing regulatory framework and initiatives to ensure efficiency and cost effectiveness. The FIT for instance should be tapered so that the support levels provided approach the RO values as the RES-E installation size get larger, with convergence at the 5 MW threshold. Other schemes that similarly impact the extent and level of support include the Renewables Heat Incentive (RHI) scheme, the CERT / Supplier Obligation, the Code for sustainable homes, the Zero Carbon Homes and the Waste policy.

2.6.2.2 Administration of the scheme

The most common option for administering the FIT in Europe involves the local grid or distribution network operator acting as the focal point of the scheme, paying the generator for supply and collecting payments from suppliers. Under this option, the utility signs a contract with the generator which sets out the rules for the payments. The utility must then recoup the payments from electricity customers. However the incumbent UK market arrangements are likely to influence the eventual design of the scheme –the GB scheme is more likely to involve suppliers being responsible for payments for electricity supplied by generators, and a separate administrator responsible for reconciliations.

In such an arrangement, the household or small scale generator would sign a contract with their local supplier, and install an applicable metering device to record separately the gross amount generated and amount consumed by the household. The reasons for this, is that the DNOs have neither the capacity to handle the likely volumes of transactions, nor do their licensing arrangements allow for their purchase of electricity. Short of an amendment, which may become a lengthy process, the supplier route seems a viable option. This is one of the many ways the experiences of other countries may not directly apply to the GB scheme.

3. LESSONS FROM SELECTED NATIONAL EXPERIENCES

This section progresses the discussion in Section 2 in two ways – it presents:

- A detailed assessment of selected FIT schemes. Starting from all 19 EU FIT schemes currently in operation, we group them according to the major parameter choices identified in Section 2, to find out common features as a means to understanding why certain options are preferred to others. Secondly, we select several schemes that are identified as broadly representative of the main design options, and compare their design features. Finally, we develop a simple comparative methodology to assess the performance of the selected schemes not only on policy objectives, but also on administrative ease of implementation, with a view to identifying additional lessons for the GB scheme.
- A summary of selected findings from literature review, specifically several large scale studies on parameter choices, with a view to illuminating best practices and recommendations for the UK.

3.1 Grouping of FIT Schemes according to key design parameters

As noted in Section 1, 70% of EU-27 countries use FIT schemes as their main renewable energy incentive scheme. Despite an array of differences, the schemes can be broadly grouped according to the key design parameters identified in Section 2.

Figure 5 below provides our indicative grouping of European FIT schemes. In general, when viewed in the three dimensional context of fixed vs. premium; flat vs. stepped and degression vs. no degression, all FIT schemes fall into these six categories. In addition, we find that:

- in the choice between fixed and premium tariffs, most schemes use fixed schemes. Of all the 50 distinct sets of choices offered in Europe, 78% offer fixed tariffs;
- majority of schemes are both stepped or banded and with technology differentiation – 39% of all options available provide both technology, scale and /or other differentiation in tariffs. Even among the schemes with flat tariffs (that do not offer scale or other differentiation, technology differentiation is also predominant);
- degression is not presently common, although several states are reviewing incorporating degression in future reviews; and
- a significant number of countries apply different design options for different RES-E technologies, and therefore appear in more than one group – in most of such cases, one technology is treated differently from the rest.

Figure 5 – Group of FIT schemes in the EU according to key design parameters

WITHOUT DEGRESSION				
FIXED	**Cyprus** (H, SB, B) **Denmark** (SB, B) **Estonia** (H, wind, SB, B, PV, G) **Hungary** (H, ONW, SB, B, PV, G) **Ireland** (H, SB) **Italy** (H, ONW) **Lithuania** (H, SB, B - ONW, OFW)	**Austria** (H, SB, B, PV) **Bulgaria** (H, ONW, SB, B, PV) **Cyprus** (PV) **Czech Rep** (H, ONW, SB, B, PV) **Denmark** (PV) **France** (H, SB, B, PV, G) **Greece** (PV) **Ireland** (ONW, OFW, B) **Italy** (SB, B) **Latvia** (H, ONW, SB, B) **Luxembourg** (PV) **Portugal** (H, ONW, SB, B, PV) **Slovakia** (H, ONW, SB, Bs) **Slovenia** (H, ONW, SB, B, PV) **Spain** (SB, B, PV)	**Austria** (ONW, G) **Cyprus** (ONW, OFW) **Czech Rep** (G) **Denmark** (G) **Greece** (OFW) **Italy** (G) **Portugal** (OFW) **Slovenia** (G) **Slovakia** (PV, G) **Spain** (H, ONW, G)	**Greece** (H, ONW, SB, B, G) **Luxembourg** (H, ONW - SB, B)
PREMIUM	**Estonia** (H, wind, SB, B, PV, G) **Netherlands** (H, OFW, PV)	**Czech Rep** (H, ONW, SB, B, PV) **Netherlands** (SB, B) **Slovenia** (H, ONW, SB, B, PV) **Spain** (H, ONW, OFW, SB)	**Czech Rep** (G) **Denmark** (ONW) **Netherlands** (ONW) **Slovenia** (G) **Spain** (B, G)	
	FLAT	TECHNOLOGY AND SCALE DIFFERENTIATION	TECHNOLOGY DIFFERENTIATION ONLY	SCALE DIFFERENTIATION ONLY
		STEPPED		

WITH DEGRESSION				
FIXED		**Germany** (H, OFW, SB, B, PV, G) **Italy** (PV)	**France** (ONW, OFW) **Germany** (ONW)	
PREMIUM				
	FLAT	TECHNOLOGY AND SCALE DIFFERENTIATION	TECHNOLOGY DIFFERENTIATION ONLY	SCALE DIFFERENTIATION ONLY
		STEPPED		

Key: H – hydro, SB – solid biomass, ONW – onshore wind, B – biogas, PV – solar, OFW – offshore wind

Source: Pöyry Energy analysis based on Fraunhofer ISI and EEG information and individual state schemes

3.2 Selection and comparisons of case study schemes

3.2.1 Identifying main groups and selection of case studies

As highlighted in Figure 5 we have identified six main groups from the grouping of EU countries applying feed-in tariffs. From these six main groups, we have chosen six countries as case studies, which are broadly representative of most of the possible design options. The countries chosen are Germany, Spain, Portugal, the Netherlands, the Czech Republic, and Denmark.

Table 9 below outlines the key FIT design attributes of the main groups and of the respective selected countries in each group:

- All six countries selected, provide technology differentiated tariffs – a confirmation that this is regarded as best practice.
- Some of countries, e.g., Spain and the Czech Republic, apply both fixed and premium tariffs – In Spain's case the choice must be made for at least a one-year term and communicated at least one month in advance to the responsible authority (the choice is not open for solar PV plants). In practice in recent years, as electricity prices have risen almost all wind plants in Spain have opted for the premium option. In the Czech Republic, largely due to transaction costs, most plants have opted for the fixed option.
- Formal application of degression is still rare – with only the German scheme implementing it so far, however, it is worth noting that several countries, including Spain, have recently enacted policies to include degression in future FIT implementation.

Table 9 – Key FIT design attributes of main groups and selected countries

Number of countries in group	Key attributes of group	Country selected
15	Non-degression, fixed tariff, stepped with technology and scale differentiation	Czech Rep (H, ONW, SB, B, PV) Portugal (H, ONW, SB, B, PV) Spain (SB, B, PV)
10	Non-degression, fixed tariff, stepped with technology differentiation	Spain (H, ONW, G)
7	Non-degression, fixed tariff, flat	Denmark (SB, B)
5	Non-degression, premium tariff, stepped with technology differentiation	Czech Rep (G) Denmark (ONW) Netherlands (ONW) Spain (B, G)
4	Non-degression, premium tariff, stepped with technology and scale differentiation	Czech Rep (H, ONW, SB, B, PV) Netherlands (SB, B) Spain (H, ONW, OFW, SB)
3	Degression, fixed tariff, stepped	Germany (H, OFW, SB, B, PV, G, ONW)

- **Six distinct countries identified for case studies**

Key: H – hydro, SB – solid biomass, ONW – onshore wind, B – biogas, PV – solar, OFW – offshore wind

Source: Fraunhofer ISI and EEG

3.2.2 Key characteristics of selected FIT schemes

Table 10 highlights the key characteristics of the selected FIT schemes in terms of their subsidiary design parameters discussed in the Section 2 of the report:

- stepped tariffs are nearly universally applied in the selected schemes;
- purchase obligation on electricity supplier or the grid operator is universally applied;
- forecast obligation is less common – within the group only Spain applies it (and the Netherlands for specific scales); and
- burden sharing of the costs of implementing the scheme is also common across all schemes – Denmark and Germany apply an equal burden sharing, based on a per unit of electricity charge but provide relief for electricity intensive industries. Portugal, Spain and the Czech Republic do not provide any relief, while consumers in the Netherlands contribute the same amount of money to RES support, regardless of the amount of electricity consumed.

Table 10 – Selected design issues for selected countries

Country	Purchase obligation	Stepped tariff	Tariff degression	Premium option	Equal burden sharing	Forecast obligation
Czech Republic	✔ (for fixed tariff)	✔	-	✔	✔	-
Denmark	✔ (except for onshore wind)	✔	-	✔ (for wind)	✔ a)	-
Germany	✔	✔	✔	-	✔ (a)	-
Netherlands	-	✔	-	✔	b)	-
Portugal	✔	✔	-	-	✔	-
Spain	✔ (for fixed tariff)	✔	-	✔	✔	✔

Source: Fraunhofer ISI and EEG

3.2.3 Tariff level and support duration of selected schemes

The selected schemes exhibit diversity in the level of support provided. Table 11 below summarises the tariff levels and policy support duration available for RES-E projects installed in 2008 under the selected FIT schemes. The figures provided for the premium schemes represents the premium that is paid on top of the market price and not the overall remuneration. In general, we find that:

- support is generally guaranteed in the fixed tariff options for a period of 15 years as an estimated average across all schemes. Germany applies the longest policy support framework of all the FIT schemes – with support guaranteed for 20 years;
- the average remuneration is broadly uniform across all countries for the mature technologies such as on-shore wind, hydro and biomass generation, with a maximum variance from the mean of 1.4 cents for small hydro tariffs and onshore wind.
  - Czech Republic offers the most generous average tariffs for hydro, onshore wind, solar PV and geothermal; and
  - Germany offers the most generous upper bound tariff for small hydro and off-shore wind, solid biomass, biogas and geothermal.

Table 11 – FIT level and support duration for selected countries

Tariff level in 2008 [€ Cents/kWh] and duration of support for different technologies

Country		Small hydro	Wind onshore	Wind offshore	Solid biomass	Biogas	PV	Geothermal
Czech Republic	Fixed	10.40 15 yrs.	9.84 15 yrs.	–	10.08 – 16.84 15 yrs.	13.2 – 15.6 15 yrs.	53.84 15 yrs.	17.2 15 yrs.
	Premium	5.60 15 yrs.	7.48 15 yrs.	–	4.96 – 11.72 15 yrs.	8.08 – 10.48 15 yrs.	50.60 15 yrs.	12.9 15 yrs.
Denmark	Fixed	–	–	–	8.0 10 yrs.	8.0 10 yrs.	20.0 – 25.0 20 yrs.	6.9 20 yrs.
Germany[1]	Fixed	7.65 – 12.67 20 yrs.	9.2 20 yrs.	13.0 - 15.0 20 yrs.	7.79 – 22.67 [2] 20 yrs.	7.79 – 29.67 [2] 20 yrs.	31.94 – 43.01 20 yrs.	10.5 – 20.0 20 yrs.
Netherlands	Fixed	–	–	–	14.7 10 yrs.	–	–	–
Portugal	Fixed	7.5 – 7.7 15 yrs.	7.4 – 7.5 15 yrs.	7.4 15 yrs.	10.2 – 10.9 15 yrs.	11.5 – 11.7 15 yrs.	31 – 47 15 yrs.	–
Spain	Fixed	7.8 25 yrs.	7.3 20 yrs.	–	14.6 – 15.9 15 yrs.	8.0 – 10.8 15 yrs.	23.0 – 44.0 25 yrs.	6.9 20 yrs.
	Premium	2.1 – 2.5 no limit.	2.9 no limit	14.1 – 16.4 no limit	10.0 – 11.5 no limit	9.4 no limit	–	3.8 no limit

1) For installations commissioned 2009 according to the new EEG from June 2008

2) Maximum value is only available if all premiums are cummulated (premiums for innovation technologies, CHP, sustainable biomass etc.)

Source: Fraunhofer ISI and EEG

We have reviewed the overall remuneration that a RES-E plant developed and commissioned in 2008 would have received for each of the countries that we have selected. The premium remuneration is based on the average annual wholesale price of electricity in each market and the premium.[52] The results are summarised in Table 12: In particular it highlights that:

52 Annual average wholesale electricity prices are obtained from Prague Energy Exchange (PGE); Nordpool (Denmark); OMEL (Spain); OMIP (Portugal); APX (Netherlands); and European Energy Exchange (EEX) (Germany)

- the overall remuneration for the premium schemes are, in general, higher than that of the fixed tariff schemes – the higher tariffs for the premium tariffs are intended to offset the higher risks associated with the volatility of electricity prices;
- the average remuneration is broadly uniform across all countries for the mature technologies such as on-shore wind as already highlighted;
- there is a wide variance in remuneration for a solar PV plant with Germany offering the most generous minimum tariffs; and
- the average rent for fixed tariffs over and above wholesale electricity prices also differ across countries – fixed tariff remuneration is was always higher than the wholesale price of electricity.

Table 12 – Overall remuneration and support duration for selected countries

Tariff level in 2008 [€ Cents/kWh] and duration of support for different technologies

Country		Small hydro	Wind onshore	Wind offshore	Solid biomass	Biogas	PV	Geothermal
Czech Republic	Fixed	10.40 15 yrs.	9.84 15 yrs.	–	10.08 – 16.84 15 yrs.	13.2 – 15.6 15 yrs.	53.84 15 yrs.	17.2 15 yrs.
	Premium	12.07 15 yrs.	13.95 15 yrs.	–	11.43 – 18.19 15 yrs.	14.55 – 16.95 15 yrs.	57.07 15 yrs.	19.37 15 yrs.
Denmark	Fixed	–	–	–	8.0 10 yrs.	8.0 10 yrs.	20.0 – 25.0 20 yrs.	6.9 20 yrs.
Germany[1)]	Fixed	7.65 – 12.67 20 yrs.	9.2 20 yrs.	13.0 - 15.0 20 yrs.	7.79 – 22.67 [2)] 20 yrs.	7.79 – 29.67 [2)] 20 yrs.	31.94 – 43.01 20 yrs.	10.5 – 20.0 20 yrs.
Netherlands	Fixed	–	–	–	14.7 10 yrs.	–	–	–
Portugal	Fixed	7.5 – 7.7 15 yrs.	7.4 – 7.5 15 yrs.	7.4 15 yrs.	10.2 – 10.9 15 yrs.	11.5 – 11.7 15 yrs.	31 – 47 15 yrs.	–
Spain	Fixed	7.8 25 yrs.	7.3 20 yrs.	–	14.6 – 15.9 15 yrs.	8.0 – 10.8 15 yrs.	23.0 – 44.0 25 yrs.	6.9 20 yrs.
	Premium	8.66-9.06 no limit.	9.46 no limit	20.66 – 22.96 no limit	16.56 – 18.06 no limit	15.96 no limit	–	10.36 no limit

1) For installations commissioned 2009 according to the new EEG from June 2008
2) Maximum value is only available if all premiums are accumulated (premiums for innovation technologies, CHP, sustainable biomass etc.)

Source: Fraunhofer ISI and EEG

3.3 Evaluating and comparing the performance of schemes

Following choice of country FIT schemes and a high level review of the characteristics of the selected schemes; this section compares and evaluates the performance of the schemes based on a simple methodology relating to the following, among other factors:

- performance against policy objectives such as increasing the share of RES-E in electricity supply, carbon savings targets etc; and
- structural features and the administrative performance of the scheme – e.g. simplicity, transparency, effectiveness, and level of administration costs.

3.3.1 Comparing the policy performance of schemes

There are several policy objectives in instituting a FIT scheme as discussed in Section 1, these include but are not limited to:

- environmental imperatives – to increase the installed capacity of RES-E and the amount of renewable electricity they produced, and as a consequence, GHG emission reductions;
- security of supply - diversifying the electricity portfolio and enhancing energy security[53] by increasing proportion of domestic or EU supply; and
- economic / industrial policy considerations – development of RES-E sector to create new industries and jobs and to drive technological innovations.

The choices are influenced by the specific country policy objectives.

3.3.1.1 Developing a comparative framework

In this section, we review the performance or effectiveness of the selected schemes on the basis of these measures.

Table 13 below highlights a simple comparative framework adopted to compare the selected schemes based on each of the policy objectives identified. The methodology consists of simple quantitative measurements and supporting qualitative assessments.

Table 13 – Comparative framework for rankings based on policy objectives

Criteria	Methodology and sample measures
Increase in renewable generation or small scale generation	Includes quantitative assessment of incremental volume and percentage of renewables in total supply over a defined period that the scheme has been operational, differentiated by technology and scale. We have adjusted for other drivers of RES-E increase such as ease of loans and grants (in order to exclude other extenuating circumstances)
GHG emission reductions / carbon savings targets	Includes quantitative assessment of annual volumes of carbon abated in the electricity supply as measured by changes in supply and carbon content per KWh of electricity supplied during the period, as well as other qualitative measures, such as changes in demand / industrial structure, and fuel switching
Security of supply	Includes quantitative assessment of the share of indigenous resource-based generation and changes in measure of diversity of fuel mix (as measured by the Shannon-Wiener index) as well as qualitative assessment of influence of renewables in system reliability

53 Note that in our definition of security of supply here, we are not considering the effect of possible increase in the intermittency of supply, which would also impact on system security.

Economic and industrial policy objectives	Includes qualitative assessment of the economic contributions of the RES-E sector including number of jobs created and the turnover in the RES-E supply chain

Source: Pöyry Energy Consulting

Table 14 – Table 17 below provide sample metrics and comparisons used to compare and rank the selected FIT schemes. These are intended to give a high-level sense of country or scheme performance, the full metrics are available for each country in the Annexes. Moreover, we have made adjustments and subjective qualitative review of the schemes to arrive at our full qualitative rankings presented in Table 18.

Table 14 – Effectiveness in increasing renewable or small scale generation

Take up of RES-E technologies over 2000[1)] - 2005 (MW) and average annual growth per annum (%)

Country	Wind	Solid biomass	Biogas	PV
Czech Republic	28 (96.1% p.a)	1,182 –	36 –	–
Denmark	737 (5.5% p.a)	498 (46.7% p.a)	24 (9.7% p.a)	2 (24.6% p.a)
Germany	12,316 (24.7% p.a)	879 (50.6% p.a)	729 (25.5% p.a)	1,781 (79.8% p.a)
Netherlands	318 (16.2% p.a)	183 (46.4% p.a)	–	5 (5.3% p.a)
Portugal	981 (66.6% p.a)	54 (4.5% p.a)	7 (51.6% p.a)	1 (14.9% p.a)
Spain	6,111 (30.4% p.a)	194 (18.1% p.a)	91 (23.0% p.a)	25 (25.3% p.a)

1) For the Netherlands the figures are for the period from 2003, when the FIT scheme was instituted, to 2005

Source: Pöyry analysis based on IEA data

Table 15 – Effectiveness in reducing GHG emissions and meeting carbon targets

Scheme	Sample measurement metrics used
Germany	Electricity system CO_2 emission declined by 52g/KWh from 2000-2005 (averting ~46.7 MT of CO_2 emissions over the period) – growth in RES-E generation accounted for approximately 79.7% of the reduction, while fuel switching from coal to gas accounted for the majority of the rest.
Spain	Electricity system CO_2 emission decreased by 19g/kWh from 2000 – 2005 (averting ~35 MT of CO_2 emissions over the period) – RES-E decreased as a component of system generation due largely to massive fluctuation in hydroelectric output, however, RES-E increased in absolute terms. Without this increase, the CO_2 emission rate would have only decreased by 1g/KWh, assuming the same demand and an equal sharing of the energy differential due to renewables among the different fossil fuel based technologies.
Denmark	Electricity system CO_2 emission rate declined by 93g/KWh from 2000 to 2005 (averting ~5.7 MT of CO_2 emissions over the period). Growth in RES-E accounted entirely (100%) for the reduction.
Czech Republic	Electricity system CO_2 emission rate declined by 45g/KWh from the inception of the FIT scheme in 2002 to 2005 (averting ~11 MT of CO_2 emissions over the period), growth in RES-E accounted for approximately 2.5%, the remaining share of decarbonisation (97.5%) was due to increase in nuclear.
Netherlands	Electricity system CO_2 emission rate declined by 23g/KWh since the introduction of the scheme in 2003 to 2005 (averting ~3.5 MT of CO_2 emissions over the period), - growth in RES-E accounted almost entirely (approx. 99%) for this reduction.
Portugal	Electricity system CO_2 emission rate increased by about 38g/kWh from 2000 – 2005 due to a decline in renewable electricity as a component of the system as well as absolute capacity decline in RES-E from 13.13 TWh in 2000 to 8.56 TWh in 2005. This was mainly due to massive fluctuation in hydroelectric production from 11.7 TWh to 5.1 TWh. However, wind generation, increased significantly from 0.2 TWh (0.46% of system) to 1.8 TWh (3.86% of system) over the period. Without this increase, the systems CO_2 emission rate would have increased by roughly a further 22g/kWh.

Source: Pöyry analysis based on IEA electricity generation data

Table 16 – Effectiveness in meeting security of supply objectives

Scheme	Sample measurement metrics used
Germany	System diversity as measured by the Shannon Wiener Index[54] increased from 1.281 to 1.562 from 2000-2005, and corresponds to a decreasing fossil fuel composition of the system in contrast to an increasing RES-E composition. The net share of fossil fuel based electricity generation as components of the system decreased by 4.8% over the period, while RES-E, excluding pump storage output, increased by 3.6%.
Spain	System diversity as measured by the Shannon Wiener Index increased from 1.624 to 1.755 between 2000-2005, which refers to an improvement of the distribution between the various primary energy sources, although the net fossil fuel composition of the electricity system actually increased over the period from 55.2% to 62.6%.
Denmark	System diversity as measured by the Shannon Wiener Index increased during from 1.385 to 1.403, 2000-2005 – corresponding to decreasing fossil fuel composition of the electricity system in contrast to an increasing RES-E composition. Share of coal, gas, and oil generation as components of the system decreased by 3.7%, 8.5%, and 0.1% respectively, while RES-E increased by 12.5%.
Czech Republic	System diversity as measured by the Shannon Wiener Index increased from 0.984 to 1.026, 2002-2005, corresponding to decreasing fossil fuel composition of the electricity system generation in contrast to an increasing nuclear generation composition. Electricity from renewable energy plants increased in absolute terms over the period, but decreased as a share as the system electricity generation composition.
Netherlands	System diversity as measured by the Shannon Wiener Index increased from 1.090 to 1.141, 2003-2005, and corresponds to a decreasing fossil fuel composition of the electricity system's generation in contrast to an increasing RES-E composition. Share of coal, gas, and oil generation as components of the system fell by 1.7%, 0.7%, and 0.86% respectively, while RES-E generation grew by 3.39%, over the period 2003 – 2005.

[54] The Shannon Wirner Index is a diversity index used to measure diversity in categorical data, as a measure of diversity, as it is robust and an accepted indicator in energy supply. It is calculated as the sum of each fuel share multiplied by its log (values closer to 0 represent lack of diversity, while values greater than 2 represent signifcant levels of diversity).

Portugal	Despite a massive reduction (11.62%) in renewable energy as a component of the system, and the consequent increase in the system CO_2 emission rate, the diversity of the system increased marginally over the period 2000 – 2005 due to a more even distribution of the system electricity generation in 2005 between the four main sources (coal, gas, oil, and renewables). The Shannon Weiner index increased from 1.525 in 2000 to 1.582 in 2005.

Source: Pöyry analysis based on IEA electricity generation data

Table 17 – Effectiveness in meeting wider economic and industrial objectives

Scheme	Sample measurement metrics used
Germany	Over 250,000 jobs created to date (2008) and ~ €24.6 billion turnover from the installation and operation of RES-E plants. The wind sector employed 36,249 directly in turbine and component manufacturing at the end of 2007
Spain	As of the end of 2007, the wind sector employed 20,781 directly in turbine and component manufacturing and contributed directly €1.9 billion or 0.21% to GDP in 2008
Denmark	As of end of 2007, the wind sector employed 23,500 directly in turbine and component manufacturing
Czech Republic	The wind sector is largely confined to installations, and employed approximately 100 as of end of 2007
Netherlands	At the end of 2007, the wind sector employed about 2,000 directly in turbine and component manufacturing
Portugal	In 2009, the wind sector is expected to employ 3,800 directly in turbine and component manufacturing up from 800 in 2007

Source: Feed-in tariff cooperation and others

3.3.1.2 Ranking and comparisons of schemes

The selected schemes are ranked according to the metrics outlined above – as noted, the quantitative results summarised in the tables above are supplemented with anecdotal and subjective analysis from interviews with our country experts, and other literature reviews on the performance of the market to produce a ranking of the schemes summarised in Table 18 below.

The aim of the ranking and comparisons is to see how the selected schemes have performed on the metrics identified, and to establish the aspects of the schemes that have contributed to any or most of the performance or weaknesses of the scheme observed. The rankings are not intended as a definitive stand-alone assessment of the performance of any of the schemes analysed.

Table 18 – Ranking of selected schemes' observed policy performance

	Germany	Spain	Denmark	Portugal	Czech Rep	Netherlands
Deployment of RES-E (wind)	✔✔✔✔	✔✔✔✔	✔✔✔✔	✔✔✔	✔	✔✔
Deployment of RES-E (PV)	✔✔✔✔	✔✔*	✔	✔	✔	✔✔
GHG emission reduction	✔✔✔	✔✔	✔✔✔✔	✔	✔✔✔*	✔✔
Security of supply	✔✔✔✔	✔✔✔✔	✔	✔✔	✔✔✔	✔
Wider economic benefits	✔✔✔✔	✔✔✔✔	✔✔✔✔	✔✔✔	✔	✔✔

KEY: ✔ (poor); ✔✔ (median); ✔✔✔ (good); ✔✔✔✔ (best)

Source: Pöyry Energy Consulting, IEA Deploying Renewables Study, 2008

Germany and Spain rank high on achievement of almost all of the policy objectives identified, while the Czech Republic fares poorly in most objectives. Denmark and Portugal fare very well in selected objectives and poorly on others, while the Dutch scheme performs evenly across the board, but as a moderately successful scheme.

Deployment of wind

Germany, Spain and Denmark have been highly successful in promoting investment in wind through a mix of high tariffs and supportive investment and stable regulatory framework, and first mover advantages in the market (in technical and regulatory terms), among other factors.

Deployment of PV

Spain and Germany have experienced significant uptake, while the Czech Republic was deemed poor in terms of solar PV deployment because there were no installation of the technology for the period reviewed (although the market has seen significant new take-up in 2009). The reasons for high take-up and volatility in take up as the case for Spain indicates is due to high tariffs providing attractive rates of return, supportive regulatory and investment framework, among other factors.

GHG emission reduction

The high take-up of RES-E in Germany and Denmark encouraged in part by the FIT scheme, corresponding with fuel switching from coal to gas, explain their strong performance in GHG emission reductions. Although the Czech Republic was given a good ranking with regard to GHG emission reduction, it is worth noting that the decarbonisation of its electricity system was largely due to increased generation from nuclear plants, rather than from RES-E plants. Portugal's scheme was poorly ranked since GHG emissions actually increased over the period reviewed. This is despite an significant increase in wind and is due largely to massive fluctuations in the output from hydro-electric plants.

Security of supply

The high take-up of RES-E also improves performance in security of supply as the performance of Spain and Germany indicates. Most renewable sources are largely domestic, with the exception of biomass which is sometimes imported, however by increasing the role of these sources, Germany has broadened its portfolio and not only increased supply from domestic sources but reduced overreliance from a few sources, however this may comes at a cost of system reliability, since, for example, wind generation is intermittent.

Wider economic benefits

Germany, Denmark and Spain were pioneers and have moved aggressively to encourage a greater economic role for renewable energy as an explicit part of industrial policy; in part, this explains their strong performance on this criterion.

3.3.2 The role of policy framework and other incentives

It is important to note that the successes of the schemes discussed above (to the extent identified) have not been in a vacuum but are highly dependent on other factors such as complimentary fiscal incentives, a supportive regulatory environment and other societal factors, some of which are briefly highlighted below.

3.3.2.1 Role of fiscal incentives as a complimentary to FIT in increasing deployment

Fiscal incentives have played an important complementary role to tariffs in promoting uptake of renewable energy. Even with high tariffs, newer technologies (such as solar PV), smaller projects or project developers without a proven track record often experience difficulties in obtaining commercial loans at reasonable conditions – government guarantees or soft loans coupled with investment subsidies, capital grants and preferential tax treatments have helped bridge this divide.

In Germany for instance, KfW Bank, a state-owned lender has been instrumental in providing low cost finance and was a major force behind the 100,000 solar roof programme that launched the domestic solar sector. Similar incentive schemes in Spain offered by ICO-IDAE have supported the increased deployment of small scale generation.

The successes of the FIT schemes in Germany and Spain should be viewed in the context of not just a successful design of the scheme, but also the complimentary and important role played by other factors such as fiscal incentives in lowering the hurdle rates and risks for small scale investors.

Fiscal incentives in Germany and Spain

In Germany the KfW and DtA bank, as well as some regional (Bundesländer) programmes have over the last few years provided low interest loans for energy efficient and renewable energy investments. The KfW Umwelt (Environment) Programme for instance provides low interest loans to private companies and finances up to 75% of investment costs or a maximum of € 10 million. Typically loans are given for a period of 10 years, although 20 year terms are also provided. Interest rates depend on the capital market and range at the lower end of capital market rates.[55]

In Spain ICO-IDAE financing line provides support for investments in renewable energy. The maximum available is 70% of investment costs. Financing is open to both public and private organisations. The maximum loan size per project is € 6.3 million. An estimated € 150.2 million was available in 2002.[56]

3.3.2.2 Importance of scale

All the schemes reviewed apply across all scales – in contrast the GB scheme is intended for small scale generation, it is important therefore to isolate the successes, failures and lessons learnt for small scale generation as they are more closely applicable to the UK context. The biggest small scale success story is the solar PV sector in Germany and Spain, which as noted has primarily been driven by several factors, notably:

- High tariffs providing attractive rates of return complemented by generous fiscal incentives – at the start of the 100,000 Roofs programme in 1999, KfW for instance provided interest free loans and a waiver of the last instalment of up to 12.5%, equal to a subsidy of approximately 35%, this made solar PV an attractive investment proposition.
- Supportive regulatory and investment framework – in Germany as noted, the 100,000 Roofs programme was an explicit policy framework targeting solar PV.

Small scale wind generation has been a success in Denmark. The main driver was a tax exemption on revenue from cooperative wind enterprises, a provision that essentially doubled the income from a wind project because of a marginal tax rate close to 50%. This exemption dates back to at least 1985 and is a significant reason that cooperatives and households own over 80% of the Danish onshore capacity and indirectly, over 150,000 families.[57]

Besides the solar PV and selected cases in other technologies, growth in small scale generation in other sectors has been slow and the impact of FIT schemes less evident.

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55 KfW Press Release, KfW awarded loans of EUR 1 billion under its 100,000 Roofs Solar Power Programme, November 11, 2002.

56 Jager and Rathmann (2008).

57 Sørenson, Hans Christian, et al. Middelgrunden 40 MW Offshore Wind Farm Denmark –Lessons Learned. (After Johannesburg, Local Energy and Climate Policy: From Experience Gained Towards New Steps Wind Energy and Involvement of Local Partners – Munich September 2002).

3.3.3 Comparing the administrative performance of schemes

Administrative and regulatory barriers are crucial to the success of FIT schemes and to meeting the policy objectives identified above. Important characteristics highlighted in Section 2 include:

- Low administrative barrier (simplicity and transparency) – in general, the simpler and more transparent a FIT is, the greater is investors' confidence and, consequently, the higher the investment security. Conversely, schemes that are complex and less transparent generally increase the perceived risks to investors.
- High certainty to investors – a stable and long term policy framework is generally more investor friendly than one with a short policy framework, all other things being equal, as is a scheme that provides sufficient support level to cover generation costs of the respective RES-E technologies, inclusive of the return expectations of potential investors.
- High cost efficiency – high effectiveness at a minimal cost of deployment.
- Low regulatory barrier – compatibility with current market and policy arrangement and fewer transaction costs.

3.3.3.1 Developing a comparative framework

In this section, we review the performance or effectiveness of the selected schemes on the basis of their performance on administrative and regulatory barriers following a similar methodology used in assessing performance against policy objectives.

Table 19 below highlights a simple comparative framework adopted to compare the selected schemes based on each of the features identified. The methodology consists of simple quantitative measurements (where applicable) and supporting qualitative assessments.

Table 19 – Comparative framework for rankings based on structure and performance of scheme

Criteria	Methodology and sample measures
Degree of administrative barriers (simplicity and transparency)	Qualitative assessment of degree of transparency – complemented by interviews with investors and stakeholders, and review of procedures for clarity. This is backed up by findings from major studies found in the literature.
Cost of deployment	Simple quantitative assessment of distribution of costs
Certainty to small scale investors	Quantitative and qualitative assessment – complemented by interviews with investors and stakeholders and review of parameters such as duration of obligation, framework of review, policy on grandfathering tariffs etc for a high-level assessment of certainty
Transaction / administrative costs	Quantitative assessment of costs per unit of RES-E generated based on reading of regulatory framework,

Pöyry Energy Consulting	interviews with investors and stakeholders, complemented by review of transaction costs accruing to plant owner as per the regulatory framework e.g. who bears purchase and forecast obligation, grid cost charging methodology, and tariff administration costs

Table 20 below, for example, gives a picture of the levels of certainty to investors (investment security) that the selected FITs provide.

Table 20 – Performance of schemes in terms of certainty to investors (investment security)

Scheme	Sample measurement metrics used
Germany	(a) In general, the guaranteed support period for applicable RES-E is 20 years – the only exceptions currently being a 15 year duration for the rehabilitation of hydro-electric plants above 5MW. Prior to 2009, small hydro-electric installations (new or rehabilitated below 5MW) received support for 30 year periods, which has now changed to 20 years. (b) Remuneration level is fixed (independent of electricity market price) and decreases over time due to degression, but the reductions are well established and provide certainty of support and investor security.
Spain	(a) There is no limit on the policy support duration; however, fixed tariffs are reduced after either 15, 20 or 25 years depending on the specific RES-E technology. (b) Remuneration is based on both fixed and premium (electricity market driven) schemes. Under the premium scheme, the remunerations levels are typically greater than the fixed scheme to account for investors requirement for higher profitability for increased risks. For the fixed scheme, the support levels are well established and provide high investor security.
Denmark	(a) In 2006, all applicable RES-E were guaranteed support for a period of 20 years. In 2008, some RES-E are guaranteed support for 20 years while others are only guaranteed for 10 years. (b) Remuneration is fixed (independent of electricity market price) and provide stability of support. Also, the support levels are well established and provide investor security.
Czech Republic	(a) In 2008 as well as in 2006, all applicable RES-E were guaranteed support for a period of 15 years. (b) Remuneration is based on both fixed and premium (electricity market driven) schemes. Under the premium scheme, the remunerations levels are typically greater than the fixed scheme to account for investors' requirement for higher profitability for increased risks. For the fixed scheme, the support

	levels are well established and provide investor security.
Netherlands	(a) In 2008 as well as in 2006, all applicable RES-E were guaranteed support for a period of 10 years. (b) New "sliding premium" scheme introduced in 2008, where premium is based on average electricity price and decreases linearly with increasing electricity prices. This adds to the administrative complexity of the scheme, but minimises the risk of over and under compensation to investors.
Portugal	(a) In 2006, all applicable RES-E were guaranteed support for a period of 15 years, however this was changed to a support period of 10 years in 2008. (b) There is much uncertainty for investors and plant operators, because the level of remuneration depends on many parameters and the tariff level is difficult to edict

Source: Pöyry analysis based on Fraunhofer ISI and EEG data

3.3.3.2 Ranking and comparisons of schemes

Table 21 – Ranking of selected schemes' observed performance based on structure and performance of scheme

	Germany	Spain	Denmark	Portugal	Czech Rep	Netherlands
Simplicity and transparency	✔✔✔✔	✔✔✔	✔✔	✔	✔✔✔✔	✔✔
Cost of deployment	✔✔✔	✔✔✔	✔✔✔	✔✔	✔✔	✔✔
Certainty to small scale investors	✔✔✔✔	✔✔✔✔	✔✔✔	✔✔	✔✔✔✔	✔✔
Transaction costs	✔✔✔	✔✔✔	✔✔	✔✔	✔✔✔	✔✔
Wider economic benefits	✔✔✔✔	✔✔✔✔	✔✔✔✔	✔✔✔	✔	✔✔

KEY: ✔ (poor); ✔✔ (median); ✔✔✔✔ (good); ✔✔✔✔ (best)

Source: Pöyry Energy Consulting; IEA Deploying Renewables Study, 2008

Germany, Spain and the Czech Republic rank high on performance based on structure and performance of the scheme, while Portugal fares poorly, and Denmark and the Netherlands rank in the intermediate.

Simplicity and transparency

Germany, Spain and the Czech Republic rank high due to offering fixed tariff that are clearly differentiated by scale and have clearly specified duration. For Germany, some components of scheme are highly transparent (e.g. well established degression design), others give rise to high administrative complexity (e.g. for defining a reference plant in the stepped design).

At the other end of the spectrum, Portugal's scheme ranks poorly because it is difficult to determine the level of remuneration payable as it is based on a complex formula dependent on: cost of CO_2 emissions avoided, time of generation (night or day), inflation, and avoided electricity losses, which introduces unnecessary administrative complexity

Cost of deployment, distribution of costs and impact on consumer prices

Germany and Denmark apply an equal burden sharing among all electricity consumers but provide relief to electricity intensive industries. Spain, the Czech Republic and Portugal similarly provide for equal burden sharing, however in the Netherlands, each electricity consumer contributes the same amount of money to RES-E support, regardless of the amount of electricity consumed.

Certainty to small scale investors

Germany, Spain and the Czech Republic rank well on this score based on their fixed tariff offerings which provide well established support levels and provide high investor security. Portugal ranks poorly because the level of remuneration depends on many parameters and the tariff levels are difficult to predict.

Transaction costs

Germany, Spain and the Czech Republic similarly rank highest – these schemes allow minimal transaction costs, since there are reasonable degrees of conformity with the power market structure and other policy instruments.

3.4 Conclusions and Insights from comparisons

The case studies on the selected FIT schemes discussed in some detail above highlight not only the high level of permutations possible in the design of FIT schemes, but also the predominance of several key features, including:

- Choice of fixed or premium tariffs – as outlined in Section 2.1, there are pros and cons to having a market based tariff (premium) as compared to a non-market base tariff (fixed). For small generators, fixed tariffs are preferable for non-dispatchable RES-E plants – the transaction costs of participating in the market, and the risk / uncertainty of electricity prices outweigh the benefit of easier grid management. However for dispatchable technologies (biomass- and gas-fired CHP) premium choice may provide appropriate signals. The examples above seem to validate this recommendation with a large number of schemes (78% of the distinct options provided) offering fixed tariffs.
- Differentiation by scale and technology allows support to RES-E plants to be moderated according to the fundamental drivers of the plants costs, and hence regulates the profitability of RES-E projects. As noted majority of schemes are both stepped or banded

and with technology differentiation – 39% of all options available provide both technology, scale and /or other differentiation in tariffs.

- The comparison also reveals common reasonable length of guaranteed payments –the support frameworks, in most cases, are in excess of 10 years. It may be worth noting that the most successful schemes, such as the German and Spanish schemes, had very long policy frameworks, in the order of 20 years. Reinforcing other results on best practices that suggest that support frameworks should match up with the economic life span of RES-E generating facilities or common durations for debt financing.
- Degression is not yet a common feature, but may become a common parameter. Of the schemes analysed, Germany was the only scheme with any significant experience in applying tariff degression. Degression has only very recently been introduced in the Spanish and Czech FIT schemes. Since the Spanish scheme, for example, has achieved fairly high effectiveness before degression was introduced, it could be argued that the omission of this feature should not necessarily hinder the possibility of achieving high policy effectiveness. However, since an underlying goal is to achieve high policy effectiveness at minimal cost, it may yet become a best practice to incorporate degression into FIT schemes. The German experience has shown that well defined technology specific degression rates provide higher levels of investor certainty and transparency than attempts to address plant costs reductions in frequent reviews.
- The case studies also reveal the importance of clear guidelines for tariff review and adjustments, including review timing and impact on existing installations. These have an important bearing on investor certainty and transparency. The German approach, which is perhaps the best model, is to perform a review after the first year of implementation to ensure that the scheme is working as anticipated – followed by subsequent revisions every three years.

It is important to highlight that the successes or failures of each of the schemes mentioned have also been a result of other drivers besides the policy framework and operation of the FIT scheme. As noted, the prevalence of generous tariffs and soft loans was equally important in stimulating deployment in Germany and Spain. Moreover, with the exception of Solar PV in Germany and Spain and the Danish onshore wind sector, there is no clear evidence that the schemes have been successful in encouraging smaller scale generation. Finally, the electricity sector and market arrangements in each of the countries differ and may have played a factor in the successes observed and could boost or mute the effects of some of the design options discussed above.

3.5 International best practices literature review

Research into feed-in tariff best practices highlights a number of important features common to successful FIT schemes. In this section we present a summary of the key attributes of a successful FIT design and other important insights, from the literature, with a view to further documenting best practices and recommendations for the UK.

The studies reviewed include:

- OPTRES: Assessment and optimisation of renewable energy support schemes in the European electricity markets – commissioned by DG TREN, European Commission (Intelligent Energy Europe) and conducted by a consortium led by Fraunhofer ISI.

- Deploying Renewables: Principles for Effective Policies – a study by the International Energy Agency (IEA) published in 2008 highlighting principles for effective policies in deploying renewables.
- Evaluating different feed-in tariff design options – Best Practice Paper for the International Feed-In Cooperation, 2nd edition – commissioned by the German Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU) and other partners in the International feed-in cooperation (IFIC) consortium, and conducted by Fraunhofer ISI and EEG.
- Other literature reviews, discussions with experts from the Energy Economics Group (EEG), Vienna University of Technology; Pöyry and Element Energy and with selected investors and stakeholders.

3.5.1 OPTRES- Assessment and optimisation of renewable energy support schemes in European electricity markets (2007)

The OPTRES study highlights a few key characteristics of successful schemes summarised below, these include:

- supporting the full basket of technologies which can be reasonably utilised;
- setting financial support level at a higher cost than the marginal cost of generation from the RES-E plants;
- considering only new installations when reviewing, adapting or changing the scheme; and
- restricting the timeframe for support.

In addition, the study highlighted a few lessons specific to choice of design parameters that are highlighted in Table 22 below:

Table 22 – OPTRES findings on the design of successful FIT schemes

Design parameter	Findings / recommendations
Banding	Implement a FIT scheme in a stepped (band specific) way, in order to reduce the costs for consumers - a stepped design can clearly increase the efficiency of the incentive especially in countries where the productivity of a technology differs a lot between different technology bands
Degression	In order to enforce technological learning, a decrease of the offered tariff for new contracts over time should be implemented and clearly communicated
Length of guarantee	The policy instrument should remain active for a sufficient period to provide stable planning horizons. Following, stop-and-go policies are not suitable, and an implemented project should not be faced with a change of support scheme during lifetime.
Investor security	Secure stability for investors in RES-E technologies

Source: OPTRES

3.5.2 IEA – Deploying Renewables: Principles for Effective Policies

The IEA (2008) study, which highlights principles for effective policies in deploying renewables, argues that a successful FIT scheme needs to:

- implement a stable policy framework with low administrative and regulatory barriers to guarantee high investment stability;
- ensure relatively favourable grid conditions exits; and
- ensure appropriate level of IRRs across different investors and technologies.

For each technology, the study highlights a few lessons that are highlighted in Table 23 below:

Table 23 – IEA findings on the design of successful FIT schemes

Technology	Findings / recommendations
Wind	There is a minimum threshold remuneration of 7 US cent/kWh (2005 dollars) that seems to be necessary to initiate deployment – beyond the threshold; remuneration does not necessarily correlate with policy effectiveness. Performance for wind is also related to the availability of fairly good wind resource
Solar PV	High effectiveness (in Germany and Luxembourg) seem to be tied to very high remuneration. Other key features of a successful PV policy includes net metering, favourable retail rate structures and streamlined inter- connection rules – these have been shown to be important triggers for PV market take-off. However, net metering is not compatible with FIT schemes.
Biomass	Success for biomass seems dependent on availability of abundant biomass combined with the opportunity for co-firing in coal boilers. The threshold remuneration level of 8 US cent/kWh (2005 dollars) is necessary to initiate deployment
Biogas	Countries where there is expansion of landfill gas capacity producing methane (relatively cheap biogas feedstock) have been shown to be most successful. Level of support necessary to create financially viable projects highly depends on specific fuel used. Further countries using FIT often implement very different remuneration levels for the promotion of different biogas technologies, and differentiate by size of installation

Source: Deploying Renewables: Principles for Effective Policies, IEA, 2008

3.5.3 International feed-in cooperation

The international feed-in cooperation (IFIC) study identifies the following key attributes of a well designed FIT scheme, these include:

- providing technology specific support with due respect to the future potential of the different technologies;
- setting targets for technological progress;
- is cost efficient and avoids windfall profits to RES-E projects;
- can give incentives to RES-E plants to participate in the liberalised electricity market; and
- can be adjusted to changes in the market situation

3.5.4 Other findings from experts consulted

Other literature reviewed and our discussions with experts from the Energy Economics Group (EEG), Vienna University of Technology; Pöyry and Element Energy and with selected investors and stakeholders, reinforces some of the findings mentioned. These are summarised in Table 24.

Table 24 – Other findings on the design of successful FIT schemes

Design parameter	Findings / recommendations
Choice of fixed vs. premium tariffs	For small generators, fixed tariffs are preferable for non-dispatchable RES-E plants – the transaction costs of participating in the market, and the risk / uncertainty of electricity prices outweigh the benefit of easier grid management. However for dispatchable technologies (biomass- and gas-fired CHP) premium choice may provide appropriate signals
Guarantee period	A guarantee period of at least 10-15 years enhances investment stability
Banding	Consider differentiation by technology and scale – and no more. This will provide the right balance between encouraging economic efficiency (and reducing rents) and limiting complexity – except for PV (building integrated vs. field-based systems) and/or biomass (fuel type)
Review period	A review after the first year to ensure overall design and support levels are driving the market as intended, and then limit reviews to formal 3-4 years, perhaps with an interim minimum adjustment if necessary
Capacity caps	Avoid capacity caps unless set sufficiently high so as not to artificially constrain uptake. Further, a cap higher than the required, predicted uptake could function as a backstop to constrain subsidy spend

Degression / review periods	For technologies with global learning rates, degression should rely on global technology cost reductions; for localised markets, consider feedback from market stakeholders

Source: IEA

3.6 Conclusions and Insights from literature review

The studies and literature reviewed that are briefly described above provide an indicative list of best practices. These include:

- Supporting the full basket of technologies which can be reasonably utilised - it may be beneficial in the long run for FIT schemes to also encourage the diffusion of immature and less competitive technologies, as evidence suggests that learning and scale economics lead to future cost reductions and more competitive portfolio of RES-E technologies.
- Choice of fixed vs. premium tariffs – for small generators, fixed tariffs are preferable for non-dispatchable RES-E plants – the transaction costs of participating in the market, and the risk / uncertainty of electricity prices outweigh the benefit of easier grid management. However for dispatchable technologies (biomass- and gas-fired CHP) premium choice may provide appropriate signals.
- Differentiating support by technology and scale in order to increase the efficiency of the incentive especially where the productivity of a technology differs a lot between different technology bands and to reduce the costs for consumers and rents for RES-E plants. Differentiation should also recognize the future potential of the different technologies.
- Setting financial support level at a higher cost than the marginal cost of generation from the RES-E plants. In general provide for a reasonable return necessary to initiate deployment, however beyond a certain threshold, remuneration does not necessarily correlate with policy effectiveness.
- Considering only new installations when reviewing, adapting or changing the scheme. Consider a review after the first year to ensure overall design and support levels are driving the market as intended, and then limit reviews to formal 3-4 years, perhaps with an interim minimum adjustment if necessary.
- Restricting the timeframe for support for a sufficient period to provide stable planning horizons – 10-15 years is an appropriate starting point. Following, stop-and-go policies are not suitable, and an implemented project should not be faced with a change of support scheme during lifetime.
- Implementing a sensible and clearly communicated degression rate to enforce technological learning over time. For technologies with global learning rates, degression should rely on global technology cost reductions; for localised markets, consider feedback from market stakeholders on what level to set the degression.
- Providing complementary support policies targeted at specific technologies.
- Allowing conformity with the power market structure and other policy instruments, targets – ensure FIT can be adjusted to changes in the market situation.

- Avoiding capacity caps unless set sufficiently high so as not to artificially constrain uptake. Further, a cap higher than the required, predicted uptake could function as a backstop to constrain subsidy spend.

These best practices provide an important list of what to do and what not to do in the design of a GB scheme. However, it is important to highlight that these best practices result from FIT schemes that apply across all scales. Given the GB scheme's unique focus on small scale generation, these may need to be modified in order to engender the same levels of take-up that have been experienced by the more successful schemes such as Germany and Spain. In addition, there are significant differences in the structure of the electricity sector and market arrangements between countries that have an important bearing on the success of individual parameter choices.

4. CONCLUSIONS AND INSIGHTS

The government has expressed its intention to implement a system of feed in tariffs (FITs) covering low carbon electricity generation up to 5MW capacity to support the exploitation of small scale generation. This report:

- reviews how a FIT scheme would work in practice, highlighting the implications of the different design options; and
- details insights and best practices from other country experiences, and from the literature, which are useful in guiding the development of a GB FIT scheme.

The methodology employed in Section 2 and 3 involves three interrelated frameworks:

- a review of individual design parameter options;
- a detailed assessment of selected FIT schemes; and
- a summary of selected findings from literature review.

Collectively the analysis, studies and reviews highlighted provides an indicative list of best practices useful in guiding the design of the GB scheme, both on key success factors to emulate but also on what not to do. These are highlighted in Table 25 below:

Table 25 – Insights on choice of parameters in the design of successful FITs

Design parameter	Key findings / insights
Choice of fixed vs. premium tariffs	For small generators, fixed tariffs are preferable for non-dispatchable RES-E plants – the transaction costs of participating in the market, and the risk / uncertainty of electricity prices outweigh the benefit of easier grid management. However for dispatchable technologies (biomass- and gas-fired CHP) the premium option may provide appropriate signals to generate at times of high value.[58]

58 Fixed tariffs remain the dominant choice for most FIT schemes in Europe, Of all the 50 distinct sets of choices offered in Europe, 78% offer fixed tariffs.

Setting the initial tariff level	To ensure uptake, financial support should be set at a level that is sufficient to deliver investment, but which does not over-compensate investors. The various RES-E technologies have specific minimum remuneration thresholds that seem to be necessary to initiate deployment – beyond these thresholds; remuneration does not necessarily correlate with policy effectiveness.[59] The initial feed-in tariff level should at a minimum apply a rate of return, equal to a standard investor hurdle rate, to the specific cost of generating electricity from the RES-E plant. Where data exists for existing generation plants this should be incorporated into cost estimates. However, with the recent volatility seen in equipment costs the setting of the initial tariff level needs to factor in possible short-term developments. In addition, inflation and exchange rates should be considered in establishing the initial tariff level and subsequent revisions, as this affects power generation costs.
Differentiation or banding	Differentiating support by technology and scale in order to increase the efficiency of the incentive especially where the productivity of a technology differs significantly between different technology bands and to reduce the costs for consumers and rents for RES-E plants. Differentiation should also recognize the future potential of the different technologies. To limit complexity it is suggested that the scheme should differentiate by technology and scale for all technologies, but limit any further banding beyond this – except for PV and biomass where a further layer may be considered: for PV (building integrated vs. field-based systems) and biomass (fuel type)
Appropriate level of tariff	The FIT should provide appropriate signals to encourage the deployment of the most cost effective technologies and resources first, but support the full basket of technologies which can be reasonably utilised – it may be beneficial in the long run for FIT schemes to also encourage the diffusion of immature and less competitive technologies, as evidence suggests that learning and scale economics lead to future cost reductions and more competitive portfolio of RES-E technologies.

59 There are many studies that have attempted to quantify the hurdle rates or cost of capital for other countries, or for specific investor class or type of support instrument for RES-E plants in Europe. OPTRES (2007) for instance estimates that the average RES-E project in Europe supported by a fixed FIT would incur a weighted average cost of capital (WACC) of 6.5% rate, compared to 7.55% (premium FIT); 7.55% (tender scheme; 8.6% (quotas or tradable green certificates) and 8.6% (tax incentives). Jager and Rathmann (2008) calculate specific WACC for selected combinations of countries and technologies. Germany for instance has an average WACC of 4.5% (onshore wind), 4.2% (solar PV) and 6.6% (biomass CHP). In comparison, the UK rates are estimated at 6.5% (onshore wind) and 7.9% (biomass CHP).

Degression	Implementing a sensible and clearly communicated degression rate can enforce technological learning over time. For technologies with global learning rates, degression should rely on global technology cost reductions; for localised markets, consider feedback from market stakeholders on what level to set the degression.
Tariff revisions	Revisions of the scheme should consider only new installations when reviewing, adapting or changing the scheme. An interim review after the first year to ensure overall design and support levels are driving the market as intended is seen as appropriate, with formal reviews every 3-4 years thereafter perhaps with an interim minimum adjustment if necessary.
Duration of tariff support or guarantee period	There is no 'right' payback period, the timeframe for support needs to be for a sufficient period to provide stable planning horizons and financing arrangements – 10-15 years is an appropriate starting point. It is possible to consider shorter payback periods for instance 5-10 years as it could help overcome high discount rates and up front cost of capital experienced especially by households, however shorter payback periods may result in higher financing costs and the scheme may need to provide more generous remuneration, and/or other risk mitigation benefits to produce the same level of take-up.[60] Just as important as the payback period is policy commitment – an investment should face minimal or no change to its support scheme during the project's lifetime.
Capacity caps	Avoiding capacity caps unless set sufficiently high so as not to artificially constrain uptake. Furthermore, a cap higher than the required and/or predicted uptake could function as a backstop to constrain subsidy spend (in this regard a capacity degression works better than a cliff edge or automatic review cap).
Bonus incentives.	Providing complementary support policies targeted at specific technologies – for example, providing additional incentives for combined heat and power plants (CHP) with extremely high efficiency. Bonus incentive can enhance the prospect of achieving specific policy objectives, such as, driving technological innovation. However, the potential benefits must be weighed against the additional administrative complexity which they will introduce in the FIT scheme.

[60] Financiers are likely to attach higher risk premiums to shorter support periods since there would be greater economic impact in the case of shorter support periods if, for example, a RES-E project were to experience lower than expected availability during the first few years of commissioning. However, this also depends on whether investors discount at a higher rate than the social discount rate used in the government's assessment of the subsidy cost (shorter periods could also lower the overall cost of subsidy required to make the investment attractive for certain types of investors). See the Quantitive Report on Feed-in Tariffs issued alongside this report (Analysis of a Feed-in Tariff for Sub-5MW Electricity in Great Britain,

Interaction with market arrangements and regulatory framework	Allowing conformity with the power market structure and other policy instruments, targets – minimises market distortions and ensure FIT can be adjusted to changes in the market situation.
Administration and operation of the scheme	The preferred arrangement is for the scheme to be administered through the suppliers, which would have the responsibility of conducting the financial transactions for renewable electricity generation. The favoured approach is for the financing of the scheme to be recouped from electricity end users, with pre-defined arrangement between suppliers to deal with issues relating to asymmetrical RES-E distribution.

Source: Several sources (IEA, OPTRES, Fraunhofer ISI and EEG, and Pöyry analysis)

The generic recommendations noted above should be viewed in the context of several factors unique to the GB scheme under consideration which implies that some of the best practices may not necessarily apply in practice and may need to be modified to suit the UK context where appropriate.

The GB FIT would be unique in its focus on small scale generation – the Italian FIT scheme which allows sub-1 MW plants to choose between a FIT and green certificates is the only direct comparator – all other schemes detailed in this report apply across all scales. It is therefore difficult, but important to distinguish those best practices that apply particularly to small scale generation and would be more suitable in the UK context. Similarly, there are factors unique to the UK electricity sector which may make translation of other country experiences different from that of the UK. For example, distribution network operators are not licensed to generate or purchase electricity. Short of amending their licences, this implies that a purchasing obligation that is generally part of a fixed tariff regime would be difficult to implement, unless the obligation is transferred to suppliers. It also implies that payments and administration of the scheme may involve suppliers rather than DNOs as is common in schemes across Europe. These and many other features or market arrangements unique to the UK electricity sector implies that some of the best practices may need to be modified in order to apply to the UK context.

Building on the conclusions in Table 25, Table 26 identifies suggestions for the FIT design for individual technologies.

Table 26 – Conclusions and insights on choice of parameters

Design parameter	Design parameter	Onshore wind	Solar PV	Biomass CHP	Small hydro	Biogas	Wave and tidal
Primary parameters	Choice of tariff - fixed vs. premium	Fixed	Fixed	Fixed/Premium	Fixed	Fixed/Premium	Fixed
	Choice of flat vs. stepped tariff	Stepped	Stepped	Stepped	Stepped	Stepped	Stepped
	Technology differentiation	Yes	Yes	Yes	Yes	Yes	Yes
	Scale/ Local condition differentiation	Scale	Rooftop/ Façade (Building integrated) vs. Open space installations	Scale/ Fuel	Scale	Scale	None
	Apply Degression	Yes	Yes	Yes	Yes	Yes	Yes
	Level of degression	Medium	High	Low	Low	Low	Low
	Review period	3 yrs. (1st review after one year)	3 yrs. (1st review after one year)	3 yrs. (1st review after one year)	3 yrs. (1st review after one year)	3 yrs. (1st review after one year)	3 yrs. (1st review after one year)
	Setting initial tariff support level	Based on technology cost and hurdle rates. Apply reference plant approach	Based on technology cost and hurdle rates. Apply reference plant approach	Based on technology cost and hurdle rates. Apply reference plant approach	Based on technology cost and hurdle rates. Apply reference plant approach	Based on technology cost and hurdle rates. Apply reference plant approach	Based on technology cost and hurdle rates. Apply reference plant approach

Secondary parameters	Length of guarantee	lifetime of plant or 15-20 years	lifetime of plant or 15	20 years	lifetime of plant or 15	20 years	lifetime of plant or 15
	Capacity cap	No	No	No	No	No	No
	Purchase obligation	Yes	Yes	Yes / No (based on trade-off between investors' risk and grid management costs)	Yes	Yes / No (based on trade-off between investors' risk and grid management costs)	Yes
	Forecast obligation	No	No	No	No	No	No
	Bonus incentives	Repowering	None	Fuel efficient (CHP)	None	None	None
	Grid connectionpolicy	Shallow[61]	Shallow	Shallow	Shallow	Shallow	Shallow

Source: Pöyry Energy Consulting / Element Energ

61 In a shallow connection arrangement, RES-E plants pays for only the cost of equipment needed to connect to grid; upgrade cost are borne by the grid operator, who usually recovers by applying 'use of system' charges.

ANNEX A – GERMANY

A.1.1 Summary of scheme and history

Germany's feed-in tariff scheme was introduced in 1991 and has since undergone amendments in 2000, 2004, and 2009. It is the main RES-E support mechanism applied in the country and is complemented by the availability of abundant soft loans from the German government owned development bank, KfW, the DtA bank, as well as some regional (Bundesländer) programmes.

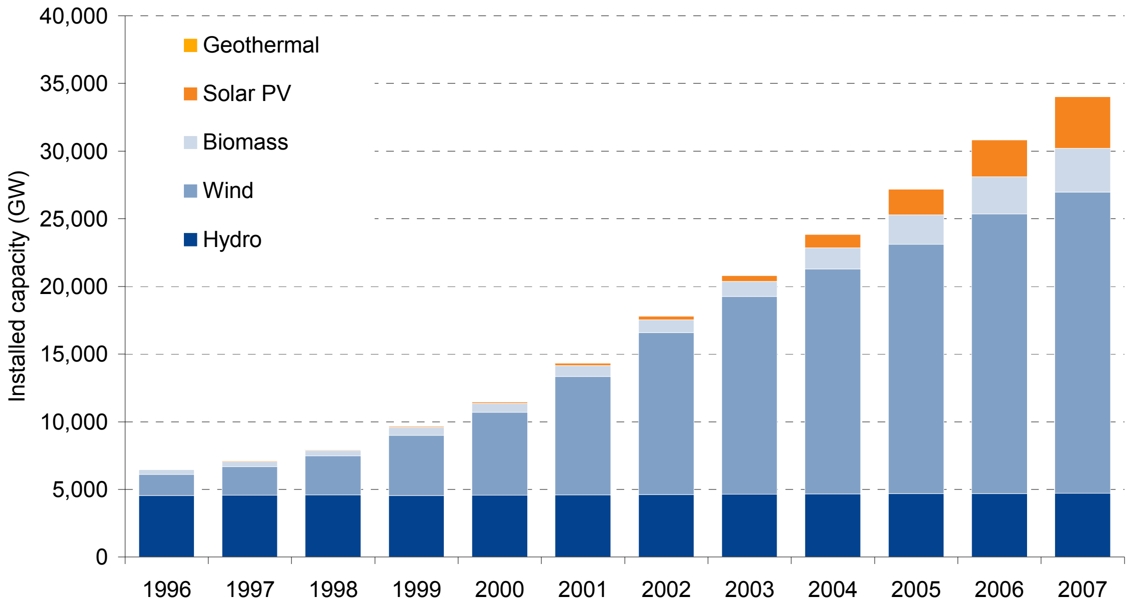
The FIT scheme applied in Germany provides technology specific, fixed tariffs with degression and scale/ local condition differentiation. Under the new EEG Act, each RES-E installation can switch between the FIT scheme and direct sale to the market on a monthly basis. The feed-in tariffs, which are typically guaranteed for a period of 20 years, are reviewed every three years.

A.1.2 Policy objectives performance

Germany's FIT scheme has achieved significant success over the years, which has resulted in Germany becoming a world leader in wind and solar PV RES-E deployment.

A.1.2.1 Increasing the deployment of renewables

Figure 6 – RES-E installed capacity trend, 1996 – 2007



Source: Pöyry Energy Consulting

Figure 6 shows the installed capacity trend of renewable electricity plants in Germany during the period 1996 to 2007, and presents a measure of the effectiveness of the FIT scheme over this timeframe. Between 1996 and 2007, wind generating capacity increased by 20,700MW (equivalent to an annual growth of 27.4%), solar PV capacity increased by 3,787MW (a 58.5% growth per annum), and biomass power generation capacity by 2,880MW (a 22.2% annual growth). Growth in wind and solar PV technologies have continued to rise exponential since 2007 – in 2008, for example, there were about 1,500MW of new solar PV installations.

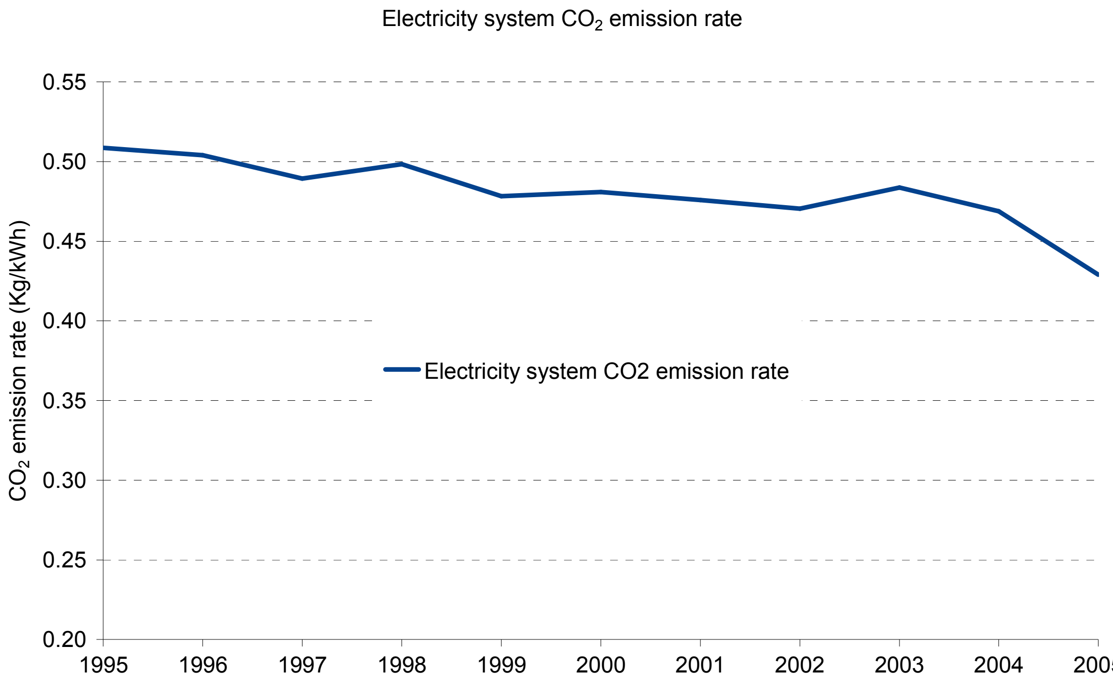
A.1.2.2 Decarbonisation and emissions reductions

Germany's electricity system CO_2 emission rate decline by approximately 52g/KWh over the period 2000 to 2005 (see Figure 7) – averting roughly 46.7 million tonnes of CO_2 emission. The growth in RES-E generation accounted for approximately 79.7% of the reduction, while fuel switching from coal to gas accounted for the majority of the remainder of the reduction.

A.1.2.3 Improving security of supply

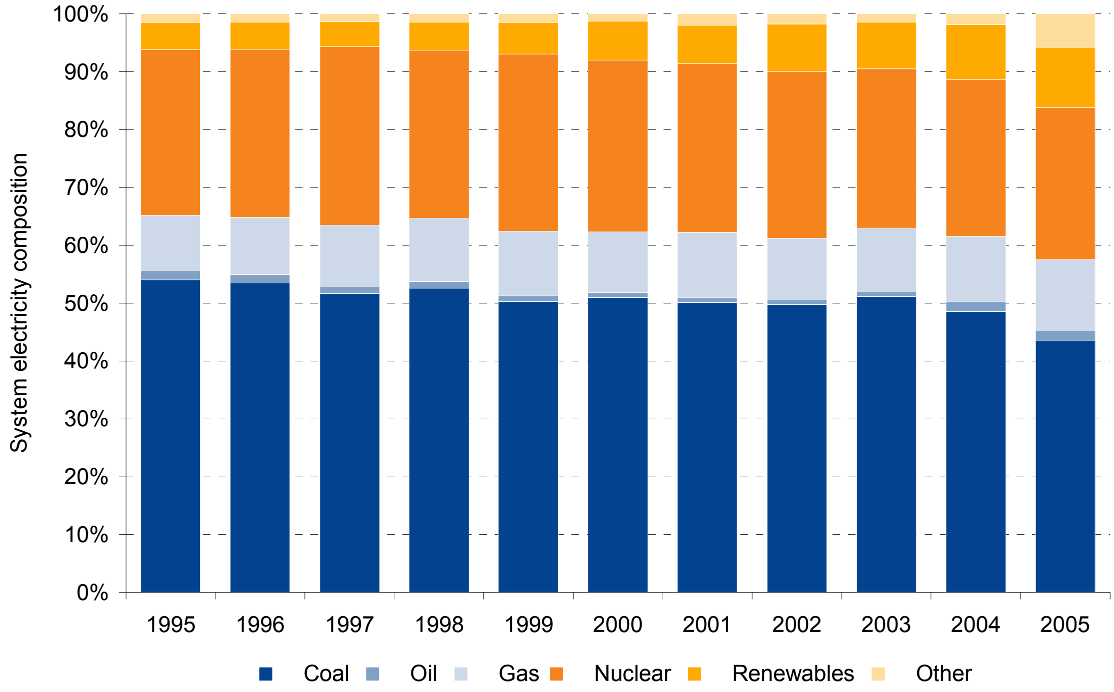
The diversity of Germany's electricity system, a proxy for its security of supply, increased during the period 2000 – 2005. This is evident from the increase in the Shannon Wiener index from 1.281 in 2000 to 1.562 in 2005, and corresponds to a decreasing fossil fuel composition of the electricity system generation in contrast to an increasing RES-E composition (see Figure 8). The net share of fossil fuel based electricity generation as a component of the system decreased by 4.8%, while RES-E generation, excluding pump storage output, increased by 3.6%, over the period 2000 – 2005.

Figure 7 – Electricity system CO_2 emission trend, 1995 – 2005



Source: Pöyry Energy analysis based on IEA electricity data

Figure 8 – Electricity system generation composition, 1995 – 2005



Source: IEA

A.1.3 Administrative performance

OPTRES (2007)[62] reports that the administrative barrier of Germany's FIT scheme is medium, giving it a score of 3.0 out 5, where a score of 0 represents no perceived barrier and 5 represents the highest perceived barrier.

Germany's FIT scheme's success is mainly attributed to its administratively simple and highly transparent characteristics and its stable policy framework.

A.1.3.1 Estimated investor returns

Analysis using a discount rate of 6.6% gives estimates of the respective costs of onshore wind, solar PV, biomass, and hydroelectric RES-E as follows: 9.8, 71.2, 4.4, and 6.9 € cents/kWh (real 2008 money). This is against the following respective upper limits of remuneration: 9.2, 43.0, 22.7, and 12.7 € cents/kWh (real 2008 money). These estimates suggest a mixed record of profitability, with incentives for biomass and hydro technologies particularly generous and conversely less so for onshore wind and solar PV technologies. However, the estimates ignore the availability of soft loans in Germany which have decreased the cost of capital for most investments. In addition accounting for higher capacity factor of wind turbines at the more attractive sites, should improve the profitability. (In the analysis an average capacity factor of approximately 20% was assumed for wind).

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62 Ragwitz et al, Assessment and Optimisation of Renewable Energy Support Schemes in European Electricity Markets, OPTRES, 2007

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ANNEX B – SPAIN

B.1.1 Summary of scheme and history

The Spanish FIT scheme was introduced in 1994 and is the main RES-E support mechanism in Spain. It is complemented by soft loans, tax incentives and regional investment incentives. The scheme, which provides relatively generous remuneration levels, provides investors with the choice between a fixed tariff and a premium tariff, with the exception of solar PV projects, which only enjoys the fixed tariff. The tariffs are differentiated by technology and scale, and their future trends are linked to the Spanish inflation minus a factor equivalent to -0.25% until 31 December 2012 and -0.5% afterwards. In the current scheme, tariffs are reviewed once 85% of the renewable energy target has been met for each individual technology. This is a change from previous implementations where tariffs were revised on more of an ad hoc basis.

There is no limit on the policy support duration; however, fixed tariffs are reduced after either 15, 20 or 25 years depending on the specific RES-E technology. Additional incentives are provided for repowering wind turbines.

B.1.2 Policy objectives performance

Spain, like Germany, is a world leader in wind and solar PV deployment. The solar PV market experienced a boom and a subsequent abatement in recent times – currently there are over 3,000 MW of installed solar PV generating capacity. The apparent abatement was mainly due to the revision of the tariffs for solar PV to much less attractive levels under a non-transparent review process.

B.1.2.1 Increasing the deployment of renewables

Over the period 2000 – 2005, wind generating capacity in Spain grew by 6111MW (equivalent to 30.4% growth per annum), solid biomass generating capacity grew by 194MW (18.1% growth per annum), biogas power generating capacity grew by 91MW (23.0% growth per annum), and solar PV generating capacity rose by 25 MW (25.3% growth per annum). Growth in wind and solar PV technologies have continued to increase at significantly high rates since 2005 – in 2008, for example, there were about 2,500MW of new solar PV installations.

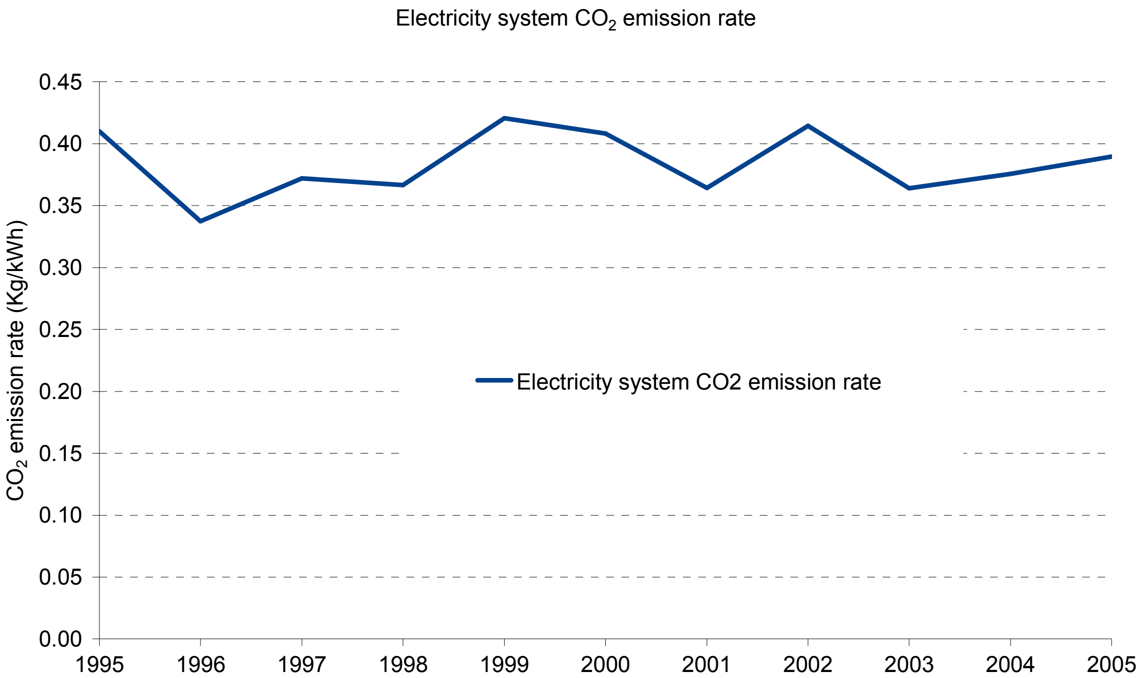
B.1.2.2 Decarbonisation and emissions reductions

Spain's electricity system CO_2 emission rate declined by approximately 19g/KWh over the period 2000 to 2005 (see Figure 9) – averting roughly 35 million tonnes of CO_2 emission. Renewable energy (RE) decreased as a component of system generation due largely to massive fluctuations in hydroelectric output from 29.47TWh in 2000 to 19.55TWh in 2005. However, RE increased in absolute terms – had this not occurred, the CO_2 emission would have only declined by about 1g/kWh (assuming that the energy differential due to renewables would be shared equally among the different fossil fuel based technologies).

B.1.2.3 Improving security of supply

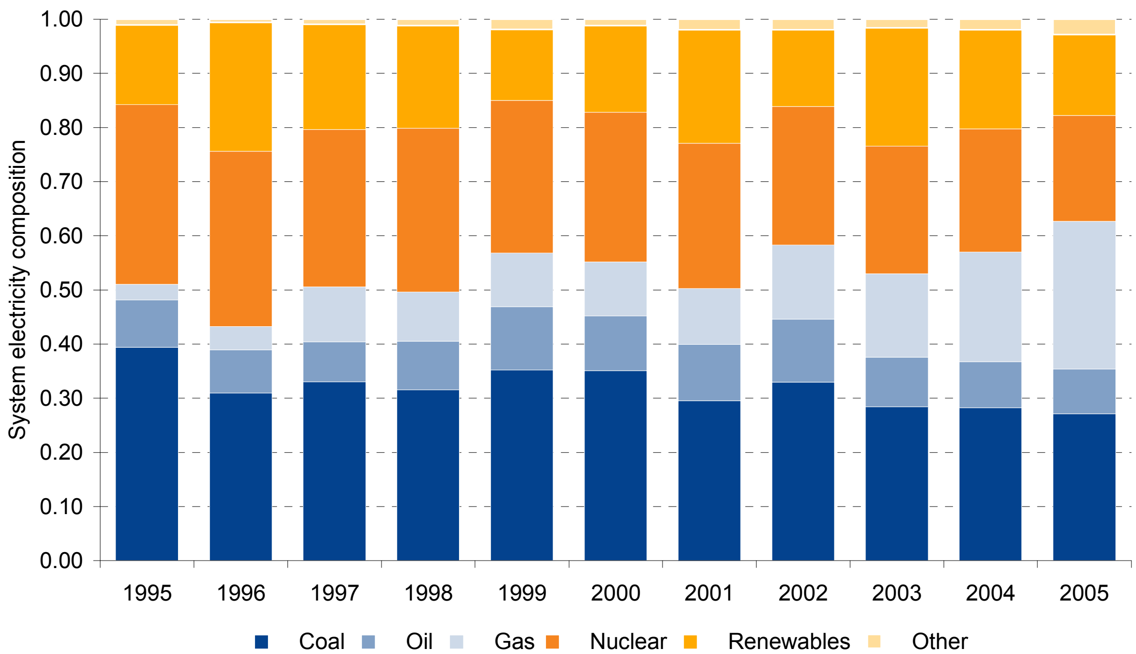
The diversity of Spain's electricity system, a proxy for its security of supply, increased over the period 2000 – 2005. This is evident from the increase in the Shannon Wiener index from 1.624 in 2000 to 1.755 in 2005, and corresponds to an improvement in the distribution among the different energy sources.

Figure 9 – Electricity system CO_2 emission trend, 1995 – 2005



Source: Pöyry Energy analysis based on IEA electricity data

Figure 10 – Electricity system generation composition, 1995 – 2005



Source: IEA

B.1.3 Administrative performance

OPTRES (2007) reports that the administrative barrier of Spain's FIT scheme is high, giving it a score of 4.2 out 5, where a score of 0 represents no perceived barrier and 5 represents the highest perceived barrier.

According to OPTRES (2007), Spain has fairly low financial and social barriers, which enhances the success of the FIT scheme – there are significant soft loans and investment incentives available, and a high level of social awareness and acceptance for RES-E technologies.

B.1.3.1 Estimated investor returns

Analysis using a discount rate of 6.6% gives estimates of the respective costs of onshore wind, solar PV, biomass, and hydroelectric RES-E as follows: 8.7, 45.7, 4.2, and 8.8 € cents/kWh (real 2008 money). This is against the following respective upper limits of remuneration: 9.5, 44.0, 18.1, and 9.1 € cents/kWh (real 2008 money). From this it is apparent that incentive for biomass is comparatively more generous compared to onshore wind, solar PV, and small hydro RES-E. However, higher capacity factor of wind turbines at the more attractive sites, for example, should improve the profitability. (In the analysis an average capacity factor of approximately 22% was assumed for wind in Spain).

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ANNEX C – PORTUGAL

C.1.1 Summary of scheme and history

Feed-in tariffs are the main RES-E support instrument in Portugal, and are complemented by investment incentives. The tariffs are non-market based (i.e. fixed) and are guaranteed for a period of 15 years. The tariff levels depend on numerous factors including:

- technology (i.e., tariffs are technology differentiated);
- local renewable energy resource (i.e., tariffs are stepped);
- time of electricity generation (peak/ off-peak) – (i.e., tariffs are demand oriented);
- avoided CO_2 emission and electricity losses;
- monthly inflations; and
- revision of the tariffs occurs on achievement of specific milestones, that is, when certain installed capacities of RES-E plants are reached: (e.g., Solar PV: 150MW, biomass: 150MW, Biogas: 50MW).

C.1.1.1 Tariff setting methodology

The formula for calculating the feed in tariff was established in the Decree-law 33-A of February 2005 and consists of the factors highlighted above:[63]

$$T_{m,i} = CL_m * \left[FC + VC + EC * Z_i\right] * \left[\frac{CPI_{m-1}}{CPI_{ref}}\right] * \left[\frac{1}{1-GL}\right]$$

Where:

m – considered month of operation

i – considered plant technology

$T_{m,i}$ – tariff applicable during month m to the electricity produced by the respective installation of technology i, using renewable resources for power generation

CL_m – coefficient considering the temporal profile of feed-in, the respective time intervals and coefficients are defined in the regulation.

FC – specific fixed costs of a new reference installation using fossil fuels that can be avoided by the respective renewable installation. A fixed value per generated kWh is applied over the entire runtime of the installation.

VC – specific variable costs of a new reference installation using fossil fuels that can be avoided by the respective renewable installation (a fixed value per generated kWh is applied over the entire runtime of the installation).

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63 Portugal Renewable Energy Policy Review, EREC, March 2009; Marlene Neves, Promotion of RES-E in Portugal, Portugal's Directorate for Energy and Geology, Presentation at the 6th Workshop of the International Feed-in Cooperation, November 3-4, 2008

EC – specific environmental costs (referring to CO_2 emissions) of a new reference installation using fossil fuels that can be avoided by the respective renewable installation (a fixed value per generated kWh is applied over the entire runtime of the installation).

Z – technology specific coefficient taking into account the individual properties of the renewable resource and the technology applied. It is multiplied by the respective environmental costs avoided EC_{Em}.

CPI_{m-1} – consumer price index relating to the month (m-1). The index is calculated for the Portuguese mainland and does not consider leasing costs.

CPI_{ref} – consumer price index relating to the month before the initial feed-in by the respective installation. The index is calculated for the Portuguese mainland and does not consider leasing costs.

GL – losses in the transmission and distribution grid that are avoided by the respective renewable installation. The regulation only differentiates between installations above or below 5 MW, respectively.

There is a separate minimum and maximum tariff (which acts effectively as a ceiling or floor) according to the variations of load on the grid.

C.1.2 Policy objectives performance

C.1.2.1 Increasing the deployment of renewables

Over the period 2000 – 2005, wind generating capacity in Portugal increased by 981MW (equivalent to 66.6% growth per annum), solid biomass generating capacity grew by 54MW (4.5% growth per annum), biogas power generating capacity grew by 7MW (51.6% growth per annum), and solar PV generating capacity rose by 1MW (14.9% growth per annum). The increase post–2005 has been even more significant, as of August 2008 wind capacity stood at 2672 MW.

C.1.2.2 Decarbonisation and emissions reductions

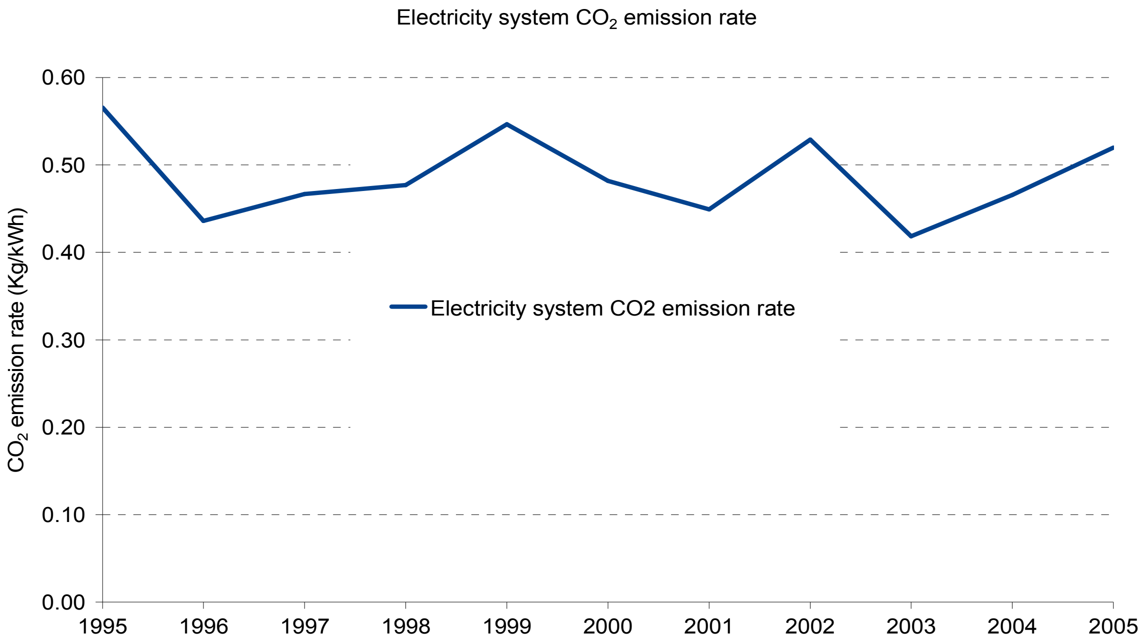
Portugal's electricity system CO_2 emission rate increased by approximately 38g/kWh over the period 2000 – 2005 (see Figure 11). This increase in emission rate arose due to the following changes in the composition of the system's electricity generation (see Figure 12): Coal (-0.7%), Oil (-0.4%), Gas (+12.7%), Renewables (-11.6%). Not only did renewable electricity decreased as a component of the system, but it also decreased in absolute terms from 13.13TWh in 2000 to 8.56TWh in 2005. This was mainly due to massive fluctuation in hydroelectric production from 11.7TWh to 5.1TWh.

Wind generation, on the other hand, increased significantly over the aforementioned period from approximately 0.2TWh (0.46% of system) to 1.8TWh (3.86% of system). Without this increase, the systems CO_2 emission rate would have increased by roughly a further 22g/kWh, assuming the electricity differential would be picked up equally between the fossil based technologies.

C.1.2.3 Improving security of supply

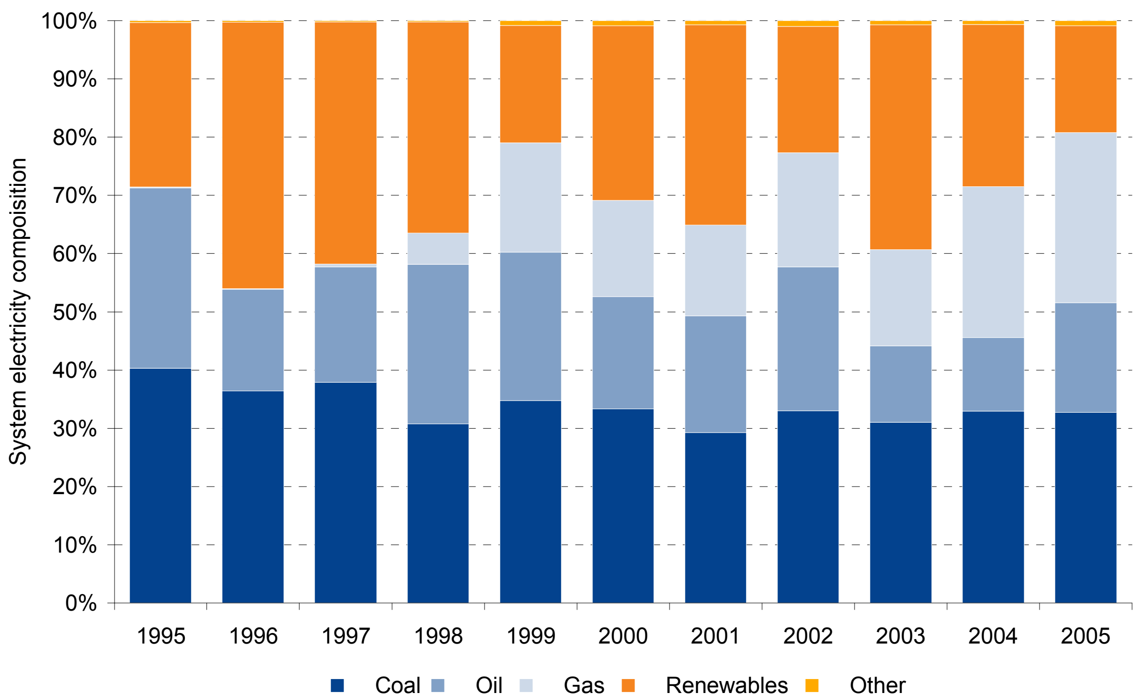
Despite the reduction in renewable energy component of the system and the consequent increase in the system CO_2 emission rate, the diversity of the system increased marginally over the period 2000 – 2005. This is due to the more evenly distribution of the system electricity generation in 2005 between the four main sources (coal, gas, oil, renewables). The Shannon Weiner index increased from 1.525 in 2000 to 1.582 in 2005.

Figure 11 – Electricity system CO_2 emission trend, 1995 – 2005



Source: Source: Pöyry Energy analysis based on IEA electricity data

Figure 12 – Electricity system generation composition, 1995 – 2005



Source: IEA

C.1.3 Administrative performance

The administrative barrier of Portugal's FIT scheme is very high, as the scheme is administratively complex and has low transparency – it is based on many factors, which are difficult to determine. This has led to high investors' uncertainty and low investment security. However, this is to an extent offset by the very low financial barrier associated with the scheme – according to OPTRES (2007), investment incentives of up to 40% are provided to RES-E projects. In general, Portugal's feed-in tariffs provide relatively high returns for RES-E investors, as outline earlier.

Overall, the scheme has only been able to achieve moderate performance for large scale RES-E projects deployment, while the exploitation of small scale generation is poor. The very high administrative barrier associated with the scheme is the main reason for this, which shows that implementing complex tariff systems may not be a good choice for designing a scheme to attract small scale RES-E plants.

C.1.3.1 Estimated investor returns

Analysis using a discount rate of 6.6% gives estimates of the respective costs of solar PV, biomass RES-E (the only two technologies supported in 2008 of the four we considered) as follows: 78.2 and 4.5 € cents/kWh (real 2008 money). This is against the following respective upper limits of remuneration: 25.0 and 8.0 € cents/kWh (2008 real money). From this it is apparent that biomass incentives are as estimated reasonably good. Onshore wind and hydro technologies were not supported under the FIT scheme in 2008; however, onshore wind was supported in 2006. Solar PV remuneration level under the FIT appears to be extremely small relative to the estimated cost of the technology to initiate deployment.

ANNEX D – CZECH REPUBLIC

D.1.1 Summary of scheme and history

Feed-in tariffs were instituted in the Czech Republic in 2002, and have since been supported by investment incentives. The scheme provides RES-E producers with a choice between fixed feed-in tariffs or premium feed-in tariffs (green bonuses). Higher overall remuneration levels are allowed for premium tariffs to reflect the higher business risk associated with this option. There is however a clear preference for the fixed tariffs at the moment, especially among small RES-E installations and investors. No choice is given for solid biomass co-firing installations for which only the premium tariff applies. The tariffs for solid biomass and biogas RES-E technology are differentiated according to their specific fuel type.

The tariffs, which are relatively high, are reviewed annually, and the support is guaranteed for a period of 20 years (30 years for small hydroelectric plants). There is a purchase obligation for the output from RES-E plants as well as a forecast obligation for installations above 1MW. However, wind and solar PV technologies are excluded from the forecast obligation. In the latest tariff revision in August 2008, degression was introduced in the scheme.

D.1.1.1 Tariff setting methodology

The feed-in tariff is calculated on the basis of a minimum price of electricity for a reference project – this is the price at which the net present value of the project is zero and is calculated as[64]:

$$NPV = \sum_{t=1}^{T_z} CF_t \cdot (1 + r_n)^{-t} = 0$$

Where:

CF_t – the difference between the revenue collected and costs paid in year *t* of the project (based on data from a reference project).

R_n – nominal discount rate (the Energy Regulatory office assumes a Weighted Cost of Capital (WACC) of 7%

T_z – project lifetime (for a reference project)

The FIT is assured during the lifetime of the plant with annual adjustments by PPI and tax exemptions for the first 5 years.

64 Benes, Knápek, Market value of electricity generated based on RES utilization, May 2007; Stanislav Travnicek, Status of national feed-in tariff system – Czech Republic, Czech Energy Regulatory Office, April 8, 2008

D.1.2 Policy objectives performance

D.1.2.1 Increasing the deployment of renewables

Over the period 2000 – 2005, wind power capacity in the Czech Republic increased by 28MW (equivalent to annual growth of 96.1%), solid biomass generating capacity increased by 1182MW, and biogas generating capacity increased by 36MW. There was no deployment of solar PV technology over the period.

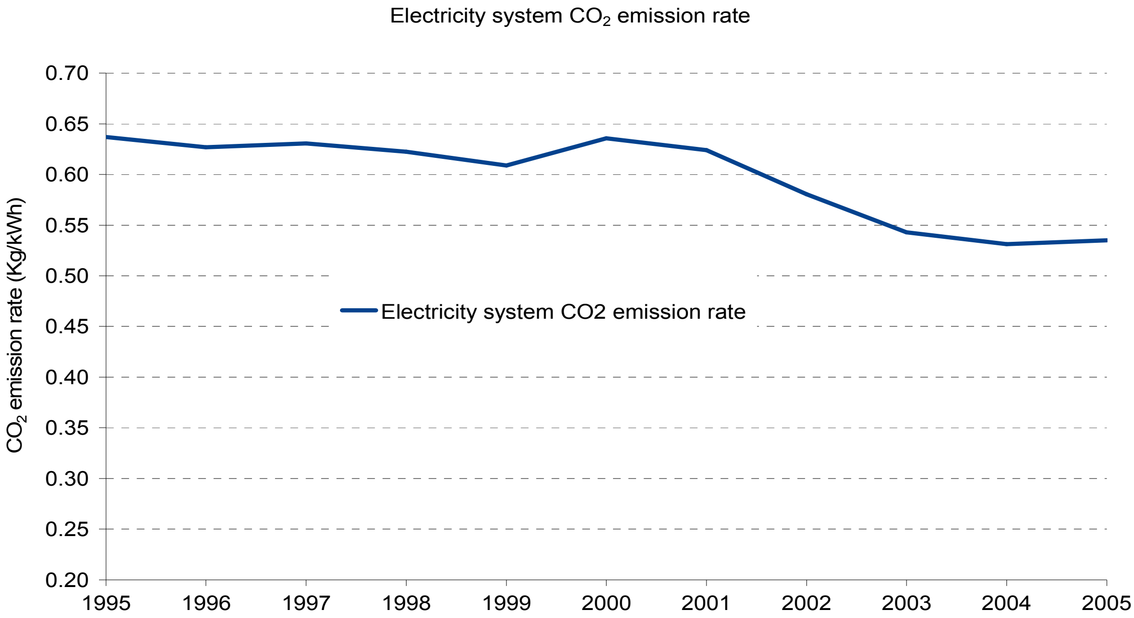
D.1.2.2 Decarbonisation and emissions reductions

The Czech Republic's electricity system CO_2 emission rate reduced by approximately 45g/KWh since the introduction of the FIT in 2002 to 2005 (see Figure 13) – averting roughly 11 million tonnes of CO_2 emission. The growth in RES-E generation only accounted for approximately 2.5% of the CO_2 emission reduction – the decarbonisation of the Czech's electricity system was mainly (97.5%) due to increase in nuclear generation.

D.1.2.3 Improving security of supply

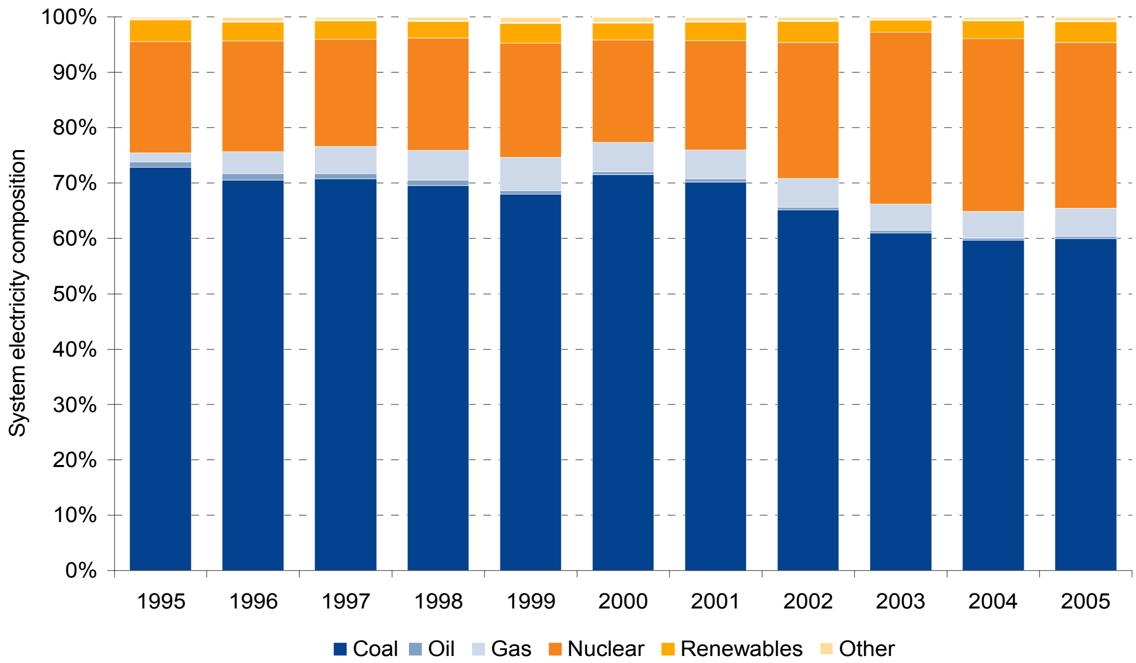
The diversity of the Czech's electricity system, a proxy for its security of supply, increased since the introduction of the FIT scheme. This is evident from the increase in the Shannon Wiener index from 0.984 in 2002 to 1.026 in 2005, and corresponds to a decreasing fossil fuel composition of the electricity system generation in contrast to an increasing nuclear generation composition (see Figure 14). The share of coal, gas, and oil based electricity generation as components of the system decreased by 5.2%, 0.1%, and 0.1% respectively, while nuclear generation increased by 5.4%, over the period 2002 – 2005. Electricity from renewable energy plants increased in absolute terms over the period, but decreased as a share of the system electricity generation composition.

Figure 13 – Electricity system CO_2 emission trend, 1995 – 2005



Source: Source: Pöyry Energy analysis based on IEA electricity data

Figure 14 – Electricity system generation composition, 1995 – 2005



Source: IEA

D.1.3 Administrative performance

OPTRES (2007) assesses the Czech Republic FIT scheme's administrative barrier to be high; giving it a score of 4.0 out of 5, where a score of 0 represents no perceived barrier and 5 represents the highest perceived barrier. OPTRES also deems the financial barrier to be high; giving it a score of 3.8 out of 5. This is due to the general lack of supplementary funding. This is due to the general lack of supplementary funding. The high financial and administrative barriers have limited the potential of the Czech's FIT scheme. However, all in all, the tariff is very generous and provides attractive returns, which is the scheme's main plus.

D.1.3.1 Estimated investor returns

Analysis using a discount rate of 6.6% gives estimates of the respective costs of onshore wind, solar PV, biomass, and hydroelectric RES-E as follows: 8.3, 68.6, 4.1, and 4.9 € cents/kWh (real 2008 money). This is against the following respective upper limits of remuneration: 14.0, 57.1, 18.2, and 12.1 € cents/kWh (real 2008 money). From this it is apparent that the incentives for onshore wind, biomass and small hydro are reasonably attractive, in contrast to Solar PV technology.

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ANNEX E – DENMARK

E.1.1 Summary of scheme and history

Feed-in tariffs are the main RES-E support mechanism in Denmark. The Danish government implements premium feed-in tariffs for onshore wind, a tendering regime including individual negotiated fixed feed-in tariffs for a restricted amount of offshore wind production, electricity tax exemptions for household solar PV production, and fixed feed-in tariffs for all other RES-E technologies supported.

The FIT policy framework varies from 10 to 20 years depending on the technology and the scheme applied, and the tariffs are revised on an ad hoc basis. The current tariffs, which are generally low compared to the formerly generous feed-in tariffs, are differentiated by technology, scale, and local conditions.

The scheme provides purchase obligations on the network operators without any forecast obligation for the RES-E producers. Extra incentives are provided for decommissioning and repowering wind turbines.

E.1.2 Policy objectives performance

The IEA (2008) reports that Denmark has been among the world leaders in wind and solid biomass RES-E exploitation during the period 2000 – 2005, relative to realizable potential.

E.1.2.1 Increasing the deployment of renewables

Over the period 2000 – 2005, wind power capacity in Denmark grew by 737MW, solid biomass generating capacity increased by 498MW, biogas generating capacity increased by 24MW, and solar PV capacity rose by 2MW. This equates to equivalent annual growth rates of 5.5%, 46.7%, 9.7% and 24.6% respectively.

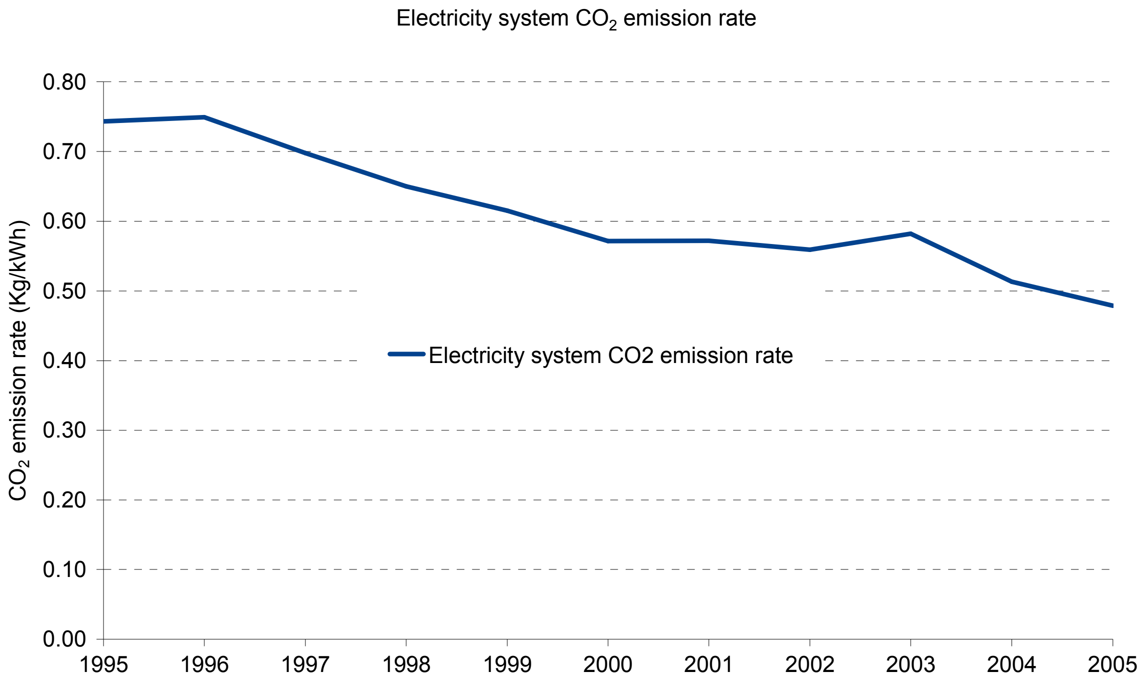
E.1.2.2 Decarbonisation and emissions reductions

Denmark's electricity system CO_2 emission rate reduced by approximately 93g/KWh over the period 2000 to 2005 (see Figure 15) – averting roughly 5.71 million tonnes of CO_2 emission. The growth in RES-E generation accounted for the entire reduction.

E.1.2.3 Improving security of supply

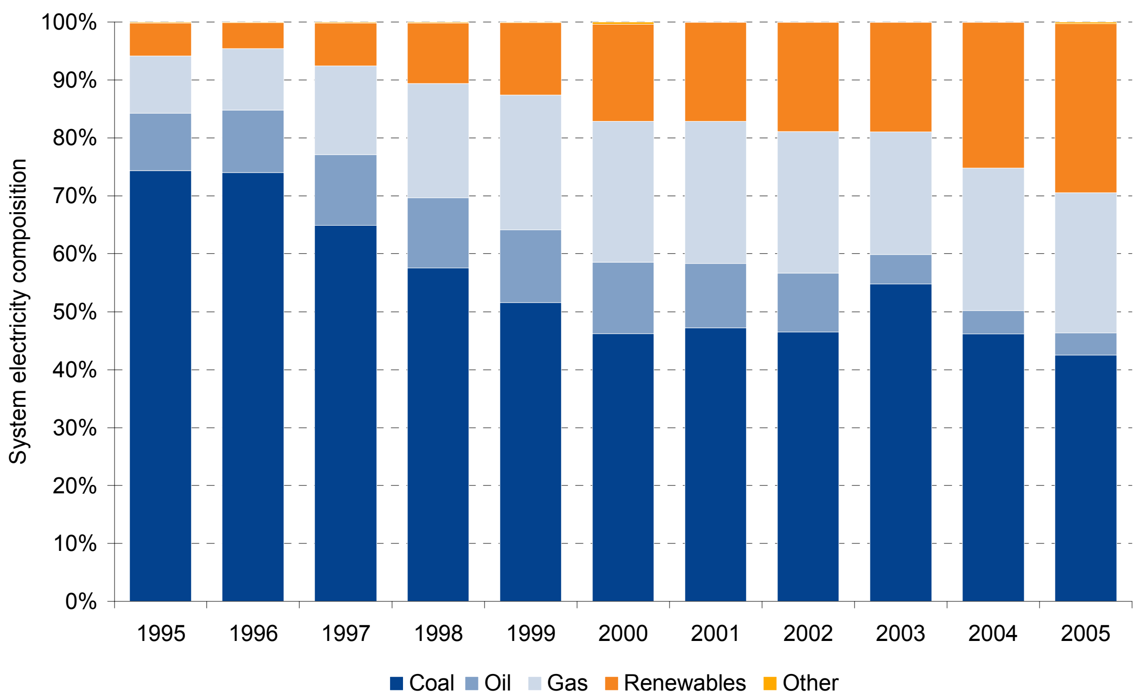
The diversity of Denmark's electricity system, a proxy for its security of supply, increased during the period 2000 – 2005. This is evident from the increase in the Shannon Wiener index from 1.385 in 2000 to 1.403 in 2005, and corresponds to a decreasing fossil fuel composition of the electricity system generation in contrast to an increasing RES-E composition (see Figure 16). The share of coal, gas, and oil based electricity generation as components of the system decreased by 3.7%, 8.5%, and 0.1% respectively, while RES-E generation increased by 12.5%, over the period 2000 – 2005.

Figure 15 – Electricity system CO_2 emission trend, 1995 – 2005



Source: Source: Pöyry Energy analysis based on IEA electricity data

Figure 16 – Electricity system generation composition, 1995 – 2005



Source: IEA

E.1.3 Administrative performance

OPTRES (2007) assesses Denmark FIT scheme's administrative barrier to be medium; giving it a score of 3.0 out of 5, where a score of 0 represents no perceived barrier and 5 represents the highest perceived barrier.

High and stable feed-in tariffs have contributed to historical success of the FIT scheme. In recent times, the rebalance of the generosity of the scheme have led to significant drop off in RES-E deployment rates.

In general, the Danish FIT scheme is administratively simple and very transparent. The IEA 2008 report observes that a key factor which led to the high growth in solid biomass deployment in Denmark was the availability of abundant biomass combined with the opportunity for co-firing in coal-fired boilers.

E.1.3.1 Estimated investor returns

Analysis using a discount rate of 6.6% gives estimates of the respective costs of solar PV and biomass RES-E (the only two technologies supported in 2008 of the four we considered) as follows: 78.2 and 4.5 € cents/kWh (real 2008 money). This is against the following respective upper limits of remuneration: 25.0 and 8.0 € cents/kWh (real 2008 money). From this it is apparent that incentive for biomass allows profitability at this discount rate. Onshore wind and hydro technologies were not supported under the FIT scheme in 2008; however, onshore wind was supported in 2006.

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ANNEX F – NETHERLANDS

F.1.1 Summary of scheme and history

Prior to 2000, the main support scheme involved a quota obligation system with tradable green certificates (TGC). In 2003, the Netherlands instituted a new premium feed in tariff system (MEP). Under the new scheme, Dutch producers of renewable electricity feeding into the public grid received a fixed fee per kWh for a guaranteed period of ten years. Since its introduction, the FIT scheme has been complemented by fiscal investment incentives and, prior to 2005, by energy tax exemptions.

Following the end of the MEP and CHP subsidy schemes in August 2006, the government launched a renewables support mechanism (SDE) starting from April 2008. The SDE is a 'sliding premium' scheme where the level of premium is based on the average electricity price – the premium is decreased (increased) linearly with increasing (decreasing) electricity price.

The SDE is financed from the treasury and is characterised by a capped total budget. The scheme involves separate subsidy budgets for each technology and an approximate level of deployment anticipated given the funding – for 2008-2011, for instance, budgeted onshore wind deployment is approximately 2000MW, 450MW for off-shore wind, and 70-90MW for solar. Investors are expected to tender for projects, although in the first year, funding is available on a first come first served basis.[65]

F.1.2 Policy objectives performance

According to the IEA (2008), the Netherlands is a world leader in solid biomass RES-E exploitation and, most recently, has become among the most effective countries in wind and solar PV deployment, relative to realizable potential.

F.1.2.1 Increasing the deployment of renewables

Figure 17 shows the growth in RES-E deployment (excluding large scale hydro) in the Netherlands over the period 2003 to 2005, which gives an indication of the feed-in tariff policy effectiveness. Within two years of introducing the FIT scheme, wind power capacity in the Netherlands grew by 318MW (an equivalent annual growth of 16.2%), solid biomass generating capacity increased by 183MW (or 46.4% per annum), and solar PV capacity rose by 5MW (an annual growth of 5.3%).

F.1.2.2 Decarbonisation and emissions reductions

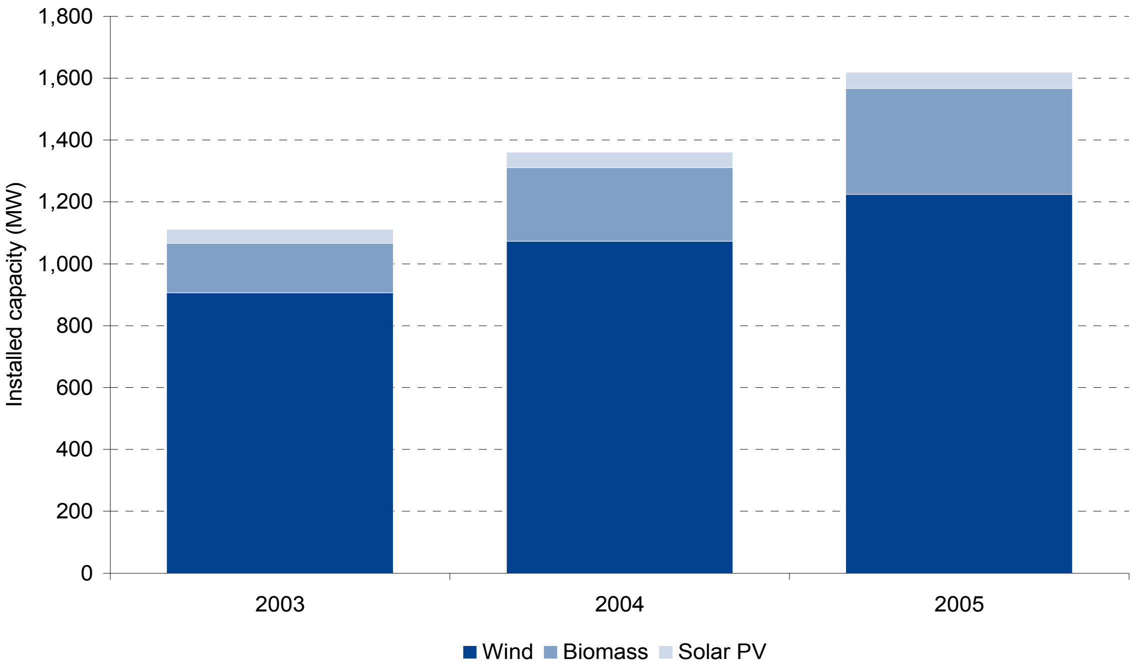
The Dutch electricity system CO_2 emission rate reduced by approximately 23g/KWh over the period 2003 to 2005 (see Figure 18) – averting roughly 3.5 million tonnes of CO_2 emission. The growth in RES-E generation accounted almost entirely (approx. 99%) for this reduction.

65 Ron van Erck, Development of Renewable electricity towards 2020 – Dutch perspective, Ministry of Economic Affairs Energy & Sustainability, April 2008

F.1.2.3 Improving security of supply

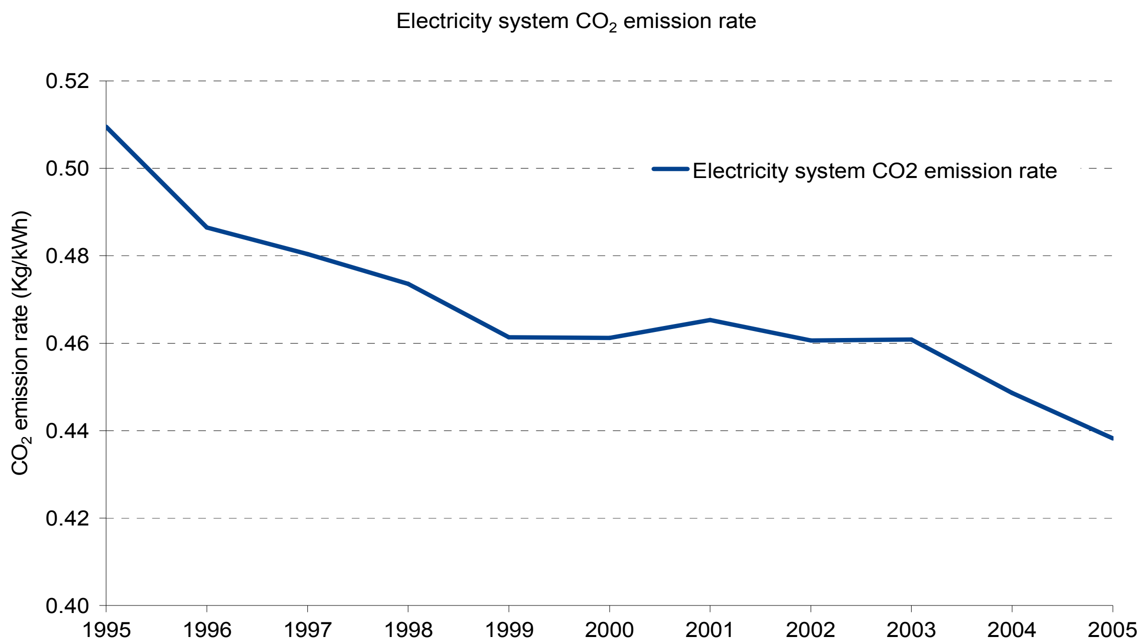
The diversity of the Dutch's electricity system, a proxy for its security of supply, also increased since the introduction of the FIT scheme. This is evident from the increase in the Shannon Wiener index from 1.090 in 2003 to 1.141 in 2005, and corresponds to a decreasing fossil fuel composition of the electricity system generation in contrast to an increasing RES-E composition (see Figure 19). The share of coal, gas, and oil based electricity generation as components of the system fell by 1.7%, 0.7%, and 0.86% respectively, while RES-E generation grew by 3.39%, over the period 2003 – 2005.

Figure 17 – RES-E installed capacity trend, 2003 – 2005 excluding large hydro



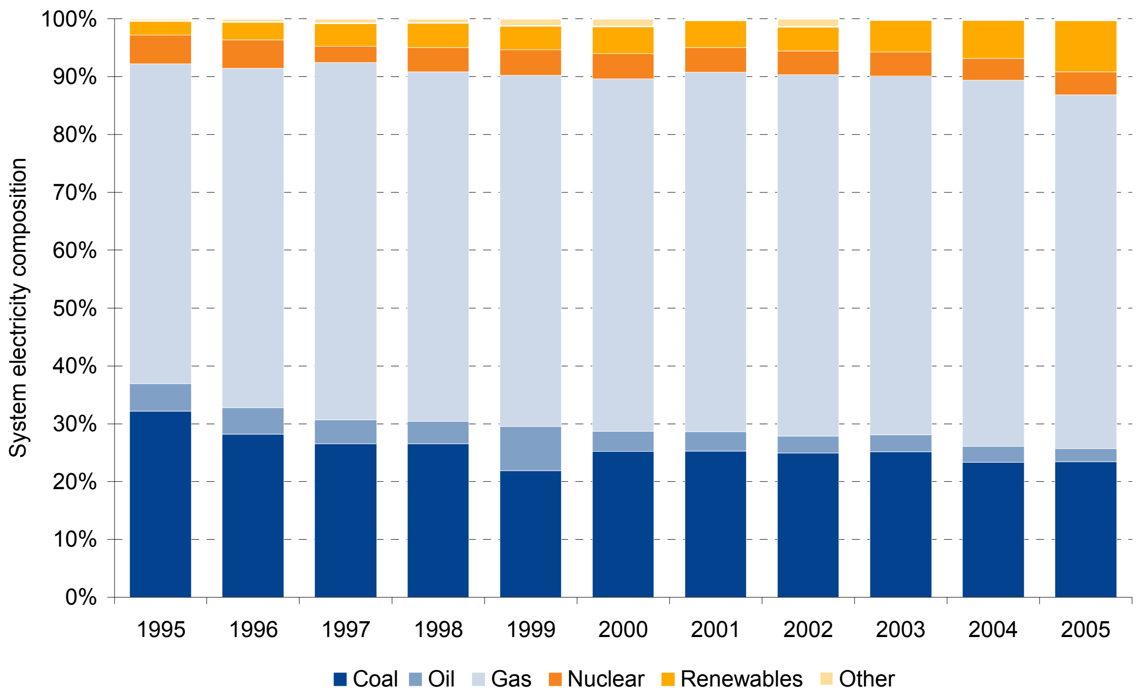
Source: Source: IEA

Figure 18 – Electricity system CO_2 emission trend, 1995 – 2005



Source: Source: Pöyry Energy analysis based on IEA electricity data

Figure 19 – Electricity system generation composition, 1995 – 2005



Source: Source: IEA

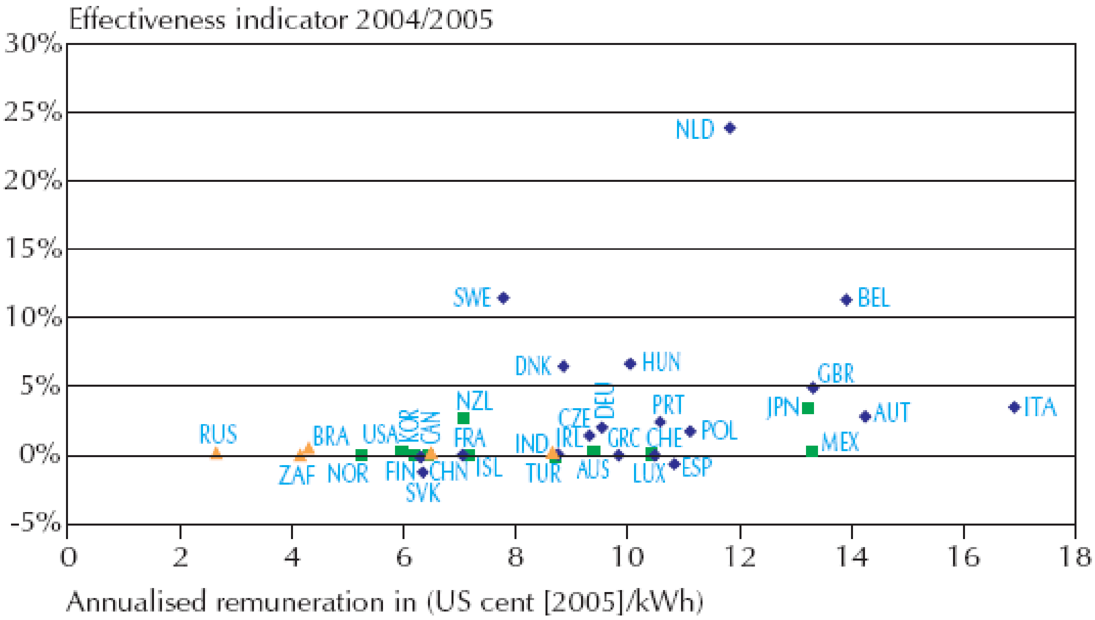
F.1.3 Administrative performance

OPTRES (2007) assesses the Netherlands FIT scheme's administrative barrier to be medium; giving it a score of 2.8 out of 5, where a score of 0 represents no perceived barrier and 5 represents the highest perceived barrier.

A new 'sliding premium' feature, introduced in 2008, should add to the administrative complexity of the FIT scheme. However, the feature should minimise the risk of overspending from the government's perspective and the risk of under compensation from the investors' point of view, since the premium is adjusted based on average electricity prices. This should result in the reduction of the cost of the FIT policy, in addition to the increase in certainty to investors, consequently reducing their hurdle rates.

Figure 20 (adopted from IEA (2008), highlights that the Netherlands was the most effective country in terms of solid biomass deployment, relative to realizable potential, over the period 2004/2005. At the end of 2005, the Netherlands had 2246MW of installed solid biomass RES-E generating capacity. A key factor which led to the high growth in solid biomass deployment in the Netherlands was the availability of abundant biomass combined with the opportunity for co-firing in coal-fired boilers.

Figure 20 – Solid biomass electricity: Policy effectiveness versus annualised remuneration levels



Source: Deploying Renewables: Principles for Effective Policy, IEA, 2008

F.1.3.1 Estimated investor returns

Analysis using a discount rate of 6.6% give estimates of the costs of biomass RES-E, which was the only technology supported in 2008 of the four we considered, to be 4.4 € cents/kWh (real 2008 money). This is against an upper limit of remuneration of 14.7 € cents/kWh (real 2008 money). From this it is apparent that there are ample incentives for biomass deployment.

ANNEX G – INVESTOR ATTITUDES

This Annex sets out the results our analysis of commercial investor behaviour including estimates of investor's cost of capital.

G.1.1 Characterising the investor types

We have considered different investor types in our analysis that may be active in the sub 5MW renewable space as described below. We entered into discussions with representative organisations in each of the categories identified below.

G.1.1.1 Commercial developers

These companies will be developing projects at the larger end of the spectrum, perhaps in the 1MW to 5MW range. Examples would include RES and Wind Direct a subsidiary of Wind Prospect. RES is owned by the construction and civil engineering company McAlpine whereas Wind Prospect is funded by Hg Capital, a private equity firm.

G.1.1.2 Pension funds

Larger pension funds have invested more directly in renewable projects in some situations. A relatively certain incentive mechanism acts in a similar way to an annuity and so may be attractive to these investors. Alternatively they may continue to invest through private equity or other vehicles. The investments could be through shareholdings in listed companies specialised in the area or as above through specific development companies.

G.1.1.3 Project finance banks

In order to secure better equity returns developers may wish to access long-term debt to leverage their investment. Typically, the larger banks are not interested in sub 20MW scale due to economies of scale. Triodos and The Cooperative Bank do operate in the sub-5MW space. As the market grows we may see more banks specialising in the area, or aggregation of separate projects into more easily financeable packages.

In general lending banks will focus on ability of a project to repay the debt under a range of possible circumstances. The debt may be sized according to low cashflow scenarios. This will impact on the amount of leverage available and will therefore influence the level of equity returns that are possible.

G.1.1.4 Utilities

Utilities could invest in the sector in a number of ways and they will be important in facilitating the smaller end of the market. They may invest directly in larger projects (for example SSE investing in small hydro projects e.g. 2MW) or offer energy service company (ESCO) options to their smaller customers (down to domestic), whereby they effectively invest in the renewable generation asset on behalf of the customer and the customer hands back the value of the incentive.

A customer may agree to have solar PV panels fitted and lock in a 10-year fixed price deal with a utility for its electricity needs. Alternatively, customers could rent roof space to the utility. Finding a business model that works with the new incentive mechanism will take time.

It is interesting to note that all the major utilities in the GB market (British Gas (Centrica), EDF, E.ON, SSE, Scottish Power, Npower (RWE), Centrica, Ecotricity, Green Energy, and Good Energy) offer a fixed buy back or export tariff for domestic customers. However there are significant variations in tariffs offered particularly in technology capacity limits (5 – 100kW); eligible technologies (solar and wind predominantly); tariff levels (from 4.50 – 28 per kWh); treatment of ROCs. There are also differences in whether customers retain entitlement to ROCs; and installation and payment for meters – some suppliers install and pay for the cost of the meter, others arrange for installation if required but charge the customer, while others require customers to install and pay for their own. Given the complexities of the renewable obligation scheme it could be argued that such offers are hampered by administrative costs.

Distribution companies will need to increase investments plans under a successful small scale renewable scheme and these companies will need to be able to make an appropriate return on these investments.

G.1.1.5 Communities / cooperatives

Communities may wish to get involved in some larger projects. One way that this is happening at present is through not-for-profit cooperatives such as Energy4All with projects at the 2MW scale.

The model employed is to work with landowners to find suitable sites for wind turbines. Each project raises capital through a share offering, marketed toward local communities but open to all. Investors then receive a regular dividend based on the financial results of the project.

If this is seen as a key route to investment by policymakers then ways to facilitate and encourage the development of cooperatives should be considered given the absence of a profit incentive as a growth driver.

G.1.1.6 Industrial companies and famers

Our understanding is that in general, industry and farmers work with developers or cooperatives rather than investing directly in renewable assets as a non-core business activity. If a simpler and more stable set of arrangements is offered then perhaps this will change.

It is not just wind turbines that are of interest in this arena, anaerobic digestion (AD) of farm wastes is one area which could see some significant growth.

G.1.2 Rates of return sought by investors

The cost of capital that investors are subject to is an important cost element that feeds into the estimation the 'correct' level of support that should be given via a feed-in tariff mechanism. Below we estimate the cost of capital of the different investor types by technology and (broad) scheme design.

This is difficult to do for a number of reasons. We don't know the detail of the final design of the scheme and this will have a bearing on the risks borne by the investor. New technologies are included which have a limited track record. The financial market crisis means that current data may not be appropriate for setting longer-term tariffs.

The classic approach employed widely is to use the capital asset pricing model (CAPM) to estimate a firm's weighted average cost of capital (WACC). But as we are looking to estimate a cost of capital by technology and mechanism design this proves less useful as comparable companies are unlikely to exist in sufficient numbers, if at all, to provide reliable data points to feed into the CAPM model.

Other approaches have been used to estimate technology specific hurdle rates (which may differ from a firm's cost of capital to reflect technology specific risks) but rely on a large number of assumptions rather than verifiable data.

We have sought a more practical approach bearing in mind the uncertainty which surrounds these estimates, especially in the current climate, and the purpose of the study in exploring the impact of different feed-in tariff schemes.

By discussing the issues with different investor types and by referencing established approaches and sources of data and experience from other feed-in schemes we have derived the following set of assumptions.

Table 27 – Fixed Feed-in Tariff Discount Rates (post-tax nominal project)

	Utility / ESCO		**Developer**
	Large scale	Small scale	Large scale
Solar PV	8%	12%	10%
Onshore Wind	8%	12%	10%
Hydro	8%		10%
Biomass	10%	12%	12%
Wave	12%		14%
Tidal	12%		14%
Waste AD	8%	10%	10%
Waste Gasification	12%		14%
Waste Incineration	8%		10%

Source: Pöyry Energy Consulting

Table 28 – Premium Feed-in Tariff Discount Rates (post-tax nominal project)

	Utility / ESCO		Developer
	Large scale	Small scale	Large scale
Solar PV	9%	13%	12%
Onshore Wind	9%	13%	12%
Hydro	9%		12%
Biomass	11%	13%	14%
Wave	13%		16%
Tidal	13%		16%
Waste AD	9%	11%	12%
Waste Gasification	13%		16%
Waste Incineration	9%		12%

Source: Pöyry Energy Consulting

G.1.3 Published WACC Estimates

In regulating network business in the UK Ofgem defines an appropriate return on investments based on estimates of the companies' WACC. In the latest price control the real post-tax return on investment is 4.4% (6.5% nominal post-tax assuming 2% inflation). This is seen as appropriate return for a stable regulated business dealing with tried and tested technology. In Ireland the equivalent assumption is 4.92% real post-tax.

In Ireland before the single market for electricity was created the Irish best new entrant calculation was used to determine top up energy prices in the imbalance market. The best new entrant figure was supposed to represent the price at which a CCGT developer would be incentivised to enter the market. As well as estimates for capital costs of CCGT the Irish regulator estimated the appropriate rate of return. In 2007, the last year the calculation was carried out, the best new entrant formulae used a real pre-tax WACC of 7.83% assuming 70% gearing of the project.

In Ireland in the new market arrangements the capacity payment mechanism requires estimation of the WACC of an investor in peaking plant. In September 2008 the value was calculated for 2009 as real pre-tax 7.07% for the Republic and 8.07% for the North. The assumption behind the new entrant peaker figure is that it has a relatively stable income stream as the capacity payment mechanism ensures that revenues are delivered. In practice, the year-on-year revision of the figure, together with other factors increase the risk associated with the peaker investment.

With the changes in the market in the UK since September, with a lower risk free rate but higher debt spreads the 8.07% figure could be increased by 1 to 1.3%.

We surmise from the above that a fully regulated investment facing little risk a nominal post-tax WACC of 6%-7% is deemed appropriate and that more uncertain investments in generation assets a WACC of 8%-9% nominal post-tax is deemed appropriate by regulatory authorities.

In other confidential studies on generator WACCs we have calculated differences of roughly 3% in WACCs between fully contracted generation companies and those facing full market price risk. In assessing the difference between a fixed feed-in tariff and a premium based tariff we would suggest that part of the 3% difference would be appropriate. Depending on what level the premium is set a different level of market risk will be seen by the project. In the tables above we have assumed a one percent uplift between a fixed feed-in scheme and a premium based scheme to reflect this degree of extra market risk.

G.1.4 Estimates for discount rates under feed-in tariff regimes

We have distinguished between two types of investor, a utility or ESCO type of investor and a developer. We have also developed discount rate estimates for two scales of project, large and small scale. This is to reflect the utility potential to develop large projects in the 1-5MW range and also to invest on behalf of commercial and domestic customers.

Our base assumption for a proven technology under a fixed feed-in tariff regime is 8% nominal post-tax.

We assume that a pure project developer would have a higher discount rate than a utility investor, even in a world of a fixed feed in tariff, as their WACC is likely to be higher. We increase all discount rates by two percentage points in the fixed feed-in tariff assumptions and by three percentage points under the premium arrangements as they will face more significant price risk than a vertically integrated utility.

As discussed above we increase rates by 1% to reflect the higher level of market risk under a premium based scheme.

We also vary the discount rates by technology to reflect the increased risks with less proven technologies. The variations are based upon experience gained through involvement of a small number of financings of projects using new and novel renewable technologies.

The increased discount rates under the small scale utility/ESCO developments reflects potential problems with counterparty credit risk that may be experienced with customers defaulting on arrangements and issues around ownership and control of assets. This is a difficult area to assess and these figures should be viewed as speculative.

In small scale wind we consider the discount rates to be applicable for wind turbines greater than 10kW as smaller scale micro turbines are viewed as unreliable and there is currently limited appetite among companies to become involved in micro turbines. Given the technology risk these may face higher discount rates than those stated here.

G.1.5 Current financial situation

Given the recent financial crisis it seems reasonable to ask whether the feed-in tariff should be designed to reflect the current financial situation.

In general the crisis means that investment is seeing something of a hiatus at the large energy infrastructure scale (>20MW), especially where smaller independent developers are involved, as project finance is more difficult to arrange.

Whilst spot base interest rates have been reduced, the cost of borrowing has not necessarily fallen. Debt spreads have increased so that corporate and project finance borrowing rates have perhaps increased slightly from pre-crisis levels (depending on the riskiness of the borrower). And longer-term interest rates have not fallen by as much as spot rates. At the time of writing quantitative easing is being employed in a bid to increase the level of lending and this may impact on the debt spreads in time.

It is not clear that the crisis will lead to a hiatus in investment at the smaller end of the scale (sub 5MW), however. Evidence from the Czech Republic suggests that the financial crisis has had a beneficial impact on renewable uptake as investors, faced with much lower savings rates, view the return on investment offered by the renewable incentive scheme as an attractive alternative.

At the same time an increased risk to developers, utilities and lenders working with industrial, commercial and domestic partners will be counterparty credit risk. How viable is the industrial company at which an investment will be made in the current climate? Will my domestic customer default on their bill? This may lead to increased discount rates and a shortening of the period over which the investment is considered. Whilst this credit risk is not new, the current climate may increase the level of risk associated with default.

A second-order effect from the global slowdown is on the cost of equipment. Over the past two years capital costs have increased at unprecedented levels, with doublings in some sectors. The expectation is for a major correction in the cost of equipment and whilst this will take time to feed through, evidence is beginning to be seen of a reduction occurring. Cycles in equipment costs can be expected to be seen into the future.

It would be best then to design the feed-in tariff bearing in mind the current situation but allowing for an early stage review and then regular periodic reviews thereafter to cope with changes in the wider economy.

G.1.6 Initial feedback from parties on design

In general companies were at the early stages of their thinking with regard to the design of the feed-in tariff and we did not set out to canvass opinion in a formal interview. Below are some of the key issues that appeared during our conversations. Naturally different actors had different views and so the following should not be seen as a consensus view, rather some interesting observations made by different parties.

There was concern that the objectives of the scheme should be clear. If industrial policy were one aim then it should be recognised that we were too late to build a capability in already established technologies and the focus should therefore be wave and tidal. Another concern was over the relatively high carbon abatement cost of some technologies when compared to alternatives.

In general banding by technology and size was thought to be a good idea. Suggestions of tariffs banded by production were common. In this situation the first X MWh of generation receive a high tariff, with blocks of falling tariff levels for volumes of generation thereafter. This results in smoother transitions between scales of generation. It was suggested that the tariff should be at or below the level of RO support once it reached larger capacity levels.

It was not clear to all parties that a fixed tariff was necessarily better even at the domestic level. It was felt by one party that whilst a fixed tariff was easier to consider from a purely financial perspective, a premium tariff offered intangible benefits for the customer in terms of how they would think about the potential benefits of generating their own electricity. This may reflect experience from the current situation where the economics are not always the main driver of investment.

In addition it was felt the renewable heat incentive would have to be a premium based scheme by its nature and that consistency between heat and electricity measures would be helpful for smaller customers' understanding.

It was argued that current charging arrangements did not reflect the true split of fixed and variable cost elements in customers' bills and that this may need to be addressed to ensure efficient investment decisions.

There was also concern over the timing of the introduction of the scheme and the changes that may be required. As a result an interim solution could be a premium scheme whilst offers and settlement systems were put in place. Perhaps other mechanisms that are already in place could be used if necessary to avoid the time required for any legislation.

There is a wider question here about the design of the scheme and its impact on metering and settlement requirements and we would suggest further analysis into this issue is required. This may be a particular issue for developers working with industrials at present whereby the arrangements are structured around on-site supplies of electricity in addition to general metering issues around export only or full value tariffs.

There was concern expressed that capitalisation of the scheme would lead to greater levels of bureaucracy to avoid fraudulent claims and that this could be counter-productive. Deeming was felt to be appropriate only at a small scale (i.e. domestic) and only for a short period of time.

The question of which areas would it be best to socialise costs was explored. Is the consumer/taxpayer better placed to take on market price risk, generation volume risk or credit risk (or some combination), for instance generation volume risk may reduce overall by appropriate aggregation.

As stated above these comments do not reflect the views of all parties contacted.

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