Det Energipolitiske Udvalg 2009-10
EPU alm. del Bilag 128
Offentligt

elementenergy

Design of Feed-in Tariffs for Sub-5MW Electricity in Great Britain

Quantitative analysis for DECC

Final Report

July 2009

URN 09D/704

Element Energy Limited
60 Newman Street
London
W1T 3DA
Tel: 020 7462 5299
Fax: 020 7323 4546

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1 Executive Summary

The EU Renewable Energy Directive sets the UK an ambitious target of meeting 15% of its final energy consumption using renewable energy sources by 2020. In conjunction with a large increase in the use of renewable heat and, to a lesser extent, renewable transport fuels, renewable electricity is expected to make a major contribution to the achievement of this target. Recent changes to the Renewables Obligation (RO) are predicted to deliver large amounts of renewable electricity from large-scale technologies, such as onshore and offshore wind. However, the banding of support within the RO does not provide sufficient incentives to small-scale renewable generators to encourage widespread uptake. For this reason, in the Energy Act 2008 the Government took powers to introduce a Feed-in Tariff for renewable electricity technologies up to $5MW_e$ in size and gas CHP systems up to $50kW_e$. Element Energy and Pöyry Energy Consulting were contracted by the Department of Energy and Climate Change to conduct a detailed review and analysis of the options for designing a Feed-in Tariff for Great Britain.

Methodology

The modelling approach is based on the construction of renewable electricity supply curves showing the size of the resource available at a given generating cost, as shown in Figure 1. The resource potentials for each technology were estimated using a combination of industry consultation, literature review and primary analysis using Geographical Information Systems (GIS). The resource potentials were combined with a technology cost and performance model, and a representation of investor behaviour based on telephone discussions with renewable energy investors. The resulting model is able to project uptake of each renewable technology under a wide range of feed-in tariff designs.

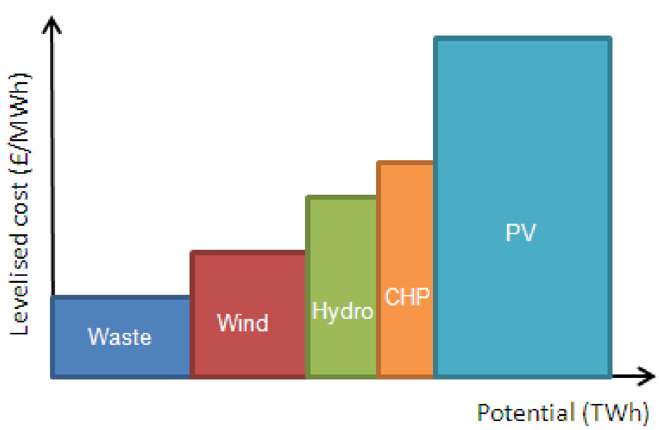

Figure 1 Illustrative renewable energy supply curve

Following discussions with DECC, the following technologies were considered in the model:

- Photovoltaics
- Onshore wind
- Hydroelectric power
- Wave power
- Tidal power
- Biomass CHP
- Waste to energy technologies
- Gas-fired CHP

Sewage gas and landfill have been deployed on a large scale under the Renewables Obligation. For the purposes of the modelling, it is assumed that these two technologies continue to receive support under the RO and are not supported under the FIT. In the main scenarios investigated, it is assumed that biomass electricity installations that do not make use of waste heat are not supported under the Feed-in Tariff. The interactions between the FIT and the Renewable Heat Incentive are discussed in the Analysis.

A representation of large-scale investor behaviour was developed based on telephone discussions with renewable energy investors. Investors are assumed to have technology-specific hurdle rates that they use when assessing the financial case investing in renewable technologies[1]. These hurdle rates vary from 8% for utilities investing in established technologies such as large wind turbines, to 14% for commercial developers investing in novel technologies such as Advanced Thermal Treatment of waste. To reflect the range of hurdle rates observed among investors in the real world, a distribution of hurdle rates was assumed, with early adopters requiring only 8% returns for all technologies before investing. Small-scale investors, such as householders and commercial building owners, are assumed to have a wider range of hurdle rates, which is consistent with the literature on energy efficiency purchases. For example, householders have a minimum hurdle rate of 3%, close to the social discount rate, and a maximum rate of 20%.

Assessment of the potential for sub-5MW electricity

The total technical resource was estimated for each of the technologies considered in the model. The technical potential represents the upper bound for the amount of a technology that can be deployed if sufficient policy and financial support were provided. The technical

[1] An investor's hurdle rate is the minimum financial return they would require from a project in order to invest in it.

potential does not include time-dependent constraints such as the maximum growth rate of the industry or a limit on consumer demand in a given year; these constraints are imposed on the absolute supply curves to give dynamic supply curves, which show the resource available in a given year.

Barriers are implemented at several points in the model. These dictate the level of deployment in a given year, and are caused by both market and social constraints. The market constraint is based on the ability of an industry to supply a demand for renewable energy technologies. The social barriers represent the social acceptance of renewable technologies changing as more are deployed. For example, it is assumed that social acceptance of wind-power decreases with increasing deployment as impacts from multiple developments begin to accumulate. Finally, an overall market growth constraint is applied to each technology, which limits the year on year growth of the industry. This is particularly important in the early years of the policy, where industries must grow rapidly from a small initial size.

Baseline

In order to assess the impacts of the Feed-in tariff scenarios, a baseline was established that projected uptake of sub-5MW technologies under Business as Usual. The baseline assumes that the banded RO continues to be the primary support measure for all technologies. Figure 2 shows the uptake from sub-5MW technologies in the baseline. Over 2TWh of electricity is generated from new installations in 2020, and the generation is provided exclusively by large-scale technologies such as on-shore wind, hydro and waste.

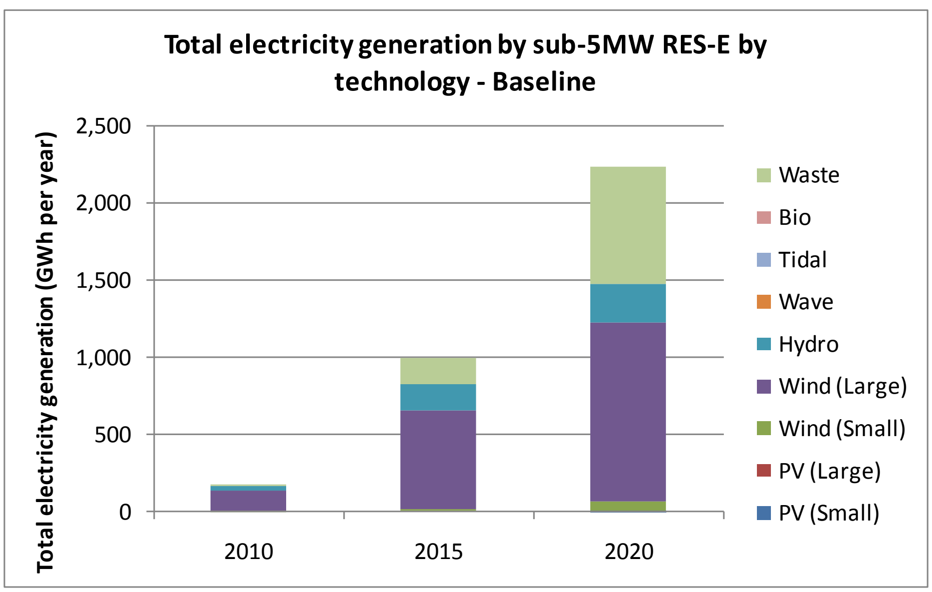

Figure 2 Electricity generation from sub-5MW technologies in the baseline

Policy results

The design of the Feed-in Tariff and the support levels paid to different technologies is guided by the overall aims for the policy. A scheme designed to meet a specific electricity generation target at the lowest cost to consumers and the economy will deliver a technology mix that is very different from a scheme designed to drive uptake of domestic – and community-scale installations. To allow easier comparison between scenarios, a total electricity generation target for 2020 was set so that the overall technology deployment was constant between runs. Following discussions with DECC, two targets were used in the modelling, corresponding to 2% and 3.5% of UK electricity. This is equivalent to 8TWh and 13.5TWh based on DECC's projection of UK electricity demand in 2020. Figure 3 shows the technology mix for a flat tariff of £155/MWh. This tariff level is the minimum tariff required to provide 8TWh of generation in 2020. In other words, it is equal to the generating cost of the most expensive technology required to meet the target. This tariff is paid to all renewable generators, and includes the market electricity price. It is assumed to stay constant throughout the policy to 2020. Although the total deployment in this scenario is significantly larger than in the baseline, the majority of generation is still from large-scale technologies. Over 2.5TWh of biomass CHP is deployed by 2020, almost all of which is in standalone installations rather than those connected to district heating sites, due to the high additional cost of installing a district heating system.

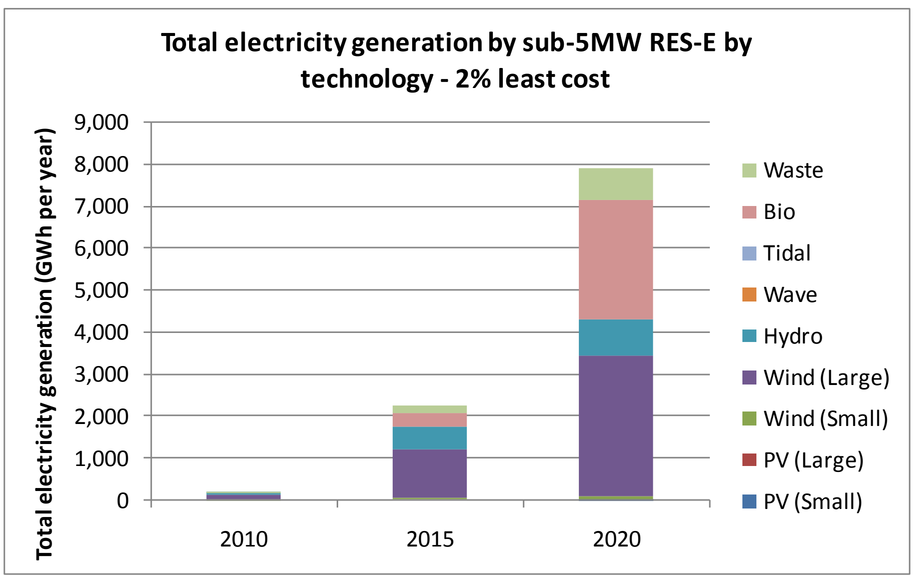

Figure 3 Electricity generation from sub-5MW renewables - £155/MWh tariff

An alternative to pursuing a least cost approach in the design of the policy is to aim to stimulate across a wide range of technologies and scales. For small-scale consumers who can only access small, higher-cost technologies, tariffs significantly higher than £155/MWh are required. Table 1 shows the tariff levels for two scenarios that result in more diverse technology mixes. In the 'community bias' scenario, tariffs are set specifically to encourage deployment of community- and domestic-scale technologies, such as small and medium wind and PV systems.

Table 1 Tariff levels for 2% diverse and community runs

Technology	Size	2% diverse mix		2% community bias	
		Initial tariff (£/MWh)	Degression[2] (% per year)	Initial tariff (£/MWh)	Degression (% per year)
PV	Domestic	£400	5%	£400	5%
	4-10kW	£380	5%	£380	5%
	10-100kW	£250	5%	£350	5%
	100-5000kW	£250	5%	£300	5%
	Stand-alone	£250	5%	£300	5%
Wind	Micro	£200	0%	£300	0%
	1-15kW	£200	0%	£300	0%
	15-50kW	£200	0%	£250	0%
	50-250kW	£200	0%	£200	0%
	250-500kW	£200	0%	£180	0%
	500-3000kW	£160	0%	£143	0%
Hydro	1-10kW	£145	0%	£145	0%
	10-50kW	£145	0%	£145	0%
	50-500kW	£145	0%	£140	0%
	500kW+	£140	0%	£140	0%
Wave	All types	£250	2%	£250	2%
Tidal	All types	£250	0%	£250	0%
Biomass	Heat turbine	£130	0%	£130	0%
	ORC	£130	0%	£130	0%
	Steam turbine CHP	£130	0%	£130	0%
	Electricity only	£0	0%	£0	0%
Waste	Electricity only	£100	0%	£100	0%
	AD	£100	0%	£100	0%
	Incineration	£100	0%	£100	0%

Figure 4 shows the electricity generation mix with the tariffs shown above. Although the overall generation remains constant at 8TWh, the diversity of the generation mix is significantly increased. In the 'community-bias' scenario, over 1.5TWh per year are generated from PV, the majority of which is from domestic-scale installations. Small wind turbines up to 250kW in size also contribute 0.5TWh in 2020. The costs of increasing technology diversity is

[2] The degression rate is the annual reduction in the tariff paid to new installations. The degression rate reflects anticipated reductions in technology costs and reduces overpayments to investors purchasing systems in the future.

high, with a cumulative resource cost (defined as the total money spent on capital equipment and running costs for renewable energy plant) by 2020 of nearly £4 billion relative to Business as Usual, compared to £1.0 billion in the least cost scenario.

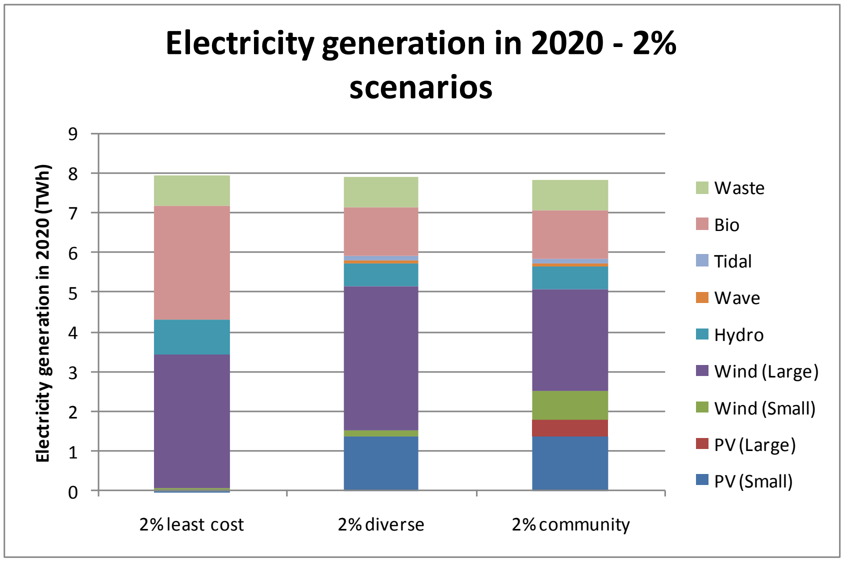

Figure 4 Renewable electricity generation in 2020 - diverse and community scenarios

Figure 5 shows the supply curve for sub-5MW renewable electricity for the 2% 'community scenario. The width of each bar represents the amount of electricity generated by each technology in 2020, while the height shows the levelised cost of energy in 2020 (in £ per MWh). Note that for simplicity, only the 2020 technology costs are shown. For technologies whose costs decrease over time, some of the resource shown in Figure 5 is deployed earlier than 2020 and so has a higher generating cost. All of the generation costs are calculated using a 10% cost of capital over the project lifetime. The figure shows that the waste technologies have the lowest cost of electricity, since plants earn revenue from heat sales and waste gate fees. Anaerobic digestion makes the largest contribution of the sub-5MW waste technologies. There is nearly 6TWh of resource available in 2020 for a generating cost of less than £150/MWh. There is then a significant gap between the generating costs of biomass CHP and small wind turbines while the levelised cost of domestic PV is still £450/MWh in 2020, at a 10% rate of return.

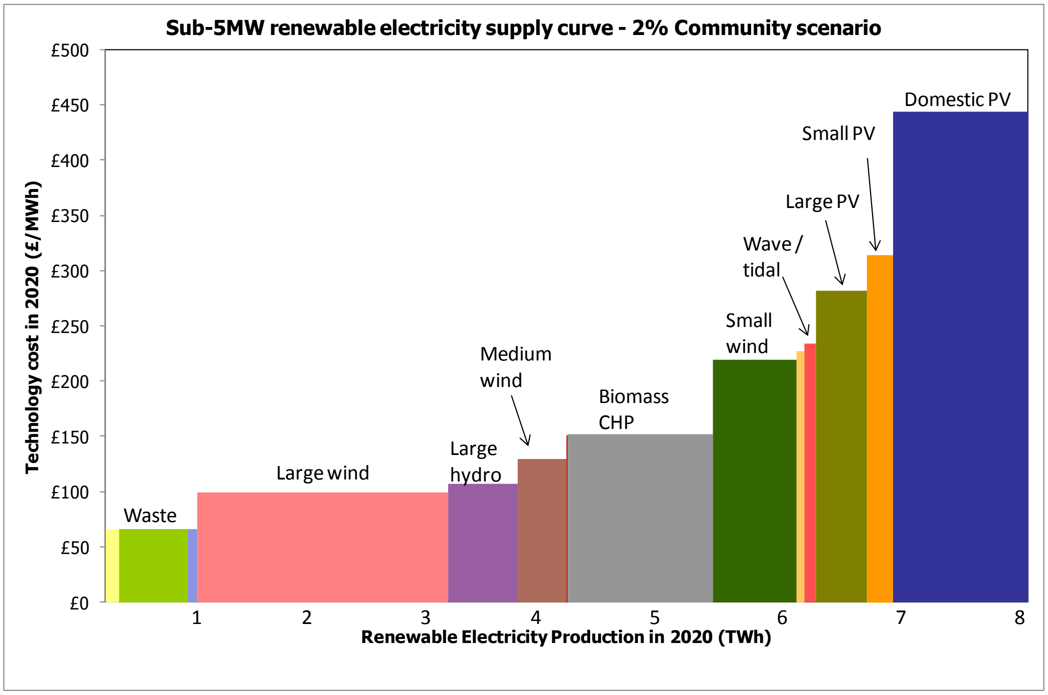

Figure 5 Renewable electricity supply curve - community bias

Conclusions

The results above illustrate the overall costs of meeting a given generation target with different technology mixes. The analysis also quantifies the effects of a range of other issues relevant to the design of Feed-in Tariffs. The key conclusions are summarised below:

- A 2% generation target can be achieved at relatively low cost using mega-watt scale technologies. The cumulative resource cost by 2020 is £1.0 billion higher than business as usual. Diversifying the technology mix to include domestic-scale PV and wind comes at a high cost, with the cumulative resource cost in 2020 increasing to £4 billion.

- Banding tariffs by technology can lead to significant reductions in subsidy costs while maintaining the same overall generation by reducing overpayments to low-cost generators. The importance of banding increases with increasing technology diversity, since the differences in costs between technologies becomes larger than differences within technologies (for example large wind turbines at different wind-speed sites).

- Increasing the generation target to 3.5% of the UK electricity demand significantly increases the cost to the country by 2020, from £1 billion to £4 billion for the least cost scenarios. A 3.5% least cost scenario results in significant uptake of small-scale technologies, with over 3TWh of electricity per year generated from PV and small wind. This is because for ambitious targets, large-scale technologies cannot be deployed quickly enough to meet the target by 2020.

- For technologies whose costs are expected to decrease over time, reducing tariff levels each year is necessary to avoid overpayments to investors making investments in the second half of the next decade. However, matching tariff levels to technology costs from the first year of the policy results in significantly higher policy costs than setting a flat tariff so that the technology is only deployed when its costs decrease. In other words, there is a financial benefit to delaying uptake until technologies are cheaper. The risk of this approach is that if investor demand is low for the first few years of the policy because the tariffs are not sufficiently generous, the industry will not make the investments necessary to deliver large amounts of renewable energy at low cost towards 2020.

- Premium tariffs, where tariff payments are made on top of the market electricity price, carry a higher risk than a fixed tariff with an equivalent total support level, due to volatility of electricity prices[3]. This additional risk is likely to be reflected in a higher cost of capital for projects and higher hurdle rates. This means that overall support must be higher under a premium tariff to encourage a given level of uptake.

- In the results above, it is assumed that tariffs are paid over the lifetime of the technology. Where investors employ high discount rates and place a low financial value on revenues received in the distant future, total subsidy costs can be significantly reduced by paying tariffs over a shorter period. For example, for an investor with a 10% discount rate, a 10 year tariff that provides the same perceived value as a 25 year tariff has a 25% lower lifetime subsidy cost (assessed at the social discount rate of 3.5%).

- The benefit of paying tariffs over a shorter period is highly sensitive to the way in which investors value long term benefits. For an early adopter with a similar discount rate to the social discount rate, there is no benefit to paying tariffs over a shorter period. For investors with very high discount rates, such as many domestic consumers, costs can be reduced by paying tariffs up-front at the point of purchase (capitalisation). The risk of this approach is that the investor has less incentive to continue to operate the system after the majority of the tariff has been paid. In addition, capitalisation requires the energy output of each system to be 'deemed' (estimated), and would require additional verification that the device actually delivered the electricity that it was predicted to generate.

[3] In addition to exposing investors to variability in market electricity prices, premium tariff designs also require that generators participate in the grid balancing and settlement processes. This can reduce the costs to the grid operator of large amounts of intermittent renewable generating capacity, but the transaction costs can be high for small generators. A detailed assessment of fixed and premium tariffs is provided in the companion report on Qualitative Design Issues.

- Tariff designs based on setting tariffs to fulfil a certain policy objective risk 'picking winners', because the uptake of individual technologies is very sensitive to the tariff level. For example, in designing a tariff to deliver a significant quantity of renewable electricity from small-scale PV, the government must 'choose' to support this technology relative to other, less costly alternatives. A more transparent method of setting tariffs is to provide an equal rate of return to all technologies.

- Setting tariffs to provide an 8% rate of return for all technologies encourages uptake of small-scale, higher cost technologies but does not stimulate deployment of large-scale systems. This is because there is a significant proportion of domestic investors who are willing to accept returns of 8% or less, but the majority of large-scale investors have hurdle rates above 8%.

- The treatment of electricity from biomass must be considered carefully in the design of the Feed-in Tariff. A tariff structure that fails to provide additional incentives for plants utilising waste heat is likely to encourage the construction of electricity-only plants. This is an inefficient use of biomass compared to CHP plants and co-firing in gigawatt-scale electricity plants.

- A heat incentive of £10/MWh_{th}, similar to the additional 0.5 ROCs per MWh_e paid to CHP plants under the RO, is sufficient to encourage use of waste heat in on-site applications. However, higher support is required to encourage deployment of plants connected to district heating networks due to the high additional costs involved. This higher support could be provided through the Feed-in Tariff, the Renewable Heat Incentive, or other policy support such as low-cost finance or grants for the construction of the heat distribution networks.

- There is a very large potential for gas-fired CHP available at relatively low cost. A flat tariff of £155/MWh, equivalent to the market electricity price plus the 2 ROCs per MWh currently paid to renewable microgenerators, delivers nearly 22TWh of CHP electricity by 2020. The annual CO_2 savings from gas-fired CHP in that year are over 3 million tonnes. However, the majority of this potential is from domestic-scale devices which are not currently available in commercial quantities. As a result there is some uncertainty over the long term costs of these technologies.

- A flat tariff of £155/MWh for gas-fired CHP has significantly lower subsidy costs than an initial tariff of £240/MWh degressed at 5% per year. This is because uptake is initially constrained by the ability of the industry to ramp up production capacity. Paying higher initial tariffs results in overpayments to investors who were willing to invest with lower support levels, while failing to deliver any additional deployment. This supports holding tariffs at the same level for the first few years of the policy, before introducing degression to match any further cost reductions.

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Contact details:

Element Energy

Alex Stewart (Consultant)
Twenty Station Road
Cambridge
CB1 2JD
01223 227533
alex.stewart@element-energy.co.uk

Ben Madden (Director)
60 Newman Street
London
W1T 3DA
ben.madden@element-energy.co.uk

2 Introduction

The EU Renewable Energy Directive 2008 sets an ambitious target that 20% of energy used in the EU in 2020 should come from renewable sources. This target applies to all energy uses including electricity, heat and transport. The Directive sets out individual targets for each member state, and the UK must derive 15% of its final energy consumption from renewable sources. The Energy Strategy will set out how the UK Government intends to meet this target over the next ten years. In the RES consultation published in 2008, the Government indicated that renewable electricity would make a major contribution to the overall target, with 30-35% of electricity being renewable in 2020. While the majority of this increase will be from large-scale technologies such as onshore and offshore wind delivered through the Renewables Obligation, it is expected that a contribution from smaller-scale technologies will be required if the overall target is to be met.

The Energy Act 2008 gives the Government powers to introduce Feed-in Tariffs for small-scale generators with capacities under $5MW_e$. Feed-in Tariffs will apply to a wide range of technologies, from domestic-scale solar photovoltaics and wind systems through to megawatt scale wind turbines and biomass electricity plants. Feed-in Tariffs are widely used to promote renewable electricity in continental Europe, and have led to widespread deployment of higher-cost technologies such as photovoltaics that have not been delivered in large numbers under the UK's Renewable Obligation. While all Feed-in Tariff schemes share common features, such as guaranteed payments for eligible generators and guaranteed grid access, the detailed design and implementation of the policies differ markedly between member states. For example, in some schemes generators receive fixed tariffs for generated electricity that are independent of the market electricity price, while in other schemes generators are required to participate in the electricity market in the same way that large fossil fuel plants do.

Element Energy and Pöyry were commissioned in early 2009 to conduct a detailed review and analysis of Feed-in Tariff schemes across the EU to inform the design of the Feed-in Tariff that will be implemented in England, Scotland and Wales in April 2010. The work was split into two parallel streams. The first stream was an exhaustive qualitative review of Feed-in Tariff design parameters, drawing on experience of best-practice from existing schemes. That report is published by Pöyry and Element Energy alongside this one. The second stream is a quantitative analysis of the optimal design of Feed-in Tariffs for Great Britain. This was based on the development of a model of the potential for sub-5MW renewable electricity in Great Britain, which can be used to investigate technology uptake under different Feed-in Tariff designs.

The modelling approach, described in detail in Section 3, is based on the construction of renewable electricity supply curves showing the size of the resource available at a given generating cost. The resource potentials for each technology were estimated using a combination of industry consultation, literature review and primary analysis using Geographical Information Systems (GIS). The resource potentials were combined with a technology cost and performance model and a representation of investor behaviour based on telephone discussions with renewable energy investors. The resulting model is able to project uptake of each renewable technology under a wide range of feed-in tariff designs. These range from relatively simple designs that aim to minimise the costs to the economy and electricity consumers for a given electricity generation target, to more complex approaches based on encouraging a wide range of technologies and scales or offering equal rates of return to all investors. Many design issues discussed in the qualitative report, such as the effects of premium versus fixed tariffs and degression, can be investigated and quantified using the model.

3 Methodology

3.1 Overview of model methodology

This section describes the modelling approach employed to investigate the effect of different Feed-in Tariff designs on the uptake of sub-5MW renewable electricity. The overall approach builds on previous Element Energy analysis of the potential for medium-scale wind and PV in the commercial buildings sector[4], and is based on the construction of renewable energy supply curves, which show the cost of electricity and potential resource for each technology (see Figure 6). This is similar to the approach employed by Green-X, which modelled uptake of renewable electricity technologies under Feed-in Tariffs and tradable green certificate schemes in the EU[5].

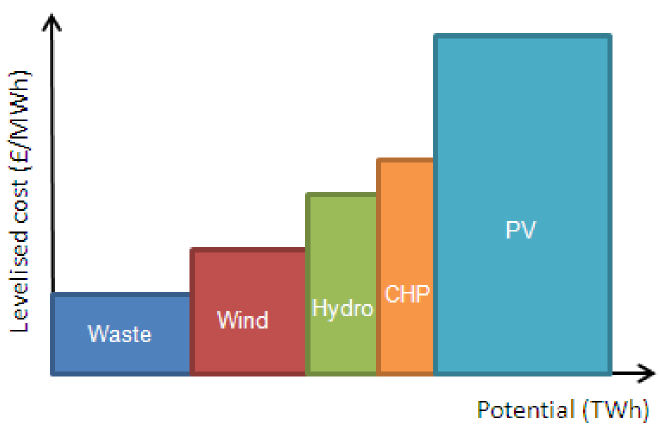


Figure 6 Illustrative renewable energy supply curve

The overall model structure is shown in Figure 7. Absolute supply curves are derived for each technology by combining cost data and a model of investor behaviour with the assessment of the technical potential described in Section 3.3. The absolute supply curves show the maximum quantity of renewable technology that can be deployed at a given generation cost; they do not include any demand or supply-side constraints. These market and social barriers are then applied to the absolute supply curve to yield dynamic supply curves, which show the maximum deployment for each technology in a given year.

The renewable electricity technologies on the supply curve are disaggregated according to the following attributes:

[4] Element Energy (2008): The Growth Potential for On-site Renewable Electricity in the Non-domestic Sector.
[5] Green-X (2004) – Deriving optimal promotion strategies for increasing the share of renewable electricity in a dynamic European electricity market.

- Technology type - e.g. PV or wind
- Technology scale - e.g. building mounted, small and large wind
- Site type - e.g. wind-speed, heat load, insolation level
- Investor - e.g. householder or utility. The investor type affects the cost of capital and hence the overall project costs.
- Year - this influences the technology costs and the maximum deployment in that year.

Once the dynamic supply curves have been established, a revenue model is used to calculate the total income per megawatt-hour for each technology. The revenue model includes the market value of electricity and heat, as well as payments made from Feed-in Tariffs. If the total revenue exceeds the generating costs for a given technology and investors, the potential of that technology in that year is deployed. The model reports uptake in terms of numbers of installations, electricity generation and installed capacity for each technology and year. It also reports net costs and benefits to the country in line with Government guidelines on appraising low carbon policies.

Feedbacks are implemented at several stages in the model. The market and social barriers used to build the dynamic supply curves for each year depend on the cumulative uptake of each technology. For example, the amount of PV that can be deployed in each year depends on the sales in the last year since the industry has a finite growth rate. In addition, tariff levels paid to generators under the FIT can be linked to uptake, so that tariffs are reduced if uptake in the last year exceeded a set value. This is implemented in Germany, where tariffs are ‘degressed’ by an additional 1% over the standard reduction last year’s installed capacity exceeded a pre-defined value.

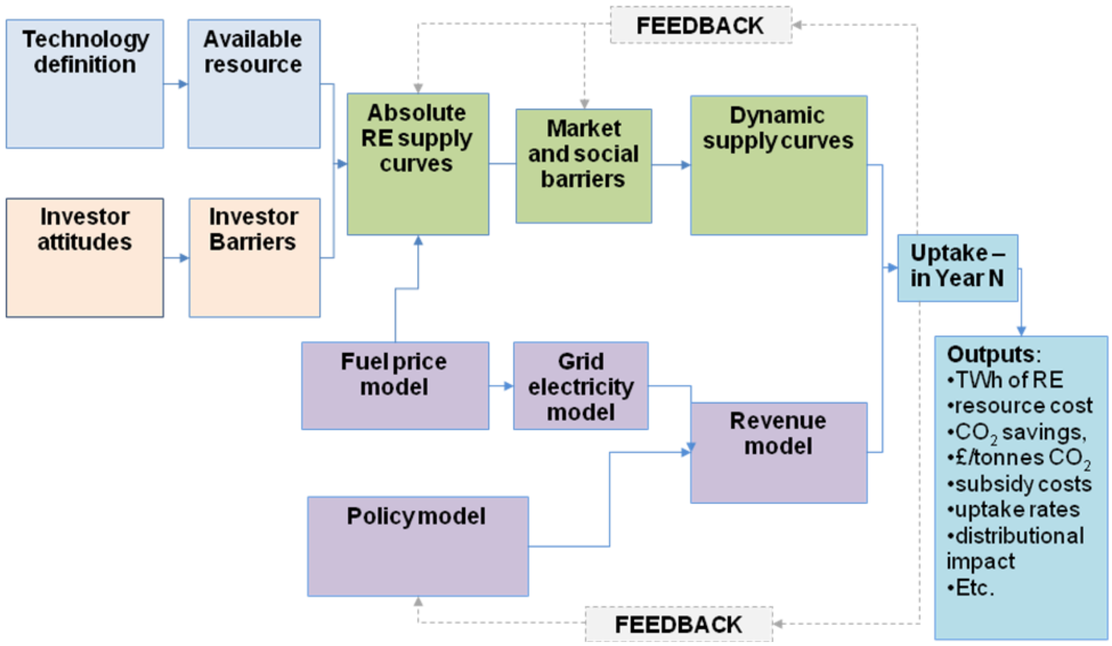


Figure 7 Overview of model structure

3.1.1 Technologies considered

Following discussions with DECC, the following technologies were considered in the model:

- Photovoltaics
- Onshore wind
- Hydroelectric power
- Wave power
- Tidal power
- Biomass CHP
- Waste to energy technologies
- Gas-fired CHP (up to 50kW$_e$)

In line with the capacity limit for the Feed-in Tariff described in the Energy Act 2008, only sub-5MW$_e$ projects considered. Some of the technologies considered, such as incineration, are traditionally sized higher than 5MW$_e$ due to economies of scale. Where this was the case, only sub-5MW plants were included in the model, and the total resource was restricted to sites suitable for smaller plants (see Section 3.3).

3.2 Investor behaviour

The uptake of renewable electricity technologies under a supportive Feed-in Tariff depends on whether or not the rate of return of the project exceeds the hurdle rate of potential investors. The hurdle rate of large-scale investors is based on their Weighted Average Cost of Capital (WACC), which is itself dependent on the risk associated with the project. This means that projects employing novel technologies, such as marine power or advanced thermal treatment of waste, will have higher hurdle rates than those using established technologies, to reflect the risk of technology failure.

The hurdle rates assumed for large-scale investors are based on telephone discussions with a number of investors conducted by Pöyry in early 2009. Detailed results of these discussions are included in the report by Element and Pöyry on qualitative design issues that accompanies this report. Table 2 summarises the hurdle rates by investor and technology from the discussions. In general utility companies have lower hurdle rates than developers do for similar projects, and rates for novel high risk technologies are two to four percentage points higher for novel, higher risk technologies. The values in Table 2 show the maximum hurdle rates for each technology. To represent the range of hurdle rates observed in the whole population, a distribution of hurdle rates was implemented. Large-scale investors are assumed to have a minimum hurdle rate of 8%, regardless of technology, and the maximum values shown below. The figures below are post-tax nominal hurdle rates.

Table 2 Hurdle rates for large scale investors

		Utility/ESCO		Developer
		Large scale	Medium 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%
	Gasification	12%		14%
	Incineration	8%		10%

Smaller-scale investors such as householders and commercial building do not use a single hurdle rate when assessing investment decisions. Instead, the effective hurdle rate of a project includes a number of intangible factors such as hassle costs and transaction costs, which vary significantly between investors. For example, literature on uptake of energy efficiency measures suggests that many domestic consumers have very high hurdle rates, expecting returns of 20% per year, while early adopters invest in technologies which do not provide positive returns in their lifetimes. To represent this range of consumer behaviour, a distribution of hurdle rates was implemented in the model. At the domestic scale, the minimum hurdle rate was assumed to be 3%, close to the social discount rate of 3.5%, and the maximum was 20%. Commercial building owners are assumed to have a narrower distribution, with minimum and maximum hurdle rates of 6% and 15% respectively. The range of hurdle rates is significantly higher than for large-scale investors described above.

For both large and small-scale consumers, hurdle rates are distributed linearly through the population, as shown in Figure 8. In the figure, P1 and P2 represent the levelised technology costs when assessed at the minimum and maximum hurdle rates. If the total revenue through the feed-in tariff is lower than P1, no uptake occurs. If the revenue is half way between P1 and P2, 50% of the potential in the dynamic supply curve is deployed. If revenues are higher than the levelised cost when assessed at the maximum hurdle rate, 100% of the maximum annual potential is deployed. This implies that increasing revenues beyond these values does not increase technology uptake, but increases producer profits and the total subsidy spend.

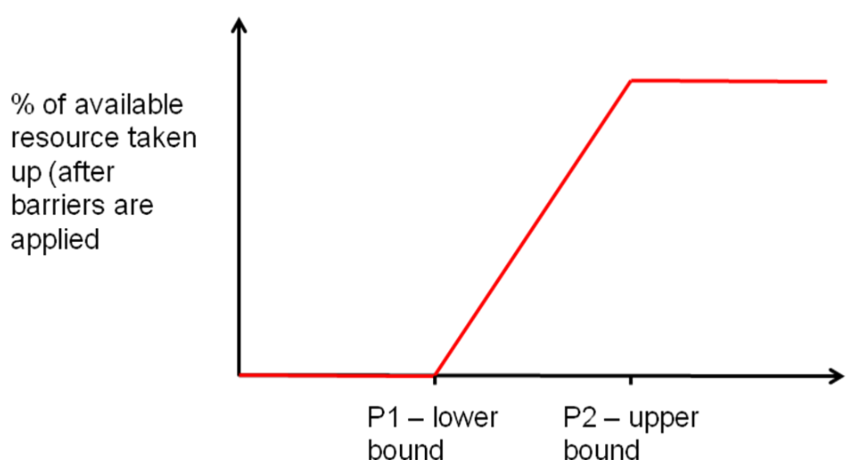


Figure 8 Distribution of investor behaviour in the model

3.3 Assessment of resource potentials

The total technical resource was estimated for each of the technologies considered in the model. The technical potential represents the upper bound for the amount of a technology that can be deployed if sufficient policy and financial support were provided. The technical potential does not include time-dependent constraints such as the maximum growth rate of the industry or a limit on investor demand in a given year; these constraints are imposed on the absolute supply curves to give dynamic supply curves, which show the resource available in a given year.

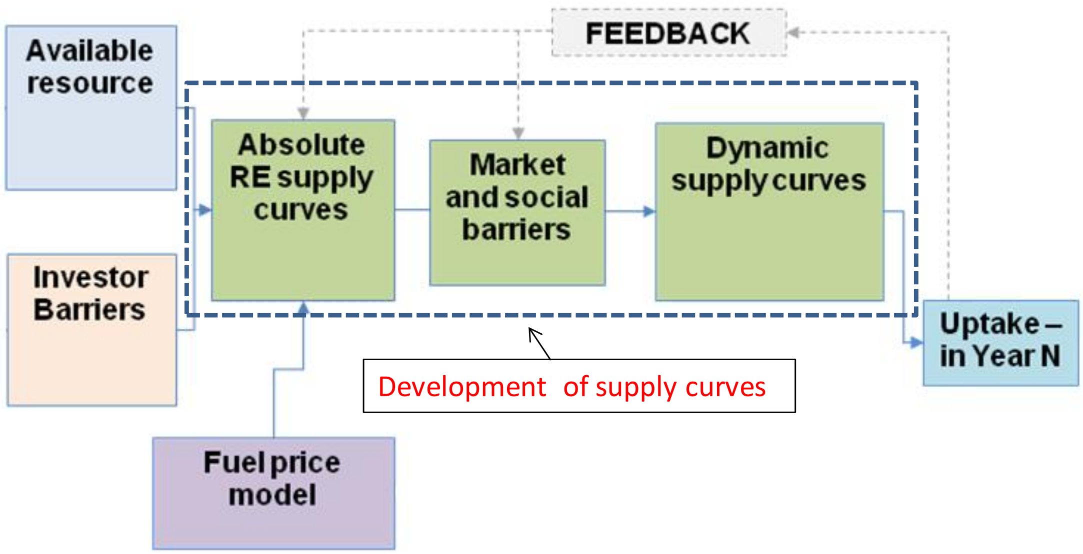


Figure 9 Steps used in the development of dynamic supply curves

The factors constraining the absolute resource potentials are technology-specific. For example, the potential for building-attached photovoltaics is constrained by the amount of available roof space in the commercial and domestic sectors. On-shore wind power is constrained by the availability of high wind-speed sites, as well as by the strength of the local electricity grid and the proximity of buildings. For technologies using a finite feed-stock, such as biomass or waste, the availability of the feed-stock often constrains the overall deployment. For example, anaerobic digestion has a specific requirement for biological waste, and 'competes' with other disposal methods such as advanced thermal treatment and composting for that resource. It should be noted that although the supply of domestically grown biomass is limited due to land availability, the UK can import large quantities of biomass from overseas. For the purposes of this study, it is assumed that the availability of biomass is not a constraint on the potential for sub-5MW systems.

The 5MW capacity cap under the UK Feed-in Tariff makes the estimation of resource potentials for several technologies challenging. For example, wave and tidal technologies are likely to be deployed in clusters with total capacities exceeding $5MW_e$, due to prohibitive costs of grid connection and maintenance for sites far from the shore. Therefore, our assessment of the sub-5MW marine resource excludes sites in deep water that are far from the coast, and only near-shore sites appropriate for smaller projects are included. The methodologies used to estimate the resource potentials for each technology are described in detail in Appendix B.

Table 3 summarises the technical potentials for sub-5MW renewable electricity in the UK. In terms of absolute potential, PV has the highest potential of the renewable technologies with over 60TWh per year. The potential for biomass electricity is over 40TWh a year, even when constrained by heat demands. The potential for gas-fired CHP is extremely large, equivalent to over 25% of UK electricity demand. The majority of this is in the domestic sector, and assumes that a technology such as fuel cell CHP is commercialised that allows high run hours in sites with relatively low heat demands, such as new homes.

Table 3 Summary of resource potentials for sub-5MW electricity in the UK.

Technology	Type	Technical potential (TWh/year)
PV	Domestic	22.3
	Medium/large building attached	29.6
	Stand-alone	8.5
Wind	Micro	3.8
	1.5-15kW	1.1
	15-50kW	1.4
	50-250kW	1.5
	250-500kW	1.6
	500-3000kW	8.4
Hydro	1-100kW	0.5
	100-1000kW	3.0
	1000+ kW	1.3
Wave	Sub-5MW	0.4
Tidal	Sub-5MW	0.2
Biomass	District heating - new build	1.5
	District heating - retrofit	17.0
	Stand-alone commercial	6.0
	Low temperature industrial	18.8
Waste	Advanced Thermal Treatment	0.7
	Anaerobic Digestion	3.3
	Incineration	0.5
Gas CHP	Domestic 1kW	88.7
	1-50kW	23.8
	Total renewable	131.2
	Total including gas CHP	243.7

3.4 Barriers to uptake

As shown above, the technical potential is extremely large for the majority of renewable energy technologies. However, there are numerous barriers that restrict the amount of renewable energy that can be deployed in a given year. There are three barriers within the model that are used to generate dynamic supply curves for each year from the static resource potentials.

3.4.1 Social acceptance

For many renewable energy technologies, social acceptance is a key factor determining the maximum deployment. This is especially true for large scale technologies such as on-shore wind and waste, where there can be strong public opposition due to concerns over visual impact, noise, traffic movements or air quality. The social acceptance of these technologies tends to decrease with increasing deployment, for example as concerns grow with the cumulative impact on the landscape of a large number of wind farms. In addition, developers are likely to exploit sites with smaller anticipated planning issues first, so new deployment over time occurs in more and more 'difficult' sites. For novel technologies with low cumulative deployments, however, social acceptance is likely to increase at first as the public familiarity increases and misconceptions are overcome. Figure 10 shows the social acceptance barriers implemented in the model. The percentage of the remaining potential that can be deployed in a given is assumed to decrease exponentially with the percentage of absolute potential achieved. To reflect the increasing social acceptance of novel technologies with low deployments, the starting point of the function is set sufficiently high that it is less restrictive than supply side barriers.

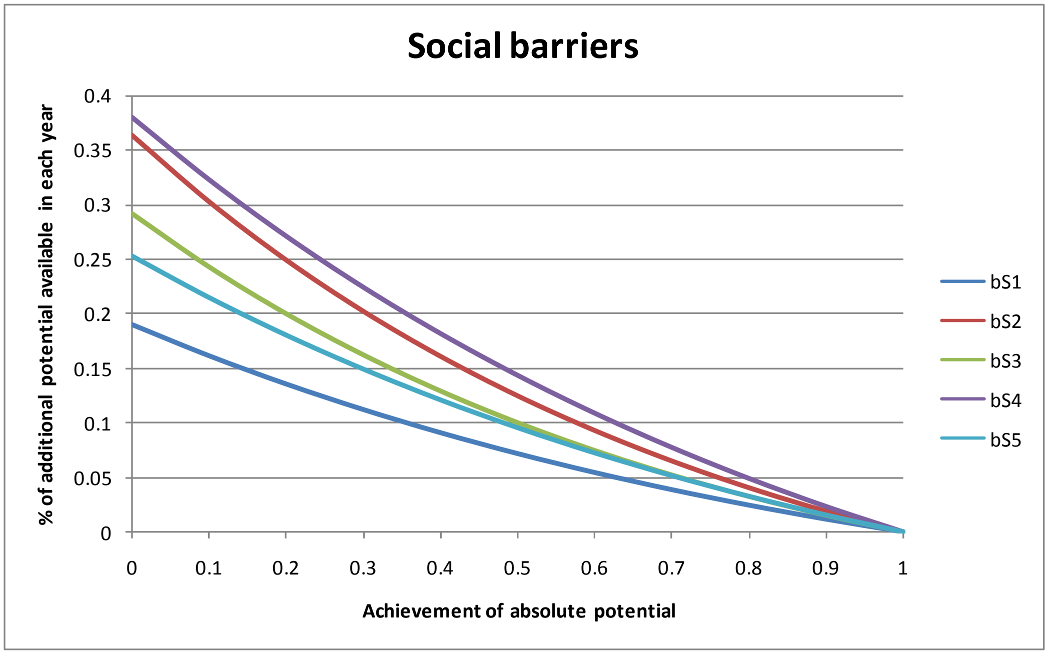


Figure 10 Social acceptance barriers employed in the model. bS1 – bS5 represent different levels of social barriers.

3.4.2 Market barriers

Penetration of new technologies tends to follow an S-shaped curve when market share is plotted against time. This is due to changes in demand and supply at different levels of deployment. For a novel technology entering the market place, investor demand is likely to be low due to lack of awareness and technological uncertainty, as well as high costs due to immature supply chains and manufacturing processes. In turn, the capacity of the supply chain is low since there is insufficient mass-market demand to justify large-scale investments in capacity. As technologies are taken up by early adopters, awareness and hence demand among mass-market consumers increases. This in turn drives increased capacity in the supply chain. In conventional diffusion theory, it is assumed that the maximum rate of deployment occurs at a market share of 50%. After this point, consumer demand decreases as the pool of remaining investors shrinks. For renewable electricity technologies, this reduction in demand also reflects the increased project costs of less-optimal sites, for example those with low wind speeds.

To achieve an S-shaped deployment curve, a function relating the annual rate of deployment to the proportion of absolute potential realised was used, as shown in Figure 11. Less restrictive barriers allow the cumulative deployment to grow faster and for the market to saturate earlier than for a highly restrictive barrier. The exact shape of the curve is set for each technology during the calibration of the model.

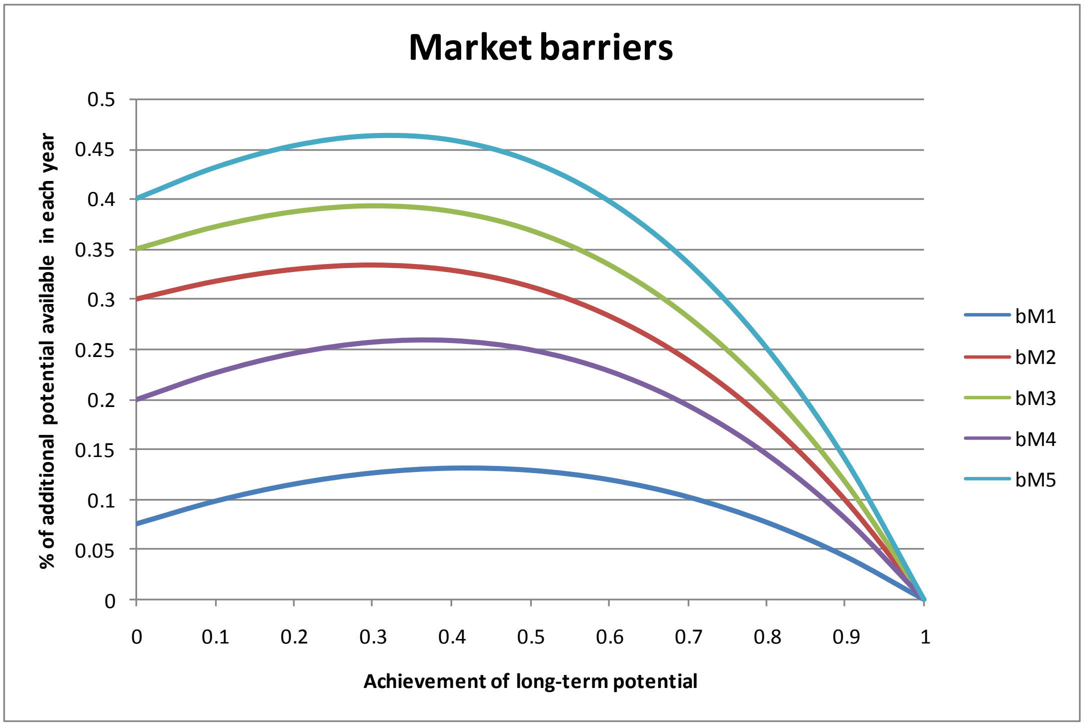


Figure 11 Market constraints implemented in the model. bM1 – bM5 represent different levels of market constraints.

3.4.3 Growth rate constraints

The social and market barriers above are applied independently to each of the technology sub-types. For example, if feed-in tariffs were to cause widespread deployment of large-scale PV but no uptake at the domestic, the proportion of absolute potential achieved will be different for the two sub-types and hence the percentage of the remaining potential that can be deployed in the following year will be different. However, given that the overall supply chains are very similar for the PV industry as a whole, a technology-specific growth constraint is applied across each technology which sets a limit on the increase in annual deployment relative to last year's sales.

The maximum growth rates assumed for each technology are shown in Table 4. Technologies with low current deployment in the UK have higher growth rates than large-scale and established technologies. The growth rates are set to reflect experience from other countries which have seen significant deployment of renewable energy technologies. For example, under the German Feed-in Tariff, the growth rate of the PV industry has averaged 70% per year for the last five years. However, this growth has been highly variable, with a decrease in total sales in one year and a 300% growth rate in another. For technologies with very low current sales in the UK, such as PV, it is likely that spare supply capacity in other countries both in manufacturing and installation could be used to meet rapidly growing UK demand. This means that in the short term, annual UK sales may be able to grow significantly quicker than 70% per year. For this reason, it is assumed that each technology may undergo a one-time increase in annual sales, as shown in Table 4. For example, if a Feed-in Tariff introduced in 2010 for PV stimulates sufficient demand, the industry may install up to 50MW in the first year of the policy, despite this being more than 70% higher than current deployment of less than 10MW per year. Once the annual sales exceed 50MW, the industry then grows at the maximum growth rate shown. It should be noted that these one-time increases are conservative estimates. During the growth of the PV industry in Germany, much larger year on year increases in sales occurred in individual years. However, the average annual growth rate over the last five years has been close to 70%.

Table 4 Maximum technology growth rates

Technology	Maximum annual growth rate	One time increase permitted
PV	70%	50MW
Wind	50%	50MW
Hydro	70%	10MW
Wave	70%	10MW
Tidal	70%	10MW
Biomass	50%	10MW
Waste	30%	10MW

3.5 Model Calibration

Once the technology cost and performance data had been combined with the absolute and dynamic resource potentials, the model was calibrated to ensure that it reflected experience of other countries which have successfully deployed renewable energy technologies. Calibration was achieved by setting the market and social barriers for each technology so that they matched historic UK uptake in the baseline, and levels of uptake under generous Feed-in Tariffs were consistent with growth rates observed in other countries and industries.

Figure 12 shows the results of the calibration process for PV. Two data series have been used for the calibration. The first is historic uptake that occurred in the UK since the start of the decade, based on data from the IEA. Annual PV installations remained very low, at between 3 and 5MW. Since many of these installations were supported with capital grants under the Major PV Demonstration Programme and Low Carbon Buildings Programme, historic capital subsidies were included in the model. The second data series used in the calibration is PV deployment in Germany under the Feed-in Tariff. Since its introduction in 2002, the PV industry has grown rapidly, with over 1GW of modules installed in 2008. Although the tariff structures are slightly different from the ones modelled for the UK, and soft loans were widely available to consumers when the policy began, the German deployment data still provides a useful indication of how PV may grow in the UK under generous policy support. For the purposes of the calibration, the German data were time-shifted so that the policy 'started' in 2010. Figure 12 shows that the model can closely replicate both historic UK uptake and deployment under a German-style feed-in tariff.

There were no data available on the historic deployment of sub-5MW systems under European Feed-in Tariffs for wind power, since the UK is unique in imposing a 5MW eligibility limit. In this case, historic UK uptake data from the ROC Register[6] on sub-5MW generators were used in the calibration. For technologies with no historic deployment such as wave and tidal power, the barriers were set equal to other technologies for which data were available.

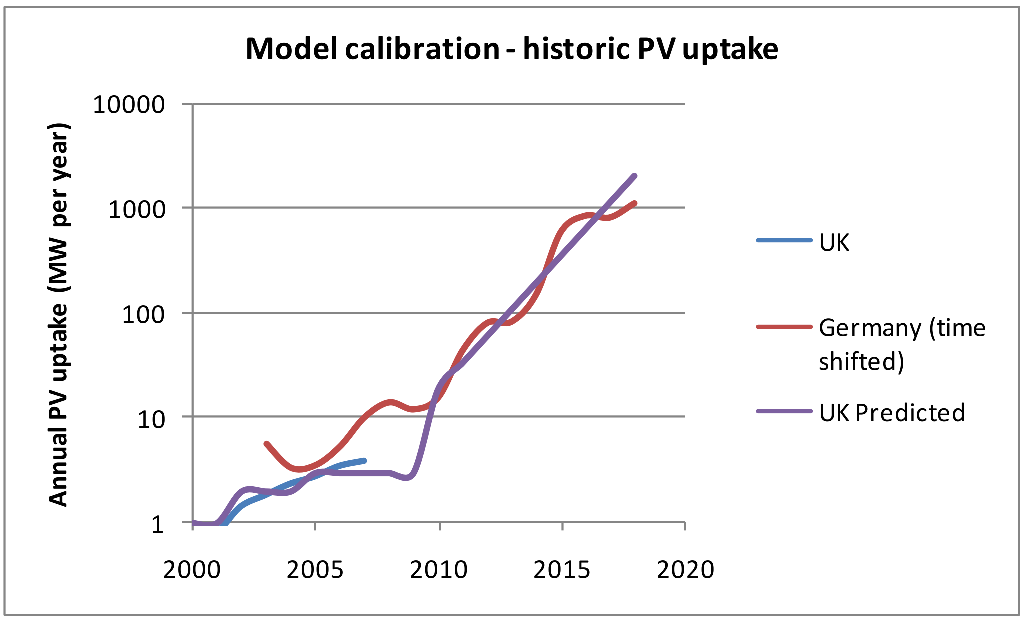


Figure 12 Calibration of model against historic uptake – PV

[6] https://www.renewablesandchp.ofgem.gov.uk/

3.6 Fuel prices

Fuel prices used in the model are based on DECC's fossil fuel price scenarios. These contain projections for the price of electricity and gas for domestic, commercial and industrial consumers from 2008 to 2025. The projections are split into four scenarios from a low energy demand case to a 'significant supply constraints' scenario, where prices increase substantially towards the end of the decade. The tables below show the projected electricity prices for each of the four scenarios. All figures are in 2008 prices. The central projection ('Timely investment, moderate demand') was used in all model runs unless stated otherwise.

The figures below include a CO_2 price and are the prices that consumers pay for electricity. In the absence of additional support under the Feed-in tariff, the prices also represent the value received by renewable energy generators. Electricity that is generated and used on-site is valued at the retail price, while exported electricity is valued at the wholesale price. Small renewable energy systems that are linked to nearby buildings, for example PV and small wind turbines, are assumed to export 50% of their output to the grid, while large-scale technologies are assumed to export their entire output at the wholesale price.

For the purposes of calculating resource costs in the cost-benefit analysis, modified electricity prices were used that did not include carbon prices or taxes.

Table 5 Electricity prices – Low Energy Demand

Year	Domestic(p/kWh)	Commercial (p/kWh)	Industrial (p/kWh)	Wholesale (p/kWh)
2008	14.93	9.97	11.46	7.38
2010	12.48	7.64	9.12	4.78
2015	11.94	7.74	9.22	4.43
2020	12.85	8.59	10.08	4.56

Table 6 Electricity prices – Timely investment, moderate demand

Year	Retail (p/kWh)	Commercial (p/kWh)	Industrial (p/kWh)	Wholesale (p/kWh)
2008	14.93	9.97	11.46	7.42
2010	15.06	10.09	11.58	5.92
2015	14.60	10.27	11.75	5.85
2020	15.87	11.47	12.96	6.25

Table 7 Electricity prices – High demand, producers' market power

Year	Retail (p/kWh)	Commercial (p/kWh)	Industrial (p/kWh)	Wholesale (p/kWh)

2008	14.93	9.97	11.46	7.38
2010	15.81	10.81	12.30	7.94
2015	16.34	11.92	13.41	8.59
2020	18.42	13.90	15.39	9.83

Table 8 Electricity prices – High demand, significant supply constraints

Year	Retail (p/kWh)	Commercial (p/kWh)	Industrial (p/kWh)	Wholesale (p/kWh)
2008	14.93	9.97	11.46	7.38
2010	17.85	12.75	14.24	9.87
2015	19.11	14.56	16.05	11.22
2020	20.61	15.99	17.48	11.91

3.7 Model outputs

For each Feed-in Tariff scenario, the primary model outputs are electricity generation, installed capacity and CO_2 savings for each year of the policy. These outputs are split by technology, size, site type (for example, different wind speed bands) and investor type. For clarity, only partially disaggregated results are shown in the summary graphs and tables in the Results section.

In addition to the primary outputs, the model also provides a detailed cost benefit analysis of each Feed-in Tariff using a methodology agreed with the DECC. Numerous studies that have conducted cost benefit analyses of low carbon policies for all technologies and scales have done so using a wide range of input assumptions and methodologies. This causes difficulties when the costs and benefits of different policies are compared across studies. For this reason, the CBA methodology is described below. Table 9 shows the summary cost benefit analysis outputs as they are presented in the Results section, and each output is described below.

Table 9 Example of summary CBA outputs

Parameter	Unit	Value
Additional electricity generation in 2015	TWh	1.2
Additional electricity generation in 2020	TWh	5.7
Renewable heat generation in 2020	TWh	9.1
Annual resource cost in 2020	£m	199
Cumulative resource cost to 2020	£m	1,037
Annual resource cost in 2020	£/MWh	35
Annual cost to consumers in 2020	£m	331
Cumulative cost to consumers to 2020	£m	1,523
Annual CO2 savings in 2020	MtCO2	2.4

3.7.1 Additional electricity and heat generation

Throughout the CBA, a counterfactual scenario is deducted so that all values are additional to the baseline. The counterfactual scenario is assumed to be the Business as Usual case as set out in the Results section, and assumes that the Renewables Obligation continues to be the main source of support for renewable electricity technologies. This means that additional electricity generation in 2015 is less than the total generated in a given scenario. For example, although the additional electricity generation in 2020 in the table above is 5.7TWh, the total generated in the scenario is 8TWh since 2.3TWh is generated in the baseline.

3.7.2 Resource costs

Resource costs are defined as the costs to the country of pursuing a particular policy relative to a counterfactual scenario. The costs include capital spent on equipment and operating costs, and in this case include savings from electricity generated by renewable technologies. Resource costs explicitly exclude transfers, or payments made from one part of society to another, and so exclude taxes, subsidies and CO_2 prices.

In order to calculate resource costs, capital costs are annualised over the equipment lifetime. Capital costs are annualised using an interest rate of 10% for all consumers, which represents a standard cost of capital that might be applied to renewable energy projects. The cost of capital does not attempt to capture the large range of discount rates seen in domestic consumers, which are represented in the uptake model using a distribution of hurdle rates. This is because the observed high hurdle rates capture a range of hidden and 'hassle costs' that do not accrue to the country as a whole. Therefore the discount rates used in the CBA reflect only the actual cost of capital.

The electricity produced each year by renewable technologies is valued at electricity prices provided by DECC, which exclude the carbon price. Costs occurring in the future are discounted back to present values using the Green Book social discount rate of 3.5% per year.

The annual resource cost per MWh in 2020 is defined as the additional resource cost in that year relative to the baseline divided by the additional electricity generation in that year. This figure is also discounted back to 2008 prices.

3.7.3 Costs to consumers

Since the tariffs paid to renewable energy generators under the Feed-in Tariff are funded by electricity consumers, the cost to consumers records the total value of tariffs paid each year under the policy. Since money paid to generators under a fixed tariff includes the value of the electricity itself, the wholesale price is deducted from the total tariff paid when calculating the cost to consumers. For example, a fixed tariff of £200/MWh represents an additional cost to consumers of £150/MWh if the electricity itself is valued at £50/MWh. Like the resource costs, all future costs are discounted to present values prices at 3.5% per year.

3.7.4 Annual CO_2 savings

To avoid double counting CO_2 savings from renewable heat production in this study and parallel work on the Renewable Heat Incentive, unless stated otherwise the CO_2 savings reported here related only to the renewable electricity generation. The CO_2 displacement for renewable electricity is based on DECC's projection for the marginal long term emissions factor, assumed to be constant throughout the model timeframe at 0.43t/MWh. Biomass is assumed to have a net CO_2 intensity of zero.

4 Baseline

With the exception of landfill and sewage gas, historic investment in sub-5MW renewable electricity technologies has been low. However, due to changing fossil fuel prices and technologies, it is likely that there will be an increase in installed capacity between now and 2020 under current policies. The Business as Usual scenario is a projection of likely deployment under the current policy regime, without any support from a Feed-in Tariff. In many of the model outputs, this baseline is then deducted from the installations occurring in a given Feed-in Tariff scenario, to give the *additional* deployment under the FIT.

4.1.1 Baseline assumptions

In April 2009, the primary support mechanism for renewable electricity, the Renewables Obligation, was modified to encourage deployment of a wide range of renewable technologies. The support payable is banded by technology, so that post-demonstration and emerging technologies receive higher support.

The baseline includes the following support for renewable generators under the banded Renewables Obligation. Note that for simplicity in this model, support from the Low Carbon Buildings Programme is assumed to end at the end of 2009 so that ROCs are the only support mechanism available between 2010 and 2020. Previous analysis by Element Energy suggests that likely supplier contributions to small PV and wind systems under CERT or a post-2011 Supplier Obligation are too low to substantially improve the economics of these systems, and so these policies have not been explicitly modelled in the baseline.

Table 10 RO support received under Business as Usual

Technology	ROCs per MWh
Microgeneration (all systems under 50kWe)	2
PV	2
Wave and tidal power	2
Anaerobic digestion	2
Advanced thermal treatment	2
Biomass CHP	2
Wind	1
Hydro	1
Biomass (electricity only)	1

Table 11 Electricity prices in the Business as Usual scenario (2008 prices)

Year	Retail (p/kWh)	Commercial (p/kWh)	Industrial (p/kWh)	Wholesale (p/kWh)
2008	14.93	9.97	11.46	7.42
2010	15.06	10.09	11.58	5.92
2015	14.60	10.27	11.75	5.85
2020	15.87	11.47	12.96	6.25

4.1.2 Baseline results

Figure 13 shows the total new sub-5MW generation in 2020 under Business as Usual. Note that this excludes projects commissioned before 2010. Total generation in 2020 is 2TWh, with uptake dominated by large scale technologies such as on-shore wind, hydro power and waste. The baseline results suggest that the offering 2 ROCs per MWh to anaerobic digestion, when combined with revenues from gate fees, is sufficient to drive significant uptake. Over 80 1MW anaerobic digestion plants are installed by 2020. Uptake of advanced thermal treatment plants is lower, with 0.1TWh of generation in 2020. Although the levelised costs per MWh are similar to anaerobic digestion, the absolute potential is lower due to competition for waste feedstocks from other technologies, such as incineration with CHP, or larger thermal treatment plants. For example, the first advanced thermal treatment plant to gain ROC accreditation was a $2MW_e$ Energos plant on the Isle of Wight. However, this is a demonstration scale facility; a planned commercial scale plant in Derbyshire is sized at $8MW_e$.[7] This suggests that the future role of sub-5MW advanced thermal treatment plants may be limited.

[7] http://www.energ.co.uk/?OBH=69&ID=21

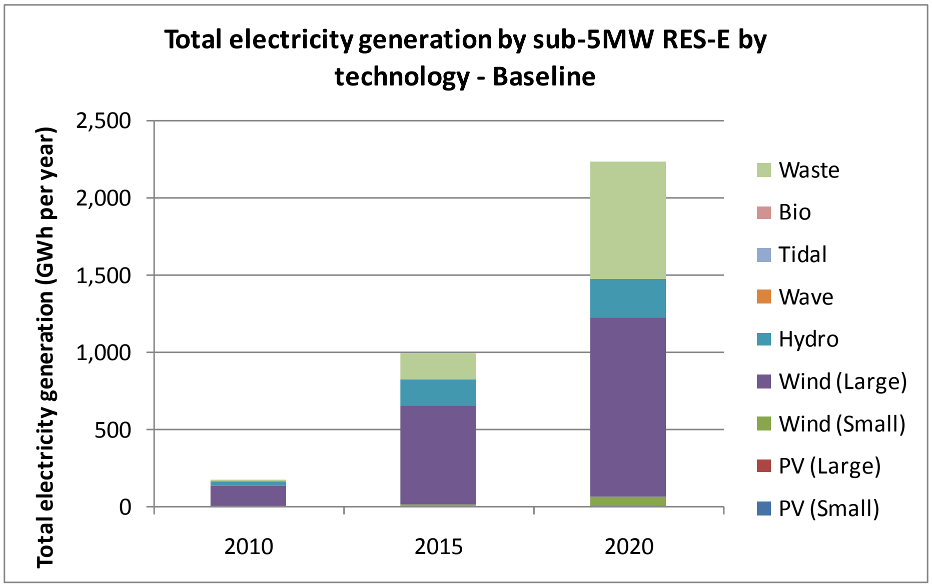


Figure 13 Electricity generation by sub-5MW RES-E in 2020 under Business as Usual

Table 12 shows the size distribution of uptake under the baseline. Although the majority of installed capacity is from large-scale projects, there is significant uptake of small hydro installations. This suggests that 2 ROCs per MWh is sufficient to stimulate uptake of sub-50kW hydro power. There are also over 4,000 small wind installations, defined as those with peak capacities of between 1.5kW and 50kW. Uptake of the other emerging or post-demonstration technologies is negligible, with no deployment of wave or tidal power in the baseline. PV uptake is also extremely low, with 125 systems being installed in 2019 and 2020. Given the assumption that consumers make purchasing decisions based on rates of return, the model is unable to accurately represent uptake by consumers who are willing to accept negative rates of return, which is the case with PV and micro-wind in the baseline. Such early adopters are likely to be few in number compared to the absolute potential for these technologies, and so the distribution of hurdle rates in the model is designed to provide a good representation of mass-market behaviour.

Table 12 Number of installations in 2020 by technology size - Business as Usual

Technology	Size	Cumulative installations in 2020	Cumulative MW in 2020	Annual GWh electricity generation in 2020	Annual CO2 savings in 2020 (MtCO2)
PV	Domestic	125	0	0	0.0
	Small	0	0	0	0.0
	Large	0	0	0	0.0
	Stand-alone	0	0	0	0.0
Wind	Micro	0	0	0	0.0
	Small	4,340	34	57	0.0
	Medium	9	4	8	0.0
	Large	274	549	1,158	0.5
Hydro	Small	365	5	13	0.0
	Large	30	90	236	0.1
Wave	All	0	0	0	0.0
Tidal	All	0	0	0	0.0
Biomass	CHP	0	0	0	0.0
	Electricity only	0	0	0	0.0
Waste	ATT	3	17	121	0.1
	AD	88	88	619	0.3
	Incineration	1	4	25	0.0
Gas CHP	Stirling	0	0	0	0.0
	Fuel cell	146,835	147	730	0.3
	10kW gas	855	9	51	0.0
	50kW gas	931	47	279	0.1
Total renewable		**5,237**	**791**	**2,237**	**1.0**
Total inc. CHP		**153,858**	**993**	**3,298**	**1.4**

Since CHP is strictly a low carbon rather than fully renewable technology, its uptake is not included in the renewable electricity generation and cost-benefit analysis outputs below. Results for CHP are shown separately in Section 5.8.

5 Results and analysis

Designing a Feed-in Tariff to drive uptake of renewable electricity technologies is an inherently complex task. The sizes of the technologies to be stimulated vary from 1kW domestic systems to 5MW industrial plants, and the technologies themselves range from being cost-effective under existing policies to having generating costs over five times the retail electricity price. In addition, costs of many technologies are expected to decrease over time as supply chains mature, and support levels must reflect these changes if significant overpayments to investors are to be avoided.

A thorough review of qualitative Feed-in Tariff design issues has been conducted by Element Energy and Pöyry as part of this project. This review draws on a wide range of policy experience gained in other European countries that have successfully implemented Feed-in Tariffs. Some design issues, such as the process for reviewing tariff levels, cannot be investigated using a quantitative model, and so are covered exclusively in the qualitative report. However, there is a wide range of issues, such as tariff banding, degression and tariff payment periods whose effects on uptake, diversity, and costs can be directly quantified. In the following section, these issues are investigated by setting a 'target' for the amount of renewable generation desired by a given date. By holding overall uptake constant, the effects of policy design on uptake of different technologies, as well as policy costs, can be investigated and seen more clearly. The generation 'targets' used in the main scenarios are 2% and 3.5% of UK electricity demand in 2020. This demand is projected by DECC to be 386TWh in 2020, so the targets correspond to approximately 8TWh and 13.5TWh respectively.

5.1 2% target

For a given target, there is a potentially infinite number of technology combinations that will deliver the electricity generation required. We have used a number of policy approaches to determine the tariff levels for each scenario. In the simplest case, the approach is to meet the generation target while minimising the policy costs as measured by resource cost or the cost to consumers. More complex scenarios aim to encourage the deployment of several technologies, such as community- or domestic-scale PV or wind, which will result in higher costs than the 'least-cost' approach.

5.1.1 Flat tariffs

The simplest tariff structure of all is one in which a single tariff is paid to all generators, regardless of technology, size or year of deployment. The value of the single tariff is equal to the levelised costs of the most expensive technology required to meet the target. In other words, technologies are deployed in ascending order of cost along the supply curve (see Figure 14). Due to the distribution of hurdle rates assumed in the model, each technology has a range of levelised costs and the supply curve is not as discrete as the one shown. Unless otherwise stated, all tariffs are 'fixed tariffs', so levels refer to the total revenue received by the generator (i.e. there are no additional revenues from sale of electricity to the conventional electricity market). A comparison of policies based on flat and premium tariffs can be found in Section 5.4. For a 2% target, the tariff level required is £155/MWh.

In all feed-in tariff scenarios described below, it is assumed that biomass CHP receives support under the RHI for each MWh of renewable heat delivered. The value of the RHI is assumed in the model to remain constant through time at £10/MWh_{th} for a CHP technology with a heat to power ratio of 2.5 to 1, this support is equivalent to an extra electricity tariff of £25/MWh_e relative to an 'electricity-only' plant. This is a similar value to the extra 0.5ROCs payable under the banded Renewables Obligation for biomass plants that operate in CHP mode. For a fuller discussion on biomass electricity and the interaction between the FIT and RHI, see Section 5.7.

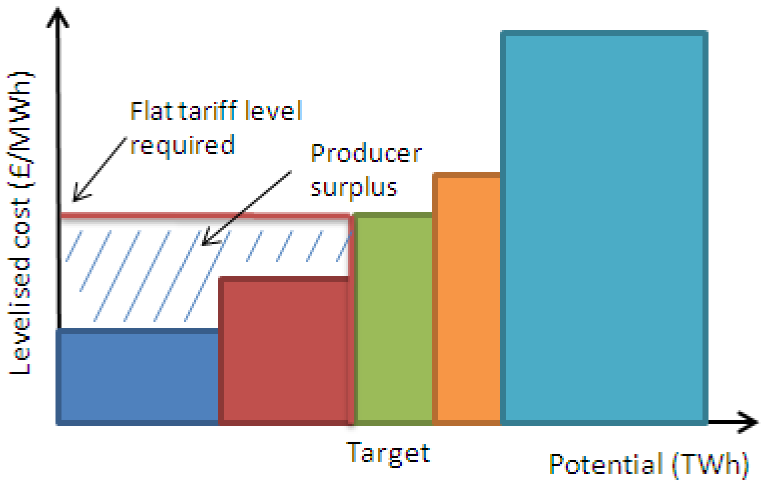


Figure 14 Setting a flat tariff to achieve a generation target using lowest-cost technologies

Figure 15 shows the electricity generation in 2020 with a flat, fixed tariff of £155/MWh. The target is met exclusively by large-scale technologies, with large wind-turbines providing 3TWh in 2020. The combination of the FIT and RHI is sufficient to drive uptake of over 700MW of biomass CHP, delivering 2.5TWh of renewable electricity in 2020. The majority of this capacity is in standalone installations linked to large individual heat demands rather than systems connected to district heating networks, which are significantly more expensive. Uptake of higher cost technologies remains negligible in this scenario, since £155/MWh is well below the levelised costs of marine systems and PV.

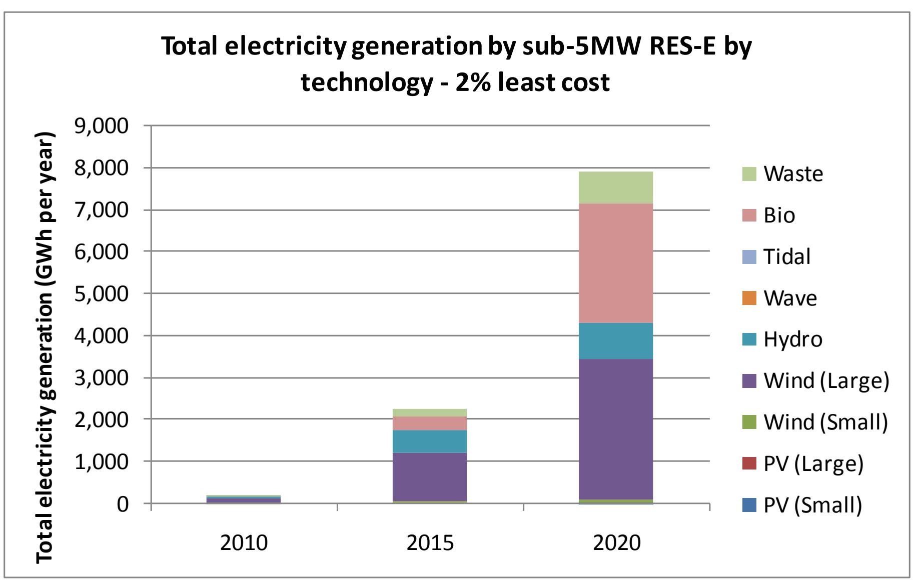


Figure 15 Electricity generation in 2020 - £155/MWh flat tariff

Table 13 shows a summary of the cost-benefit analysis outputs for the flat tariff. All outputs in the CBA are relative to the baseline, so the *additional* electricity generation in 2020 is 5.7TWh, since 2TWh were generated under Business as Usual. The cumulative resource cost in 2020 is £1 billion. The cumulative cost to consumers in 2020 is £1.5 billion, implying that some investors are receiving higher revenues than those that would be required to make the investment attractive.

Table 13 Summary CBA outputs - £155/MWh flat tariff

Parameter	Unit	Value
Additional electricity generation in 2015	TWh	1.2
Additional electricity generation in 2020	TWh	5.7
Renewable heat generation in 2020	TWh	9.1
Annual resource cost in 2020	£m	199
Cumulative resource cost to 2020	£m	1,037
Annual resource cost in 2020	£/MWh	35
Annual cost to consumers in 2020	£m	331
Cumulative cost to consumers to 2020	£m	1,523
Annual CO2 savings in 2020	MtCO2	2.4

5.1.2 Tariff banding

Wherever technologies show significant differences in cost, a flat tariff design will result in overpayments to the lowest-cost generators. As the generation target increases and higher cost technologies on the supply curve are required to meet that target, the overpayments increase significantly. The shaded area in Figure 14 shows the producer surplus for low-cost generators. Producer surplus is defined as the difference between what an investor is paid and the minimum amount he would have to be paid and still make the investment. One solution to overcome this issue, and the one employed in almost all EU Feed-in Tariff schemes, is to band the tariff by technology. Tariffs can be set so that each technology receives support equal to its levelised costs per MWh, with more costly technologies receiving higher support. For technologies with a wide range of costs, such as large wind turbines at different wind-speeds, a single tariff is set for the purposes of the model that provides sufficient returns for the majority of sites.

Figure 16 illustrates a banded Feed-in Tariff design, where tariff levels are set equal to the levelised costs for each technology. The shaded area represents the reduction in producer surplus of the banded tariff relative to a flat tariff delivering the same overall generation target.

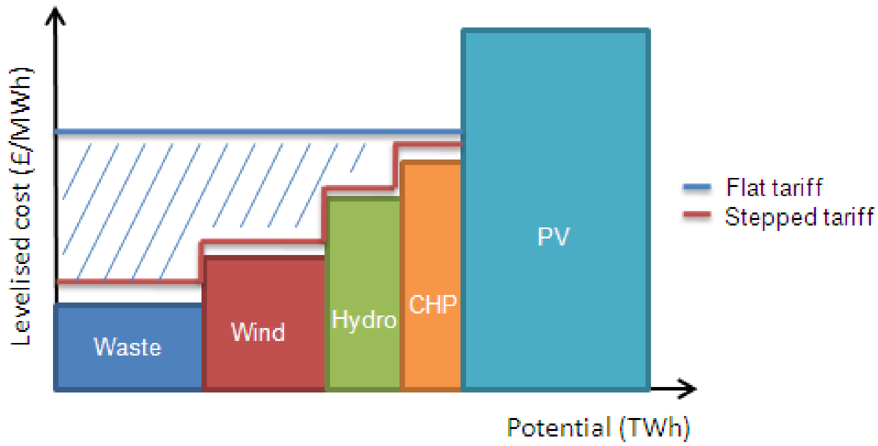


Figure 16 Illustration of a stepped tariff design

The potential for reducing rents through technology banding is relatively limited in the 2% scenario. Waste technologies are available at a lower cost than £155/MWh, and reducing the tariff paid to these projects reduces the cumulative cost to consumers in 2020 by £50 million without affecting overall electricity generation. The limited effect of banding occurs because the rents caused by differences in costs between technologies are small compared with cost differences within a technology due to scale or resource. These differences are particularly large for wind turbines at different wind-speeds, where levelised costs in 2010 vary from between £70/MWh at 8m/s to £150/MWh at 5.5 m/s. There is also significant variation in levelised costs between different turbine sizes at the same wind-speed. To match tariff levels to the levelised costs for each turbine and wind-speed band would require a large number of bands, adding significant administrative complexity to the policy. Options for reducing rents for low-cost generators without multiple tariff bands include volume-based tariffs, where tariff levels decrease as electricity output rises. This means that a wind turbine in a low wind-speed site receives a greater proportion of its tariff payments at a higher level, increasing the average revenue per MWh generated. 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.

5.1.3 Least cost scenarios

If the banded tariff described in Section 5.1.2 were modified to include varying tariffs for different wind-speeds, it would be close to the lowest cost solution for meeting the 2% target. Since the cost of a policy can be measured by resource cost or the costs passed on to electricity consumers, it useful to define the term ‘least cost’, since a given design can minimise one cost without the other.

A flat tariff set to deliver a given target will always minimise the resource cost of the policy, since technologies are always deployed in ascending order on the supply curve. As the generation target increases, a higher flat tariff level will be required to deliver that target, and the average resource cost will increase. The tariff will still deliver the lowest cost technology mix at the higher target.

However, as an unbanded, flat tariff is increased to deliver a greater amount of renewable electricity, the rents paid to low cost generators increases, so the policy is not 'least-cost' with respect to the subsidy costs. Where the objective of the policy is to minimise the overall subsidy costs passed on to consumers, and hence the impact on electricity bills, banding is an essential part of the policy design. Thus a well-designed, banded tariff will minimise both the resource costs and costs to consumers.

It should also be noted that the cost of a policy depends not only on the technology mix deployed, but also on profile of uptake over time. Given that money spent in the future is discounted by government at the social discount rate 3.5% per year, a policy that leads to the highest deployment close to 2020 will have a lower policy cost than the same generation deployed earlier in the decade.

This applies even to technologies whose costs are not projected to decrease over time, although for small scale technologies whose costs are expected to decrease significantly there are additional savings. Delaying deployment of small wind and PV until close to 2020 will significantly reduce both the resource costs and the tariff levels required to drive the uptake. The risk with this approach is that by failing to encourage uptake early in the decade, supply chains do not develop and technology costs remain high. In addition, industry may not be able to respond quickly to rapidly increasing demand close to 2020 if they have not grown steadily over previous years. This risk is higher for some industries than others. For example, the small wind industry is primarily UK-based, and may depend on UK policy support to grow over the coming years. In contrast, a global industry such as PV is unlikely to be affected by low demand in individual countries. If UK demand were to increase rapidly in a particular year, spare capacity abroad, both in manufacturing and installation, would be available to meet it.

5.1.4 Enhancing technology diversity

While the least-cost scenarios above are effective at meeting a 2% generation target, they do not lead to an increase in diversity of supply since the technologies deployed are the same as those installed under the RO, albeit in a different size range. Government is aware of potential benefits to encouraging uptake of a wider range of technologies, including community- and domestic-scale systems. These benefits include increased security of supply as well as less tangible benefits such as engaging consumers and increasing energy awareness.

For a given generation target, a diverse technology mix increases both resource costs and costs to consumers since technologies are no longer being deployed in order along the supply curve. The figures below show two scenarios based on increasing the technology diversity relative to the least-cost design. The 'diverse mix' aims to drive uptake of a wide range of technologies, although the majority of installed capacity in 2020 is still made up of large scale technologies. The 'community bias' scenario goes further, and specifically targets community- and domestic-scale technologies over large installations. The exact tariff levels applied to each technology are somewhat arbitrary, since they are designed to drive uptake of a wide range of technologies while still meeting an 8TWh overall target. However, these scenarios are a useful demonstration of an indicative technology mix based on the resource potentials, and the resulting policy costs. The tariff levels themselves are set with several technology-specific targets in mind, such as 1TWh from small-scale PV by 2020 in the community scenario. However, the choice of exact tariffs is subjective and simply serves to illustrate the effects of diversifying the technology mix. Table 14 below shows the tariffs levels and degression rates for the two scenarios. The degression rate is the rate at which tariffs are reduced each year for new installations, to reflect reductions in the costs of those technologies (see Section 5.3).

Table 14 Tariff levels for the diverse and community scenarios

		2% diverse mix		2% community bias	
Technology	**Size**	**Initial tariff (£/MWh)**	**Degression (% per year)**	**Initial tariff (£/MWh)**	**Degression (% per year)**
PV	Domestic	£400	5%	£400	5%
	4-10kW	£380	5%	£380	5%
	10-100kW	£250	5%	£350	5%
	100-5000kW	£250	5%	£300	5%
	Stand-alone	£250	5%	£300	5%
Wind	Micro	£200	0%	£200	0%
	1-15kW	£200	0%	£300	0%
	15-50kW	£200	0%	£250	0%
	50-250kW	£200	0%	£200	0%
	250-500kW	£200	0%	£180	0%
	500-3000kW	£160	0%	£143	0%
Hydro	1-10kW	£145	0%	£145	0%
	10-50kW	£145	0%	£145	0%
	50-500kW	£145	0%	£140	0%
	500kW+	£140	0%	£140	0%
Wave	All types	£250	2%	£250	2%
Tidal	All types	£250	0%	£250	0%
Biomass	Heat turbine	£130	0%	£130	0%

	ORC	£130	0%	£130	0%
	Steam turbine CHP	£130	0%	£130	0%
	Electricity only	£0	0%	£0	0%
Waste	Electricity only	£100	0%	£100	0%
	AD	£100	0%	£100	0%
	Incineration	£100	0%	£100	0%

Figure 17 and Figure 18 below show the total generation mix for the two scenarios. Total generation is 8TWh in both scenarios, and large wind remains the largest single contributor to the target. However, the technology diversity is significantly increased compared to the least cost scenario. In the 'community-bias' scenario, over 1.2 TWh of electricity is generated by over 500,000 domestic PV installations with a further 0.6TWh from larger building-attached systems. Small wind also makes a larger contribution to the overall target, with over 47,000 small and medium turbines generating 1.1.TWh in 2020.

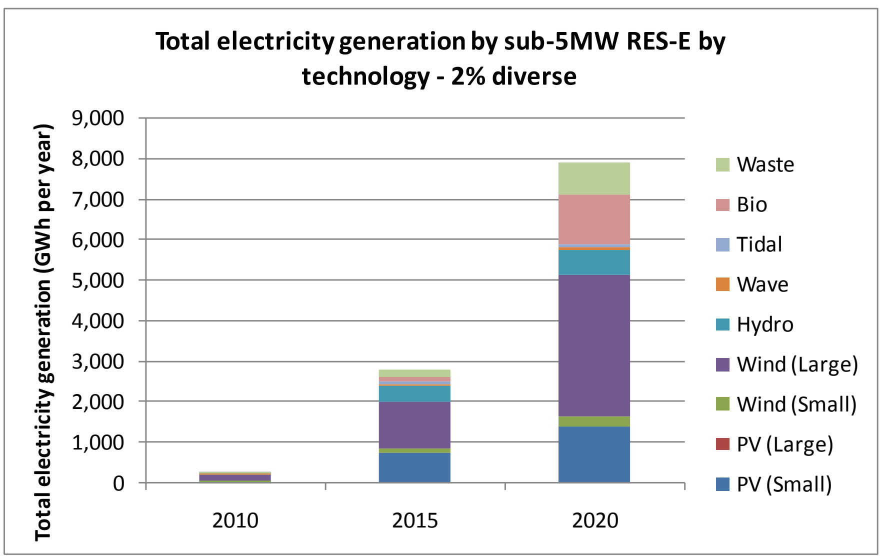


Figure 17 Electricity generation under the 2% diverse scenario

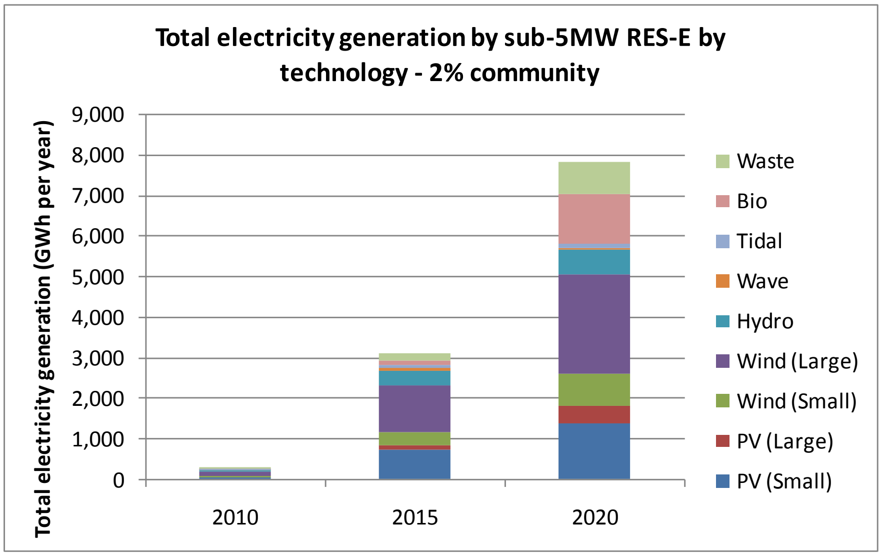


Figure 18 Electricity generation under a 2% community scenario

Increasing the technology diversity comes at a large cost premium over the least-cost scenarios. The cumulative resource costs in 2020 increase from £1 billion in the least cost scenario to £3.6 and £3.9 billion for the diverse and community scenarios, respectively.

For both policies the overall cost to consumers is now lower than the resource cost. There are two reasons for this. The first is that the uptake of large wind is smaller in the diverse scenarios due to lower tariff levels, which significantly reduces the rents paid to systems in optimum sites. The second reason is due to the hurdle rates of consumers purchasing the domestic systems. To represent the wide range of purchasing behaviour observed among domestic consumers, the population is assumed to have a distribution of hurdle rates. At one end of the distribution, early adopter consumers require rates of return of only 3% per year, close to the social discount rate. At the other extreme, consumers require a return of 20% per year, consistent with observed behaviour in the energy efficiency sector.

At the relatively low levels of domestic deployment in the 2% diverse scenarios, the tariff levels are set so that technologies are purchased only by early adopters with relatively low hurdle rates. In other words, the tariff levels provide returns of 3-5% per year to these consumers, but the cost to the economy is evaluated at 10%. This leads to negative rents, where consumers purchase systems despite the tariff level being lower than the levelised costs of the technology. The low hurdle rates of these early adopters can be explained by the fact that they have a low cost of capital, for example paying using their savings, or that they place an implicit value on aspects of the investment not captured by the cost-benefit analysis, such as ‘green benefits’.

Table 15 Summary CBA outputs - 2% diverse and community scenarios

Parameter	Unit	2% diverse	2% community
Additional electricity generation in 2015	TWh	1.8	2.1
Additional electricity generation in 2020	TWh	5.7	5.6
Renewable heat generation in 2020	TWh	3.9	3.9
Annual resource cost in 2020	£m	550	608
Cumulative resource cost to 2020	£m	3,599	3,924
Annual resource cost in 2020	£/MWh	97	109
Annual cost to consumers in 2020	£m	464	506
Cumulative cost to consumers to 2020	£m	2,812	3,128
Annual CO2 savings in 2020	MtCO2	2.4	2.4

Figure 19 shows the supply curve for sub-5MW renewable electricity for the 2% 'community scenario. The width of each bar represents the amount of electricity generated by each technology in 2020, while the height shows the levelised cost of energy in 2020 (in £ per MWh). Note that for simplicity, only the 2020 technology costs are shown. For technologies whose costs decrease over time, some of the resource shown in Figure 19 is deployed earlier than 2020 and so has a higher generating cost. All of the generation costs are calculated using a 10% cost of capital over the project lifetime. The figure shows that the waste technologies have the lowest cost of electricity, since plants earn revenue from heat sales and waste gate fees. Anaerobic digestion makes the largest contribution of the sub-5MW waste technologies. There is nearly 6TWh of resource available in 2020 for a generating cost of less than £150/MWh. There is then a significant gap between the generating costs of biomass CHP and small wind turbines while the levelised cost of domestic PV is still £450/MWh in 2020, at a 10% rate of return.

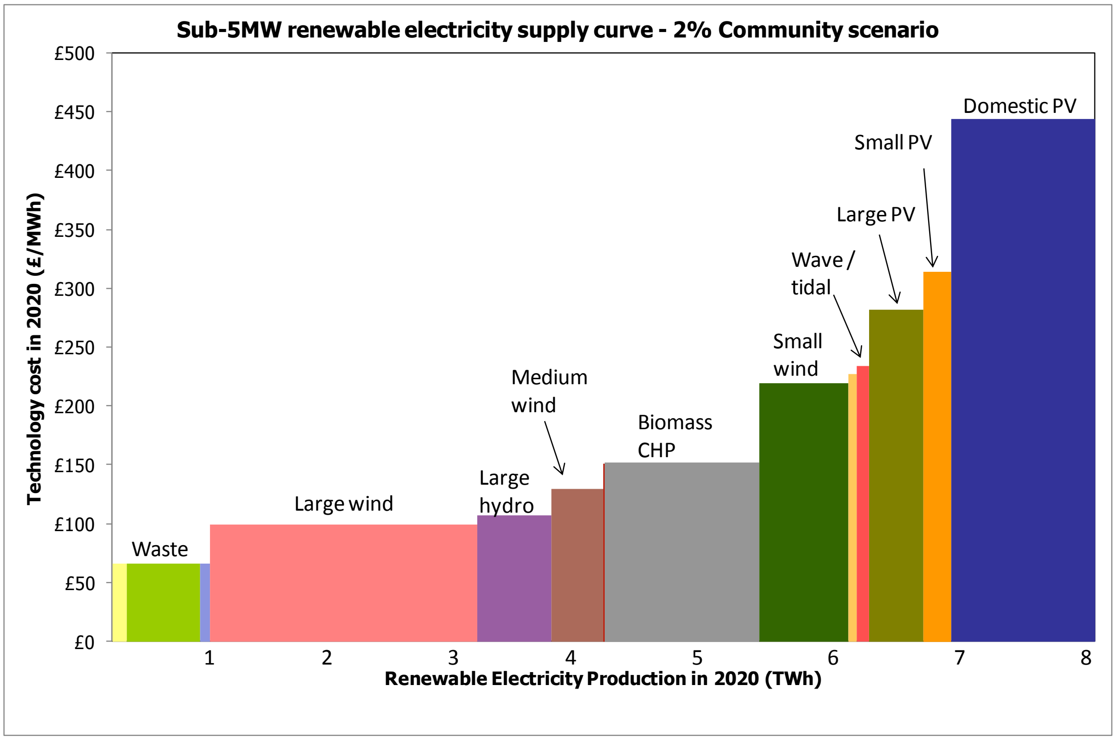


Figure 19 Renewable energy supply curve - 2% community scenario

5.2 3.5% target

The analysis above shows that an 8TWh target for sub-5MW electricity generation in 2020 can be met entirely using large scale technologies if the objective is to minimise the cost of the policy. For higher generation targets, demand and supply side barriers constrain the rates of deployment of large scale technologies. This means that a more diverse mixture of technologies and scales is required. The following scenarios show the effect of raising the electricity generation target from 2% of UK electricity to 3.5% by 2020, equivalent to 13.5TWh per year.

5.2.1 Flat tariff

A 3.5% target can be met using a single flat tariff applied across all technologies and scales in the same way as for the 2% tariff. The diverse technology mix required to meet a 3.5% target significantly increases the value of the flat tariff from £155/MWh to £270/MWh, due to the high cost of small wind and PV systems. The technology mix for the flat tariff scenario is shown in Figure 20. Large scale technologies such as wind, biomass and hydro still contribute to the majority of the target, but significant deployment of PV occurs by 2020, with nearly 2TWh of electricity generated in that year. Small wind also contributes 0.7TWh from 33,000 turbines. Uptake of domestic scale systems remains low, with 0.1TWh generated from 50,000 systems, while uptake of micro-wind turbines is negligible at the £270/MWh tariff.

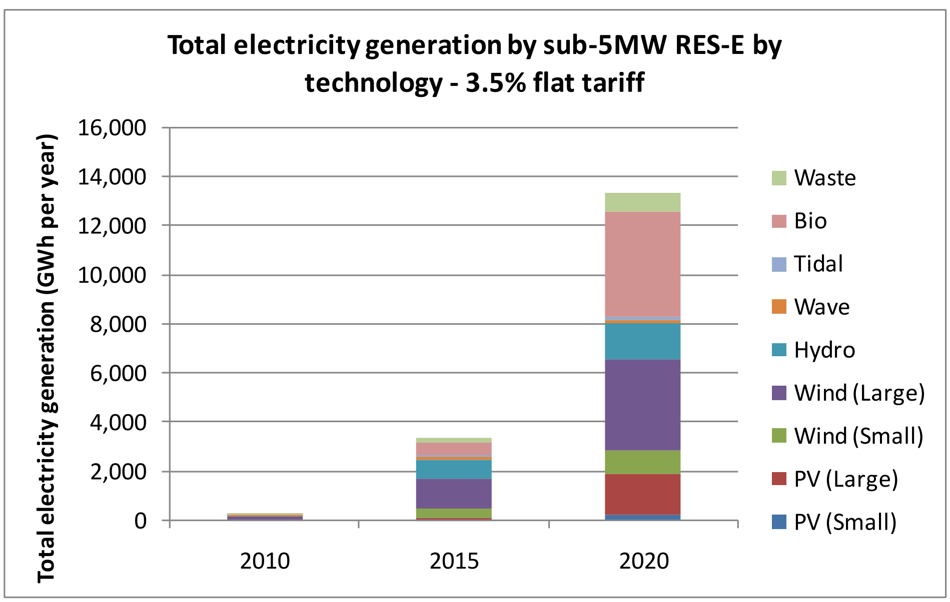


Figure 20 Electricity generation in 2020 - £270 flat tariff

5.2.2 Least cost tariff

The high cost of the small wind and PV systems in the generation mix leads to very high rents being paid to lower cost, large scale projects. Table 17 shows the resource costs and costs to consumers for the 2% and 3.5% least cost runs. A flat tariff of £270/MWh leads to a cumulative costs to consumers by 2020 of £7bn, nearly double the cumulative resource of £3.6 billion. Unlike in the 2% scenario, there is significant scope to reduce these rents through banding since they are primarily caused by cost differences between rather than within technologies. Reducing tariffs for large wind, waste, hydro and biomass CHP as shown in Table 16 reduces the cumulative costs to consumers by £2.5bn to £4.4bn. This is still higher than the cumulative resource costs, with the remaining difference due to rents paid to large wind turbines in windy sites and biomass CHP in low cost stand-alone applications. Table 17 also shows the increased cost per MWh of meeting the target, which is £69/MWh for the 3.5% least cost compared with £36/MWh for the 2% flat tariff.

Table 16 Tariff levels for the 3.5% least cost scenario

Technology	Size	Initial tariff (£/MWh)	Degression (% per year)
PV	Domestic	£280	0%
	4-10kW	£280	0%
	10-100kW	£275	0%
	100-5000kW	£230	0%
	Stand-alone	£200	0%
Wind	Micro	£270	0%
	1-15kW	£270	0%
	15-50kW	£270	0%
	50-250kW	£270	0%
	250-500kW	£240	0%
	500-3000kW	£160	0%
Hydro	1-10kW	£270	0%
	10-50kW	£270	0%
	50-500kW	£270	0%
	500kW+	£200	0%
Wave	All types	£270	0%
Tidal	All types	£270	0%
Biomass	Heat turbine	£190	0%
	ORC	£190	0%
	Steam turbine CHP	£190	0%
	Electricity only	£0	0%
Waste	Electricity only	£100	0%
	AD	£100	0%

	Incineration	£100	0%

Table 17 Comparison of rents in the 2% and 3.5% least cost runs

Parameter	Unit	2% flat tariff	3.5% flat tariff	3.5% least cost
Additional electricity generation in 2015	TWh	1.2	2.3	2.4
Additional electricity generation in 2020	TWh	5.7	11.1	11.4
Renewable heat generation in 2020	TWh	9.1	13.9	14.2
Annual resource cost in 2020	£m	199	844	778
Cumulative resource cost to 2020	£m	1,037	3,538	3,284
Annual resource cost in 2020	£/MWh	35	76	68
Annual cost to consumers in 2020	£m	331	1,613	1,044
Cumulative cost to consumers to 2020	£m	1,523	6,799	4,274
Annual CO2 savings in 2020	MtCO2	2.4	4.8	4.9

5.2.3 Diverse and community scenarios

Although a wide range of technologies is deployed in the 3.5% least cost scenario, uptake of domestic and community-scale systems remains relatively low. For example, the cumulative PV uptake by 2020 at all scales is 2.5GW_e, which is small compared to cumulative uptake of 5GW in Germany since the introduction of the Feed-in Tariff.

In the following scenarios, the policy emphasis is shifted from lowest total cost in favour of encouraging small-scale technology uptake. The diverse scenario encourages greater uptake of high cost technologies at all scales, while the community scenario specifically targets community and domestic installations. Table 18 shows the tariff levels for the two scenarios. Tariffs for PV and small wind are degressed each year to match expected reductions in technology costs and to encourage uptake in the early years of the policy.

Table 18 Tariff levels for the 3.5% diverse and community scenarios

		3.5% diverse		3.5% community tariff	
Technology	Size	Initial tariff (£/MWh)	Degression (% per year)	Initial tariff (£/MWh)	Degression (% per year)
PV	Domestic	£420	5%	£450	5%
	4-10kW	£420	5%	£450	5%
	10-100kW	£350	5%	£370	5%
	100-5000kW	£320	5%	£320	5%
	Stand-alone	£300	5%	£300	5%
Wind	Micro	£300	3%	£300	3%

	1-15kW	£300	3%	£350	3%
	15-50kW	£250	3%	£350	3%
	50-250kW	£165	0%	£180	0%
	250-500kW	£165	0%	£165	0%
	500-3000kW	£165	0%	£150	0%
Hydro	1-10kW	£270	0%	£270	0%
	10-50kW	£270	0%	£270	0%
	50-500kW	£270	0%	£270	0%
	500kW+	£200	0%	£200	0%
Wave	All types	£270	0%	£270	0%
Tidal	All types	£270	0%	£270	0%
Biomass	Heat turbine	£200	0%	£180	0%
	ORC	£200	0%	£180	0%
	Steam turbine CHP	£200	0%	£180	0%
	Electricity only	£0	0%	£0	0%
Waste	Electricity only	£100	3%	£100	3%
	AD	£100	3%	£100	3%
	Incineration	£100	3%	£100	3%

The electricity generating mix for the two scenarios are compared to the least cost run in Figure 21. The diverse scenario results in broadly similar levels of PV uptake as in the least cost scenario, but with a much larger contribution from small systems (less than $100kW_e$). In the flat tariff scenario, the £270/MWh tariff was sufficient to drive significant uptake of 100kW+ PV but only small amounts of domestic-scale systems. In the community scenario, over 3.8TWh of electricity is generated from PV in 2020, from 900,000 domestic and 250,000 small-scale systems. Small wind turbines, excluding building mounted micro machines, are installed in over 40,000 sites and generate 0.8TWh in 2020.

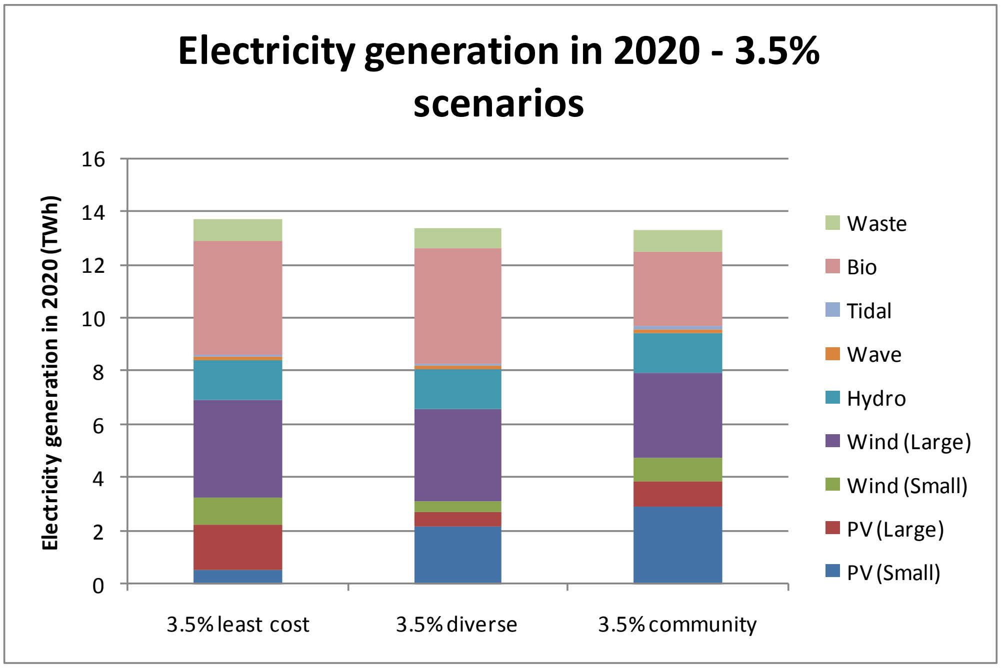


Figure 21 Total electricity generation - diverse and community scenarios

Table 19 shows the cost-benefit analysis outputs for the diverse and community scenarios. Increasing the proportion of PV and small wind in the generating mix significantly increases both the resource cost and cost to consumers. In the diverse scenario the cumulative resource cost to 2020 increases to £5.7 billion compared to £3.3 billion in the least cost scenario, while the community bias increases it further to £6.7 billion. The cost to consumers in 2020 is slightly lower than the equivalent resource cost, implying negative rents. This is due to small-scale systems being purchased by consumers who have lower discount rates than those used in the assessment of resource costs. These negative rents more than offset the positive rents paid to large scale consumers. The annual resource cost per MWh increases to £106 compared with £68 in the least cost scenario. While the main cause of this is the deployment of high cost technologies, it is also due to deployment occurring earlier in the policy lifetime. The additional electricity generated in 2015 (relative to the baseline) is 3.5TWh in the community scenario compared to 2.4TWh in the least cost run.

Table 19 - CBA outputs - diverse and community scenarios

Parameter	Unit	3.5% least cost	3.5% diverse	3.5% community
Additional electricity generation in 2015	TWh	2.4	3.2	3.5
Additional electricity generation in 2020	TWh	11.4	11.1	11.0
Renewable heat generation in 2020	TWh	14.2	14.3	9.4
Annual resource cost in 2020	£m	778	962	1,174
Cumulative resource cost to 2020	£m	3,284	5,769	6,715

Annual resource cost in 2020	£/MWh	68	87	106
Annual cost to consumers in 2020	£m	1,044	1,080	1,159
Cumulative cost to consumers to 2020	£m	4,274	5,639	6,309
Annual CO2 savings in 2020	MtCO2	4.9	4.8	4.7

5.3 Degressed tariffs

As described in Section 5.1.3, the fact that that the tariffs in the least cost scenario remained constant through time causes the majority of deployment to occur in the latter half of the decade. This has the effect of lowering both the resource costs and costs to consumers, since technology costs decrease over time. If one of the aims of the Feed-in Tariff is to stimulate uptake from the start of the policy, tariffs must be set high enough to provide attractive returns for investors even at high technology costs. To prevent excessive rents being paid to investors installing systems in the future, the tariff levels must decrease in line with technology costs. Modifying tariffs over time can be achieved by reviewing the tariffs periodically and lowering them to match the decrease in technology costs that have occurred since the last review. Between the review periods, tariffs could be left unchanged or amended:

- On an ad-hoc basis
- By employing a transparent annual rate of cost reduction such as in Germany, which sets explicit degression rates for each year between review periods.

Although the second method provides investors with certainty over tariff levels, the system is relatively inflexible since it cannot respond to short term economic changes, like increases in technology costs, the inflation rate or the cost of debt, which might affect the level of support required to provide attractive returns. To overcome this lack of flexibility, some EU countries such as the Czech Republic set a ‘floor price’ for each year, so that the tariff will be no less than 95% of the tariff in the previous year. If technology costs rise during the year, the degression rate can be reduced in the following year to prevent a collapse in investor demand.

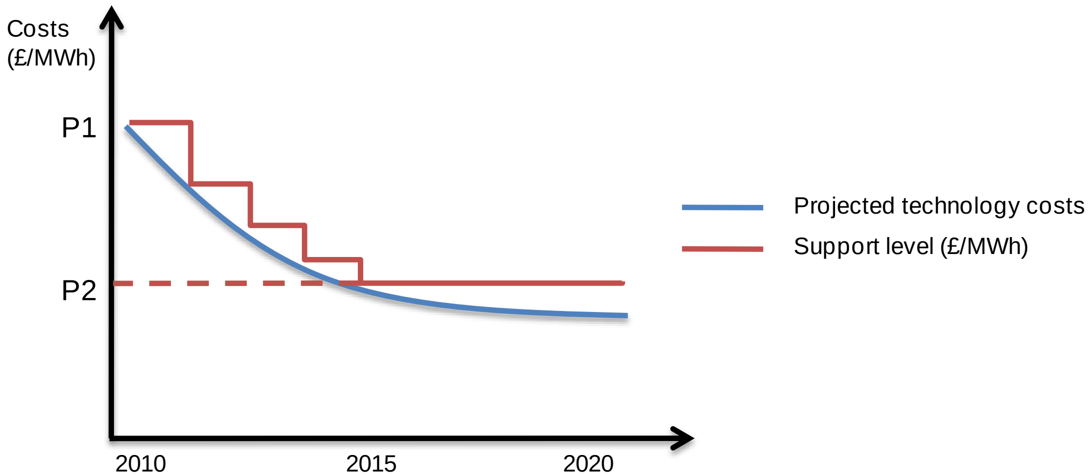


Figure 22 Illustration of degressed versus flat tariffs

Figure 22 illustrates a degressed versus flat tariff for a hypothetical technology. Between 2010 and 2020, the levelised costs of the technology are expected to decrease significantly. A tariff is introduced that is degressed each year to match the cost reductions. The support level is initially set at P1 and decreases to P2 in 2015. The degressed tariff will drive uptake in throughout the policy lifetime since the support level is always higher than the levelised costs. The degressed tariff reduces overall subsidy costs substantially compared to a flat tariff held at P1, since such a tariff would result in large overpayments to investors deploying technologies late in the decade. However, a flat tariff set at P2 results in lower costs because it reduces uptake between 2010 and 2015 when technology costs are high. Increasing the tariff slightly so that it provides returns for a wider range of site types near to 2020 could theoretically deliver the same overall deployment in 2020 at significantly lower costs. The risk from taking this approach in the design of the Feed-in Tariff is that the low demand between 2010 and 2015 fails to drive industry growth and further cost reductions, meaning that the technology cannot be deployed quickly enough in the second half of the decade to meet at 2020 target.

Table 20 Tariff levels for PV- 2% community scenarios with and without tariff degression

		With degression		No degression	
Technology	Size	Initial tariff (£/MWh)	Degression (% per year)	Initial tariff (£/MWh)	Degression (% per year)
PV	Domestic	£400	5%	£300	0%
	4-10kW	£380	5%	£230	0%
	10-100kW	£350	5%	£230	0%
	100-5000kW	£300	5%	£200	0%
	Stand-alone	£300	5%	£200	0%

Table 20 compares the PV tariff levels required for two scenarios that deliver similar technology mixes in 2020. The first is the 2% community scenario described above; the second removes the 5% annual degression for PV and lowers the tariffs so that the overall uptake by 2020 remains the same. As expected, removing degression leads to substantially less uptake by 2015, with 90,000 PV installations compared to 350,000. The cumulative resource costs in 2020 decrease from £4 billion to £2.2 billion. The costs to consumers also decrease from £3.3 to £2.2 billion, and there are no negative rents as were found in the original scenario. This implies that the non-degressed tariffs are sufficient to make PV attractive to a wide range of consumers towards 2020, compared with mainly early adopters in the degressed scenario, so the average hurdle rate of the investors is similar to the 10% discount rate used to assess resource costs.

Table 21 Summary Cost Benefit Analysis outputs - 2% community (no degression)

Parameter	Unit	2% community	2% community no degression
Additional electricity generation in 2015	TWh	2.1	1.4
Additional electricity generation in 2020	TWh	5.6	5.5
Renewable heat generation in 2020	TWh	3.9	3.9
Annual resource cost in 2020	£m	608	527
Cumulative resource cost to 2020	£m	3,924	2,202
Annual resource cost in 2020	£/MWh	109	96
Annual cost to consumers in 2020	£m	506	477
Cumulative cost to consumers to 2020	£m	3,128	2,133
Annual CO2 savings in 2020	MtCO2	2.4	2.4

5.4 Premium tariffs

One of the main distinguishing features between Feed-in Tariffs in European countries is whether the tariffs are paid instead of or in addition to the market electricity price. A fixed tariff pays renewable generators a single price which leads to the transfer of ownership of the electricity to the utility or network operator. In a premium tariff, the generator receives the tariff but retains ownership of the electricity, which is then sold on the open market. A detailed comparison between premium and fixed feed-in tariffs can be found in the report on qualitative design issues prepared by Element Energy and Pöyry. This includes a discussion on the effects on network infrastructure and balancing and settlement costs that are beyond the scope of the model. The analysis here shows the differences between tariff levels for premium versus fixed tariffs.

An important consideration when assessing likely uptake of renewable technologies under the two feed-in tariff types is the attitudes of investors to variable payments versus guaranteed. Discussions with a range of investors conducted by Pöyry as part of this project suggest that investors' hurdle rates are likely to be higher for premium tariffs to reflect the risk of total revenues fluctuating due to variability in the market electricity price over time. The mean increase in hurdle rate based on the discussions was one percentage point. For utilities investing in established technologies such as large-scale wind, the weighted average cost of capital and hence hurdle rate increases from 8% to 9%. It is assumed that this increase applies equally across all investor and technology types in the model.

Table 22 shows the tariff levels for the 2% community scenario for fixed and premium tariffs. These tariffs give similar generation mixes in 2020, as shown in Figure 23. Tariffs for large-scale technologies are £50/MWh lower in the premium tariffs, while small-scale installations receive on average £100/MWh less. The difference between the fixed and premium tariffs is roughly equivalent to the market electricity price paid to the investor. For large-scale technologies which export their entire output to the grid, this is equal to the wholesale price, which varies between £50 and £60 per MWh in DECC's central fuel price estimate. For small-scale technologies whose output is partially used on-site, the average price assumed in the model is the weighted average of the retail and export price. In practice however, due to the fact that small generators provide only small amounts of electricity to the grid, they may have difficulty in securing the same wholesale price for exports that a large-scale generator can access, and may receive a much lower price. As described in Section 3.6, small-scale technologies are assumed to export 50% of their output, while larger systems are assumed to export their entire output to the grid.

Table 22 Tariff levels for the 2% community scenario - fixed and premium tariffs

Technology	Size	Fixed tariff Initial tariff (£/MWh)	Fixed tariff Degression (% per year)	Premium tariff Initial tariff (£/MWh)	Premium tariff Degression (% per year)
PV	Domestic	£400	5%	£300	5%
	4-10kW	£380	5%	£260	5%
	10-100kW	£350	5%	£230	5%
	100-5000kW	£300	5%	£200	5%
	Stand-alone	£300	5%	£200	5%
Wind	Micro	£200	0%	£150	0%
	1-15kW	£300	0%	£250	0%
	15-50kW	£250	0%	£200	0%
	50-250kW	£200	0%	£150	0%
	250-500kW	£180	0%	£130	0%
	500-3000kW	£143	0%	£83	0%
Hydro	1-10kW	£145	0%	£95	0%
	10-50kW	£145	0%	£95	0%
	50-500kW	£140	0%	£90	0%
	500kW+	£140	0%	£90	0%
Wave	All types	£250	2%	£200	2%
Tidal	All types	£250	0%	£200	0%
Biomass	Heat turbine	£130	0%	£80	0%
	ORC	£130	0%	£80	0%
	Steam turbine CHP	£130	0%	£80	0%
	Electricity only	£0	0%	£0	0%
Waste	Electricity only	£100	0%	£50	0%
	AD	£100	0%	£50	0%
	Incineration	£100	0%	£50	0%

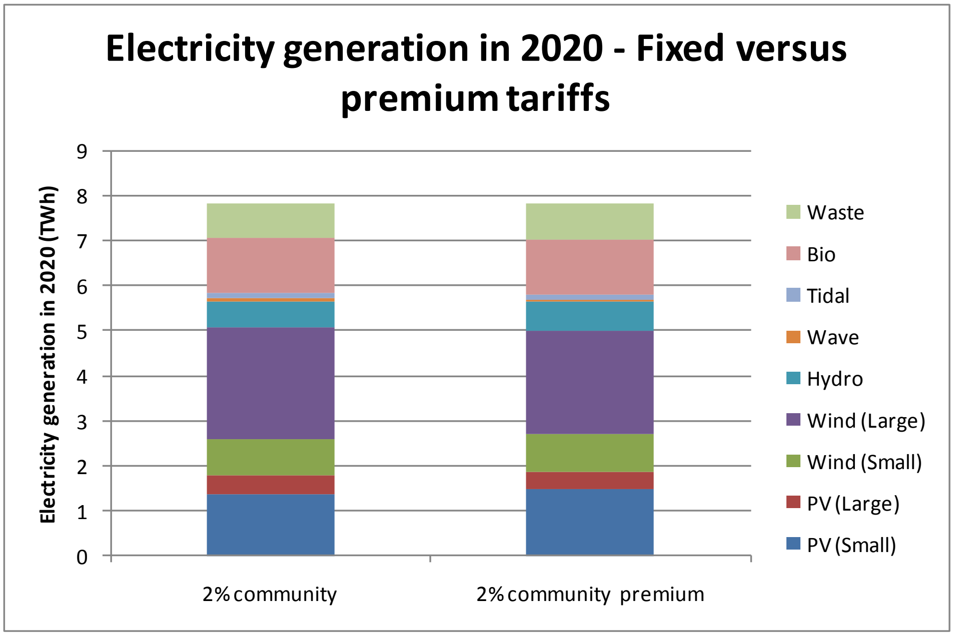


Figure 23 Electricity generation for the 2% community scenario - fixed versus premium tariffs

Table 23 shows the summary CBA outputs for a fixed and premium tariff based on the 2% community scenario. The overall generation in 2020 is similar for the two designs, but the 2015 generation is 0.3TWh lower. This is because in the DECC central fossil fuel price scenario, electricity prices rise between 2010 and 2020. In a fixed tariff design, investors are protected from variation in the electricity price by definition, whereas the total revenue under a premium tariff rises with increases in electricity prices. Degression rates must be modified under premium tariffs since they affect the premium payment rather than the total revenue. For example, if the total revenue was split equally between the tariff and the market electricity rate and the technology cost reduction was 5% per year, the tariff would have to be degressed by 10% at the end of the first year to maintain the same rate of return. In the example given below, degression is not applied to the premium tariff, which delays the deployment of high-cost technologies. This leads to a significant reduction in the cumulative resource cost of £600 million by 2020.

Table 23 Summary CBA outputs - fixed versus premium tariffs

Parameter	Unit	2% community	2% community premium
Additional electricity generation in 2015	TWh	2.1	1.8
Additional electricity generation in 2020	TWh	5.6	5.6
Renewable heat generation in 2020	TWh	3.9	3.9
Annual resource cost in 2020	£m	608	599
Cumulative resource cost to 2020	£m	3,924	3,313

Annual resource cost in 2020	£/MWh	109	108
Annual cost to consumers in 2020	£m	506	572
Cumulative cost to consumers to 2020	£m	3,128	3,052
Annual CO_2 savings in 2020	$MtCO_2$	2.4	2.4

5.5 Effect of tariff lifetime

All of the scenarios above assume that tariff payments are paid for the duration of the project life at the initial rate. For a large wind turbine, this means that tariff payments will be made 20 or 25 years after the system is installed. Since future payments are discounted by approximately 10% per year for an average large-scale investor, the present value of payments made in the 25th year of the project are very low. For example, a Feed-in Tariff payment of £1000 made in year 25 has a present value of only £71 when discounted at 10% per year. This suggests that paying the tariffs over a period shorter than the technology lifetime could significantly reduce the total subsidy required to make the investment attractive for a given consumer. In the extreme case where the tariff was capitalised and paid up front to investors at the time of purchase it could help to overcome the capital cost barriers that may prevent domestic consumers from installing technologies even where the long term rate of return is positive. Deeming and capitalisation of tariffs is discussed in the context of consumer finance below.

Table 24 shows the effect of changing the tariff lifetime on the total subsidy cost. In each case, the present value of the tariff payments to the investor is constant when assessed at a discount rate of 10%. For a tariff of £100 per year paid over 25 years, the present value to the investor is £908 at a discount rate of 10% per year. The present value of the tariff to the government, which discounts future payments at the Green Book discount rate of 3.5%, is £1,648. This assumes that although tariff payments will be passed on to electricity consumers rather than borne by government directly, the social discount rate is still used when assessing the present value of future costs and benefits. If the tariff payment period is reduced from 25 years to 10 years, the annual tariff required to provide the investors with the same overall value is £148. The present value of this higher tariff to government when paid over 10 years is £1,229, 25% lower than for a lifetime tariff. For a tariff paid over five years the difference is even greater and the reduction in total subsidy cost is 34%

Table 24 Effect of tariff lifetime on subsidy costs

	Lifetime tariff	**5 year tariff**	**10 year tariff**	**15 year tariff**
Investor discount rate	10%	10%	10%	10%
Payment period (years)	25	5	10	15
Annual payment (£)	£100	£239	£148	£119
Present value of payments (investor discount rate)	£908	£908	£908	£908
Present value of payments (Green Book discount rate)	**£1,648**	**£1,081**	**£1,229**	**£1,374**

% reduction in lifetime subsidy cost (at Green Book discount rate)	0%	34%	25%	17%

The benefit of reducing tariff lifetimes depends on the importance placed by investors on up-front versus ongoing revenue. The saving in total tariffs paid to an investor is greatest where that investor has a high discount rate. Figure 24 shows the effect of changing consumer discount rates on the cost saving of a 10 year versus 25 year tariff. For an investor with a 10% discount rate, the total value of tariffs paid over a 10 year tariff, when assessed at the social discount rate of 3.5% is £1,230. For a domestic investor requiring very short paybacks and discounting future payments by 20% per year, the total value to the government is only £908. This is a saving of 40% relative to the lifetime tariff. However, for early adopters whose rate of time preference is similar to the social discount rate of 3.5%, there is no benefit to reducing tariff lifetimes. This implies that where domestic systems are purchased primarily by early adopters, there may be limited benefit to paying tariffs over a shorter period.

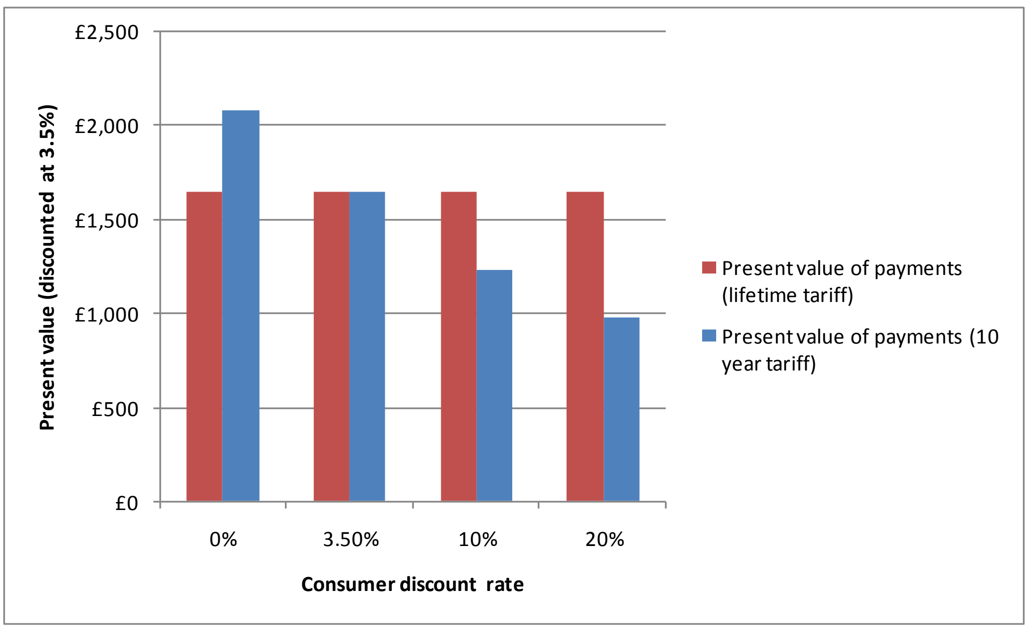


Figure 24 Cost saving of shorter tariff lifetimes at different investor discount rates. The present value of payments is assessed using the social discount rate of 3.5%.

The main advantage of paying tariffs over the lifetime of renewable energy technologies is that is maximises the incentive to maintain the performance of the system for the whole period. Where tariff periods are reduced, or if the tariff is capitalised and paid at the time of purchase, this incentive is reduced. For example, if a fixed tariff was paid over ten years which included payment for the electricity the system would produce over the whole lifetime, the investor would receive no revenue between years ten and twenty five. The investor would then have no incentive pay for maintenance costs, for example a replacement inverter for a PV system, if it occurred after year ten. For this reason, it is suggested that tariffs paid over a period shorter than equipment lifetimes should be premium tariffs, paid on top of the electricity price. While this slightly reduces the benefit in terms of reducing total subsidy costs, it provides a continuing incentive in terms of the market electricity price for maintaining equipment for its useful life.

A special case exists for CHP technologies, where the biomass or gas fuel cost may form a large part of the electricity generating cost. In this case, a premium tariff paid over a short period may not provide incentive to maintain the plant in the long term if the market electricity price alone cannot cover the variable costs of operating it.

5.6 Tariffs based on rate of return

The analysis above shows that different combinations of tariff levels and degression rates can deliver a wide range of technology mixes for a given electricity generation target. This has significant implications for policy costs, and other benefits such as job creation and community engagement. To set tariffs to deliver a certain range of technologies required government to define a number of objectives for the policy, such as the balance between minimising the impact on consumer electricity bills and encouraging domestic consumers to install renewable technologies. An alternative approach to deciding *a priori* what the desired policy outcomes should be is to set tariffs in such a way that they provide an equal rate of return to all technologies at all scales. This allows all technologies to 'compete' for investment on equal terms, and is likely to result in a wide range of technologies being adopted. This is the approach employed by Germany in the design of its Feed-in Tariff, which aims to provide a rate of return of between 5 and 7%.

To simulate this approach, tariffs levels were set to provide a fixed rate of return to all technologies and all scales. For example, to provide an 8% return, the tariffs were set equal to the levelised cost of energy (defined as annual capital repayments and operating costs divided by annual energy production), assessed using a cost of capital of 8%. In addition, tariffs were set to provide equal returns to technologies installed at different sites, so that large wind turbines installed at windy sites receive the same returns as those in less optimal sites. For technologies whose generating costs decrease over time, the tariffs match that reduction to maintain a constant rate of return over time. Note that this approach cannot be implemented in practice since it assumes perfect knowledge of the costs of generation across all technologies, scales and years. In practice, a smaller number of tariffs would be used to provide the desired rate of return to an 'average' installation, and the support received at specific sites may be slightly lower or higher than this amount.

Table 25 shows the fixed tariff levels required to provide a given rate of return to each technology in 2010. Tariffs for wind depend on wind speed and the values in the table assume an annual mean wind speed of 6.5 m/s. The values for biomass CHP are based on the costs of a standalone system rather than one connected to a district heating network.

Table 25 Tariff levels in 2010 (£/MWh) for a range of rates of return

Technology	Size	8%	10%	12%	12% community, 8% large-scale
PV	Domestic	£590	£685	£785	£785
	Medium	£454	£530	£610	£610
	Large	£423	£493	£567	£423

Wind	Micro	£1,000	£1,106	£1,217	£1,217
	Small	£237	£269	£304	£304
	Medium	£151	£170	£190	£151
	Large	£93	£104	£116	£93
Hydro	Small	£240	£274	£311	£311
	Large	£142	£159	£178	£142
Wave	All	£233	£271	£310	£233
Tidal	All	£206	£234	£264	£206
Biomass CHP	Heat turbine	£236	£254	£272	£236
	ORC	£258	£280	£303	£258
	Steam turbine	£185	£198	£212	£185
Waste	All	£90	£100	£110	£90

Figure 25 shows the amount of electricity generated by sub-5MW technologies in four constant rate of return scenarios. In the first three, investors receive a return on investment of 8%, 10% or 12%, independent of technology, size or site type. In the fourth, investors in community-scale technologies receive a higher rate of return of 12%, while large-scale investors receive returns of 8%. For the purposes of this scenario, community scale includes domestic systems and is defined as PV systems with peak power outputs less than 100kW, wind systems less than 250kW and hydro projects less than 100kW.

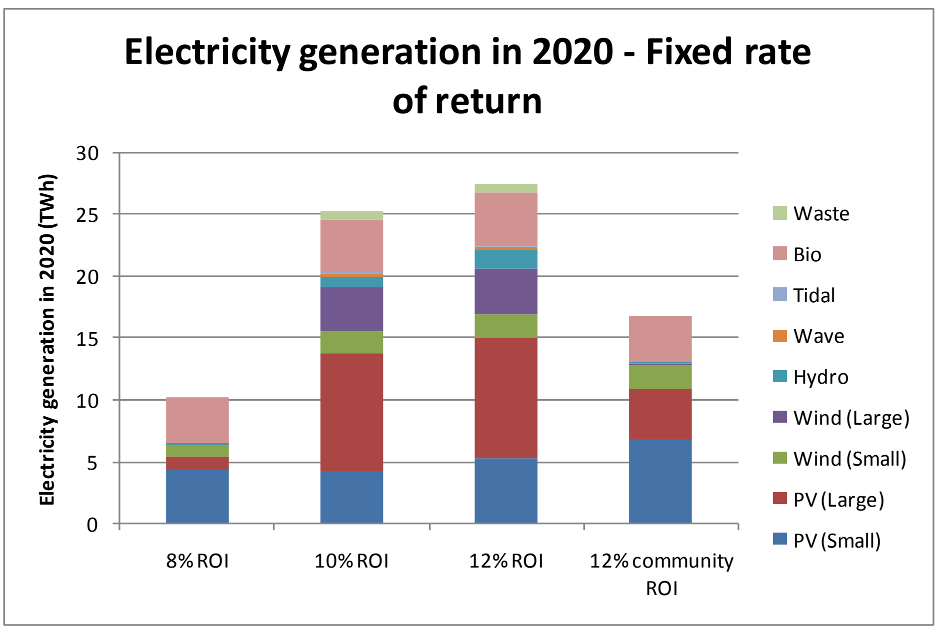


Figure 25 Electricity generation in 2020 - constant rate of return scenarios

At a rate of return of 8%, there is no investment in technologies by developers or utilities since 8% is equal to the minimum point on the hurdle rate distribution for these investors.

Domestic consumers and commercial building owners have minimum hurdle rates of 3% and 6%, respectively, so there is a substantial portion of the population willing to invest at 8%. Over 5TWh of domestic and small-scale PV are installed by 2020, equivalent to 1.7 million installations. Micro-wind turbines are installed in over 800,000 sites, although the tariff required to provide an 8% rate of return is substantially higher than domestic PV, at £1000/MWh. Of the large scale technologies, over 3.5TWh of biomass CHP is installed by 2020. All of these installations are commercial or industrial systems serving heat loads on-site. There is no uptake of district-heating connected systems since these are assumed to be funded only by developers or utilities whose hurdle rates exceed 8%.

Increasing the rate of return to 10% leads to a total electricity generation in 2020 of 25TWh. There is widespread uptake of large scale technologies by developers and utilities, but PV is the dominant technology with nearly 14TWh of generation by 2020. This reflects the very large technical potential of PV, which can be deployed relatively quickly given sufficient economic support. However, over half of the capacity is from installations above 100kW, with 3.5GW of large stand-alone systems installed by 2020. At a rate of return of 10%, most technologies are being deployed at their maximum rate, given supply and demand side constraints. Hence increasing the rate of return to 12% only delivers another 2TWh of generation. A community-based tariff which offers a higher rate of return to community-scale projects as defined above delivers 15TWh of renewable electricity a year in 2020, with over two-thirds of this generated by PV systems.

Table 26 shows the summary cost benefit analysis outputs for the four scenarios. Despite the total electricity generation in the 8% ROI being 3TWh less than in the 3.5% scenarios, the total policy costs are significantly higher than both diverse and community scenarios. This is because there is no contribution from large-scale technologies from developers and utilities at an 8% rate of return, so the generation is exclusively from high cost, small-scale technologies. The resource cost per MWh in 2020 is £204, compared with £110 in the 3.5% community scenario. At a 10% rate of return the cumulative resource cost and cost to consumers are both £12.5 billion, with an annual spend of over £3 billion in 2020. Rents are negligible in the 10% scenario since the rate of return used to set the tariff levels is equal to the discount rate used to assess resource costs, and the tariffs closely match changes in costs across time and different sites. The resource cost per MWh is lower than in the 8% scenario since there is widespread deployment of low-cost, large technologies.

A policy design that offers higher rates of return to domestic and community-scale projects and relatively low rates to businesses has a higher total subsidy cost than a scenario offering 10% returns to all investors, while delivering only 60% of the electricity generation. The cost per MWh is higher for this scenario than if all investors were offered the same 12% rate of return, since the policy has failed to drive uptake of the lowest cost measures.

Table 26 Summary CBA outputs - fixed rate of return scenarios

Parameter	Unit	8% ROI	10% ROI	12% ROI	12% community ROI
Additional electricity generation in 2015	TWh	1.4	3.4	3.8	1.5
Additional electricity generation in 2020	TWh	8.0	23.0	25.2	14.5
Renewable heat generation in 2020	TWh	11.4	7.2	7.5	11.4
Annual resource cost in 2020	£m	1,625	3,233	3,582	2,762
Cumulative resource cost to 2020	£m	8,097	12,552	13,536	10,935
Annual resource cost in 2020	£/MWh	204	141	142	190
Annual cost to consumers in 2020	£m	1,368	3,187	4,195	3,206
Cumulative cost to consumers to 2020	£m	6,848	12,359	15,762	12,593
Annual CO2 savings in 2020	MtCO2	3.4	9.9	10.8	6.2

The analysis above suggests that for a policy design based on offering constant rates of return, trying to minimise resource and policy costs in terms of £/MWh by reducing the rate of return offered will have the opposite effect. This is due to the relatively large number of small-scale consumers who are willing to accept lower rates of return than commercial entities but who only have access to the highest cost technologies. Another significant challenge of this approach is ensuring that all investors receive the intended rate of return, especially for technologies whose costs are highly time- and site-dependent. This requires both degression of tariffs, and a mechanism to minimise rents for low-cost projects while providing a sufficient incentive for those at less optimal sites.

5.7 Interaction between the feed-in tariffs and the Renewable Heat Incentive

In all of the scenarios described above, biomass makes a significant contribution to the electricity generation target. The biomass technologies in the model are all able to operate as electricity only or combined heat and power (CHP) plants, and the design of the feed-in tariff is critical in determining whether waste heat from the plants is utilised. Electricity-only plants are likely to have significantly lower costs per MWh_e than CHP plants due to the cost of connection to a heat distribution network, either within a building or between buildings in the case of district heating. In addition, extraction of heat from a steam cycle reduces the electrical efficiency of the plant, which leads to lower feed-in tariff revenues for a given fuel input.

Despite lower costs, electricity-only biomass plants are an inefficient use of the biomass resource compared to CHP plants, which have overall efficiencies of over 70%. Due to the nature of the turbines used in sub-5MW plants, the electrical efficiency is significantly lower than in a gigawatt-scale fossil fuel power station. In other words, if the biomass resource is to be exploited solely for the production of electricity, it should be co-fired in large centralised plants (at 40% efficiency), rather than in decentralised electricity-only plants with an efficiency of only 25-30%.

At current technology costs, the additional expense in utilising waste heat from a biomass plant is not recouped through heat sales over the life of the plant. This is especially true if the costs of consumer connections to a district heating network are included in the project cost. This means that a feed-in tariff offering the same support to biomass technologies whether or not the waste heat is utilised will encourage deployment of electricity-only plants. If this is to be avoided, the policy must be designed to provide additional revenue to CHP plants. This can be achieved in the following ways:

1. Excluding electricity-only biomass from the list of technologies eligible to receive the feed-in tariff. Sub-5MW plants will remain eligible for support under the Renewables Obligation.
2. Setting support levels so that plants utilising waste heat receive a higher tariff. This is delivered through the feed-in tariff, so each MWh of *electricity* is rewarded more highly by CHP plants.
3. Setting equal tariffs for plants irrespective of heat use and providing an additional incentive for heat use through the Renewable Heat Incentive. The feed-in tariff is set at such a level that it doesn't provide attractive returns to plants without the RHI support, thus minimising deployment of electricity-only plants.

Method 2 is similar to the support provided to biomass under the Renewables Obligation, where plants receive an additional 0.5 ROCs subject to meeting criteria on the use of waste heat. For plants with a heat to power ratio of three to one and at a ROC price of £45/MWh, this support is equivalent to £7.50 for each MWh of heat delivered.

For simplicity, electricity-only biomass is specifically excluded from the main model runs described above. These plants receive revenue equivalent to the market electricity price plus 1 ROC. CHP only biomass receives the Feed-in Tariff as well as a Renewable Heat Incentive for each MWh of heat delivered. The value of the RHI is £10/MWh_{th}, and is assumed to remain constant throughout the life of the policy. This is similar to the premium of 0.5ROCs per MWh offered to biomass plants under the banded Renewables Obligation. The level is chosen to illustrate Method 3 above, and does not reflect the Government's position on support levels under the Renewable Heat Incentive. For simplicity, biomass plants receive the same heat incentive whether the heat is used on-site or fed in to a district heating system.

Table 27 shows the effect of offering a Feed-in Tariff to electricity-only biomass. In the first scenario, a Feed-in Tariff of £155/MWh_e is offered to all biomass CHP plants, regardless of technology type or site. A further £10/MWh_{th} is offered in the model under the Renewable Heat Incentive. Electricity-only biomass does not receive support under the FIT. There are nearly 1,900 CHP plants installed by 2020 under this scenario, generating 2.8 TWh of electricity, and no uptake of electricity-only plants. In the second scenario, electricity-only biomass is offered a fixed feed-in tariff of £155 per MWh_e, the same as biomass CHP, while in the third scenario the electricity-only tariff is lowered to £120/MWh. A £155/MWh is sufficient to make electricity-only plants an attractive investment, with 88 3MW_e installed by 2020. Providing a tariff to electricity-only plants reduces uptake of CHP plants over the policy lifetime. This is due to the fact that the overall uptake of biomass technology is constrained by maximum growth rate of the industry. This leads to some of the market capacity being 'allocated' to electricity-only projects, which provide attractive returns and do not share the same heat demand constraints with CHP plants.

Table 27 Biomass electricity scenarios

	2% flat tariff	£155/MWh for biomass electricity	£120/MWh for biomass electricity
Cumulative installations by 2020 (CHP)	1,878	648	1,082
Cumulative installations by 2020 (elec. only)	0	88	53
GWh generated in 2020 (CHP)	2,833	995	1,718
GWh generated in 2020 (elec. only)	0	1,839	1,116

Reducing the biomass-electricity tariff to £120/MWh, while maintaining support for CHP plants at £155/MWh, causes CHP plants to be the dominant biomass technology in 2020, with 1.7TWh of electricity generated compared to 1.1TWh from electricity-only plants. In this scenario, the difference in support between CHP and electricity-only plants is £35/MWh_e from the Feed-in Tariff plus £10/MWh_{th} from the RHI. The total difference in support for a steam turbine (with a heat to power ratio of 2.5 to 1) is £60/MWh_e. This suggests that the extra half ROC available to CHP plants under the RO is not sufficient to discourage the installation of electricity-only plants in the majority of applications. This assumes that the entire cost of heat distribution is borne by the CHP project developer. If the costs of heat networks, particularly for district heating, were reduced by another policy mechanism such as low cost loans or grants, this would reduce the amount of support required for the plant under the FIT or the RHI.

5.8 Gas-fired CHP

In addition to providing support to renewable electricity technologies, the Feed-in Tariff will provide a tariff to gas-fired CHP with peak capacities up to 50kW$_e$. Although not strictly a renewable technology, good quality gas CHP offers significant CO_2 reductions relative to gas boilers and grid electricity due to higher overall efficiencies. The costs of gas-fired CHP are highly site-specific, and 50kW$_e$ systems in high run hours locations can already be economically attractive under current policies and fuel prices. However, at the domestic scale, Stirling engines and fuel cells are not yet available in commercial quantities and capital costs are significantly higher than the incumbent condensing boiler.

Since domestic CHP systems are currently under development and not yet available in commercial quantities, there is considerable uncertainty over the long term costs, as well as CO_2 savings, of these technologies. The results below show the costs of widespread CHP uptake, under the assumption that costs decrease in line with industry expectations (as shown in Appendix 1).

Table 28 shows the uptake of gas-fired CHP under the baseline, which does not include explicit support for the technology. Systems are assumed to receive the wholesale electricity price for power exported to the grid, and on-site consumption is valued at the relevant import price. Overall uptake by 2020 is low for all technologies, with fewer than 2,000 commercial systems installed. Fuel cell CHP is installed in over 140,000 homes, with over 70% of this uptake occurring in 2019 and 2020. Due to its relatively low electricity generation, Stirling engines do not provide attractive returns to domestic consumers without additional policy support[8].

Table 28 Gas-fired CHP uptake under the baseline

Technology	Cumulative installations in 2020	MW installed capacity in 2020	GWh electricity generated in 2020
Stirling	0	0	0
Fuel cell	146,835	147	730
10kW gas	855	9	51
50kW gas	990	49	297

[8] It should be noted that these results differ slightly from the baseline results in the 2008 Element Study on the Growth Potential for Microgeneration. The baseline in that model included support from electricity suppliers under CERT and the post-2011 supplier obligation, which is critical in ensuring uptake between 2010 and 2020 while technology costs decrease. The model developed for that study also includes a large number of building types to provide a better representation of the UK building stock. The consumer behaviour model in that study is also more suitable for domestic consumers, since it allows consumers to 'choose' between competing technologies such as gas boilers, heat pumps and biomass systems. Readers seeking a more detailed analysis of domestic scale CHP are referred to that report, available at http://www.berr.gov.uk/energy/sources/sustainable/microgeneration/research/page38208.html

Total	148,680	148,680	148,680

In the following scenarios, a fixed feed-in tariff was applied to all gas-fired CHP. The tariffs are differentiated by technology but not site type, so a fuel cell installed in a new build home receives the same support per MWh of electricity as one installed in an older property. In the first scenario a flat tariff of £155/MWh is offered to gas-CHP. When the same tariff is offered to all sub-5MW renewables, as described in Section 5.1.1, approximately 8TWh of generation is delivered by 2020. Table 29 shows uptake of gas-fired CHP under the fixed tariff. The tariff delivers 5 million CHP systems by 2020, with nearly 2.5 million units each for Stirling engines and fuel cells. The total generating capacity is nearly 6GW, producing 22TWh of electricity in 2020. This is equivalent to over 5% of projected UK electricity demand in that year.

Table 29 Uptake of gas-fired CHP under a £155 fixed tariff

Technology	Cumulative installations in 2020	MW installed capacity in 2020	GWh electricity generated in 2020
Stirling	2,452,503	2,453	7,261
Fuel cell	2,449,104	2,449	11,749
10kW gas	41,537	415	1,708
50kW gas	11,083	554	1,919
Total	4,954,226	5,871	22,637

The summary CBA outputs for the flat tariff are shown in Table 30. The total electricity generation relative to the baseline increases from 3TWh in 2015 to 21.6TWh in 2020, suggesting that the majority of uptake occurs in the second half of the decade. The cumulative resource cost in 2020 is nearly £5 billion, but the cost per MWh of £61 is significantly lower than scenarios involving widespread deployment of domestic scale renewables, where the resource cost can exceed £100/MWh. The cumulative cost to consumers is £1 billion lower than the cumulative resource cost, suggesting significant negative rents. This is because although 5 million domestic CHP units is a high number, it is only 25% of the total suitable housing stock. This means that consumers with relatively low hurdle rates (lower than the 10% cost of capital employed in the cost benefit analysis) are making the majority of the investments. The annual CO_2 savings of 3.3Mt in 2020 includes an allowance for the carbon content of the gas input.

Table 30 Summary CBA outputs - £155/MWh flat tariff for CHP

Parameter	Unit	Value
Additional electricity generation in 2015	TWh	3.0
Additional electricity generation in 2020	TWh	21.6
Renewable heat generation in 2020	TWh	0.0

Annual resource cost in 2020	£m	1,327
Cumulative resource cost to 2020	£m	4,784
Annual resource cost in 2020	£/MWh	61
Annual cost to consumers in 2020	£m	1,103
Cumulative cost to consumers to 2020	£m	3,889
Annual CO2 savings in 2020	MtCO2	3.3

The levelised cost of electricity from medium-scale CHP is expected to remain relatively constant over time, since reciprocating gas engines are a mature technology with a large installed base. However, costs of Stirling engines and fuel cells are expected to decrease substantially as manufacturing techniques improve and supply chains mature. For example, the levelised cost for fuel cell CHP in a high run hours application decreases from £277/MWh_e in 2010 to £135/MWh_e in 2020. This suggests that a tariff with a built in degression rate would lead to increased uptake in the early years of the policy without causing large rents as costs decline towards 2020. Table 31 shows a possible degressed tariff for Stirling engines and fuel cells. At a degression rate of 5% per year, an initial tariff of £240/MWh_e decreases to £144/MWh in 2020.

Table 31 Degressed tariff levels for gas-fired CHP

Technology	Degression rate	Tariff in 2010	Tariff in 2015	Tariff in 2020
Domestic Stirling	5%	£240	£186	£144
Domestic Fuel Cell	5%	£240	£186	£144
Gas Engine (10kW)	0%	£155	£155	£155
Gas Engine (50kW)	0%	£155	£155	£155

The summary CBA outputs for the flat and degressed tariffs are compared in Table 32. The main conclusion is that paying higher tariffs at the beginning of the policy does not result in more installations by 2015. This is because the industry is already growing at its maximum rate under the flat tariff. Fuel cell CHP is not expected to be widely available before 2011-12, so in 2015 the maximum number of installations is only 100,000 even at high tariffs. A similar constraint exists for Stirling Engines.

Although the deployment profile and hence generation and resource cost figures look similar for the flat and degressed tariffs, the cumulative cost to consumers by 2020 is over £1 billion higher for the degressed tariff. This suggests that for novel technologies whose initial uptake is heavily constrained on the supply side, there is no benefit to paying higher tariffs in the early years of the policy. As long as the lower tariff still leads to sufficient investors to allow the industry to grow, paying high tariffs will not deliver any additional deployment even though the number of willing investors increases. This means that the higher tariffs are simply rents for the investors who would have been willing to invest at a lower level of support.

Table 32 Summary CBA outputs - degressed tariffs for small CHP

Parameter	Unit	Flat tariff	Degressed tariff
Additional electricity generation in 2015	TWh	3.0	3.0
Additional electricity generation in 2020	TWh	21.6	21.2
Renewable heat generation in 2020	TWh	0.0	0.0
Annual resource cost in 2020	£m	1,327	1,313
Cumulative resource cost to 2020	£m	4,784	4,877
Annual resource cost in 2020	£/MWh	61	62
Annual cost to consumers in 2020	£m	1,103	1,166
Cumulative cost to consumers to 2020	£m	3,889	4,738
Annual CO2 savings in 2020	MtCO2	3.3	3.2

The result described above would support setting a flat tariff for CHP for the first few years of the policy. The tariff would be set so that it provides attractive returns only to a limited pool of investors, and technology cost reductions would increase the number of investors in line with the ability of the industry to meet the demand. As well as creating maximum certainty for the industry, this approach eliminates the need to set an explicit degression rate for a novel technology whose cost reduction rate is highly uncertain. Once the technology reaches meaningful levels of deployment, the tariff levels can be reviewed and an annual degression rate set to reflect further reductions in the system costs. Although a feed-in tariff is likely to be the best option for driving widespread deployment of micro-CHP in the medium to long term, the technology may benefit from alternative or additional support during the early stages of commercialisation. Such support could include grant funding under a post-2011 Supplier Obligation, or an alternative programme. Grant support paid upfront would help consumers to overcome the high capital cost barrier that is likely to be present for early systems. Once capital costs have decreased, a Feed-in Tariff would then provide a continuing incentive for high-performance systems that generate significant quantities of electricity each year.

6 Conclusions

The analysis suggests that there is a very large technical potential of sub-5MW renewable electricity in the UK. The total resource is 130 TWh per year, with PV and biomass CHP contributing over 100TWh to this target. There is also a very large sub-50kW gas-fired CHP resource of nearly 90TWh per year. Taken together, this potential is equivalent to nearly half of UK electricity generation. The majority of this potential is not currently economic and cannot be delivered without large subsidies. When additional market and social barriers are considered, the actual potential that can be delivered each year is much lower, but still represents a meaningful contribution to UK electricity supply. A tariff design that encourages uptake across a range of technologies and scales can deliver 10-15TWh per year of renewable electricity in 2020, with an additional 20TWh from sub-50kW gas CHP.

The other main conclusions from this study are as follows:

- A 2% generation target can be achieved at relatively low cost using mega-watt scale technologies. The cumulative resource cost by 2020 is £1.0 billion higher than business as usual. Diversifying the technology mix to include domestic-scale PV and wind comes at a high cost, with the cumulative resource cost in 2020 increasing to £4 billion.

- For a policy aiming to drive uptake of a wide range of technologies, setting a flat tariff leads to significant over payments to low-cost large scale generators. Banding tariffs by technology can lead to significant reductions in subsidy costs while maintaining the same overall generation. The importance of banding increases with increasing technology diversity, since the differences in costs between technologies becomes larger than differences within technologies (for example large wind turbines at different wind-speed sites).

- Increasing the generation target to 3.5% of the UK electricity demand significantly increases the cost to the country by 2020, from £1 billion to £4 billion for the least cost scenarios. A 3.5% least cost scenario results in significant uptake of small-scale technologies, with over 3TWh of electricity per year generated from PV and small wind. This is because for ambitious targets, large-scale technologies cannot be deployed quickly enough to meet the target by 2020.

- For technologies whose costs are expected to decrease over time, reducing tariff levels each year is necessary to avoid overpayments to investors making investments in the second half of the next decade. However, matching tariff levels to technology costs from the first year of the policy results in significantly higher policy costs than setting a flat tariff so that the technology is only deployed when its costs decrease. In other words, there is a financial benefit to delaying uptake until technologies are cheaper. The risk of this approach is that if consumer demand is low for the first few years of the policy, the industry will not make the investments necessary to deliver large amounts of renewable energy at low cost towards 2020.

- Premium tariffs, where tariff payments are made on top of the market electricity price, carry a higher risk than a fixed tariff with an equivalent total support level, due to volatility of electricity prices. This additional risk is likely to be reflected in a higher cost of capital for projects and higher hurdle rates. This means that overall support must be higher under a premium tariff to encourage a given level of uptake.

- In the results above, it is assumed that tariffs are paid over the lifetime of the technology. Where investors employ high discount rates and place a low financial value on revenues received in the distant future, total subsidy costs can be significantly reduced by paying tariffs over a shorter period. For example, for an investor with a 10% discount rate, a 10 year tariff that provides the same perceived value as a 25 year tariff has a 25% lower lifetime subsidy cost (assessed at the social discount rate of 3.5%).

- The benefit of paying tariffs over a shorter period is highly sensitive to the way in which investors value long term benefits. For an early adopter with a similar discount rate to the social discount rate, there is no benefit to paying tariffs over a shorter period. For investors with very high discount rates, such as many domestic consumers, costs can be reduced by paying tariffs up-front at the point of purchase (capitalisation). The risk of this approach is that the investors has less incentive to continue to operate the system after the majority of the tariff has been paid. In addition, capitalisation requires the energy output of each system to be 'deemed' (estimated), and would require additional verification that the device actually delivered the electricity that it was predicted to do.

- Setting tariffs to provide an 8% rate of return for all technologies encourages uptake of small-scale, higher cost technologies but does not stimulate deployment of large-scale systems. This is because there is a significant proportion of domestic investors who are willing to accept returns of 8% or less, but the majority of large-scale investors have hurdle rates above 8%.

- The treatment of electricity from biomass must be considered carefully in the design of the Feed-in Tariff. A tariff structure that fails to provide additional incentives for plants utilising waste heat is likely to encourage the construction of electricity-only plants. This is an inefficient use of biomass compared to CHP plants and co-firing in gigawatt-scale electricity plants. A premium of £10/MWh_{th}, similar to the additional 0.5 ROCs per MWh_e paid to CHP plants under the RO, is sufficient to encourage use of waste heat in on-site applications. However, higher support is required to encourage deployment of plants connected to district heating networks due to the high additional costs involved. This higher support could be provided through the Feed-in Tariff, the Renewable Heat Incentive, or other policy support such as low-cost finance or grants for the construction of the heat distribution networks.

- There is a very large potential for gas-fired CHP available at relatively low cost. A flat tariff of £155/MWh, equivalent to the market electricity price plus the 2 ROCs per MWh currently paid to renewable microgenerators, delivers nearly 22TWh of CHP electricity by 2020. The annual CO_2 savings from gas-fired CHP in that year are over 3 million tonnes. However, the majority of this potential is from domestic-scale devices which are not currently available in commercial quantities. As a result there is some uncertainty over the long term costs of these technologies.

- A flat tariff of £155/MWh for gas-fired CHP has significantly lower subsidy costs than an initial tariff of £240/MWh degressed at 5% per year. This is because uptake is initially constrained by the ability of the industry to ramp up production capacity. Paying higher initial tariffs results in overpayments to investors who were willing to invest with lower support levels, while failing to deliver any additional deployment. This supports holding tariffs at the same level for the first few years of the policy, before introducing degression to match any further cost reductions.

7 Appendix A - Technology cost and performance assumptions

Technology cost projection assumptions form a key input into the Feed in Tariff model. This appendix outlines proposed costs for the period 2009–2030.

Approach to technology costing

For smaller systems, the technology capital costs are represented using fixed and marginal elements. The fixed value is capacity independent and represents fixed costs per installation site. The marginal element is size dependent based on £/kW. When sizing systems, this allows for size independent elements (e.g., electrical installation) to be costed separately from size dependent (e.g. PV area), as illustrated in Figure 26.

Fixed costs are typically a high percentage of the overall costs where small one-off systems are installed. For larger systems, technology capital costs have simply been represented as a cost per kW installed.

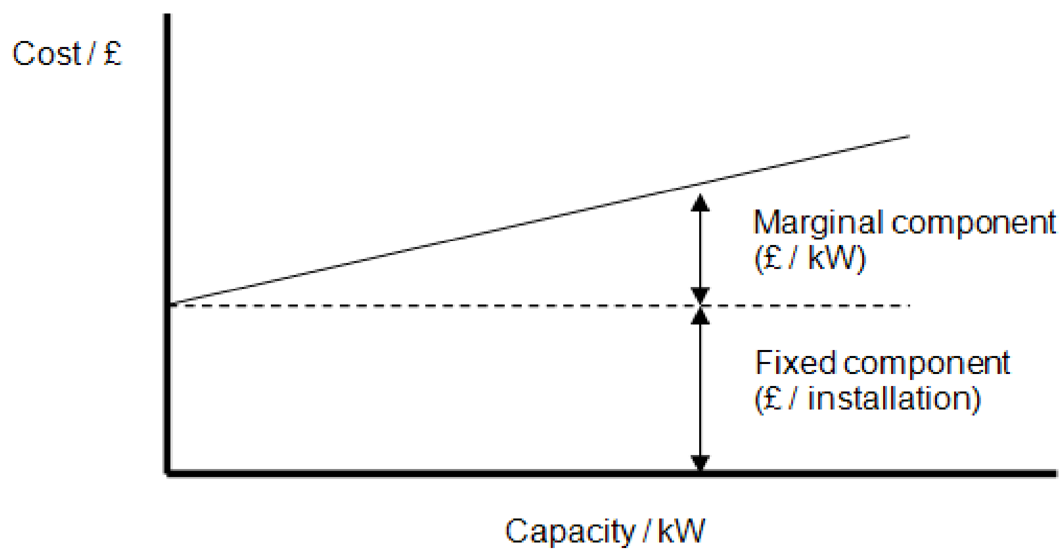


Figure 26 Representation of fixed and marginal costs

For any given technology, in any year, costs will vary with size of installation. Over time technologies are also predicted to experience a learning rate, which relates growth (or cumulative capacity) with a set percentage reduction in cost. For many technologies, the learning curve methodology theory has been realised in practice. For example, historical PV costs follow a learning rate of 18%. This means that every doubling of capacity/production is accompanied by an 18% reduction in capital cost.

Where significant reductions in capital cost are predicted, these projections are based on learning curve analysis, details of which can be found in the original BERR Microgeneration Study appendices and the Potential for Microgeneration: Study and Analysis.[9]

Inflation is considered to be 0% throughout the study for simplicity. The incumbent is assumed to be the national grid unless otherwise stated.

Maintenance costs

Maintenance costs may increase or decrease depending on wage rates, the uptake of technologies (and therefore number of local installers) and the maturity of technology; for example, whilst technology maturity may reduce costs, this could be countered by increasing rates due to skills shortages.

Feedback effects

It is recognized that there are a number of feedbacks which are likely to impact the cost of a particular technology in the UK. For example, an increase in UK installed capacity may lead to an improvement in installation methods or more skilled installers, driving down the total cost, which in turn may increase sales further.

Cost reductions for the technologies themselves are likely to be linked to the global market, since the UK is a relatively small proportion of global demand. However, costs associated with installation are likely to be driven more strongly by UK demand. An additional distinction is made between time-dependent and volume-dependent learning rates.

Exchange rate

The exchange rate between Euros, pounds and dollars, is a key variable and leads to uncertainties in future cost projections. Where costs have been provided in Euros or dollars, the following exchange rates have been used:

GBP	1.0
Euros equivalent	1.1
US Dollars equivalent	1.5

Costs converted from their original currency are marked with an asterisk.

Interest rates

Interest rate variability is another key variable. For this study, interest rates will aim to look at the medium rather than short term picture.

[9] Potential for Microgeneration: Study and Analysis. Energy Saving Trust, Element Energy, EConnect. 2005.

Cost data inclusions/exclusions

The costs given in this document represent total installed cost for the given technology, including design, plant acquisition, delivery, installation and commissioning, unless otherwise stated. **All costs are quoted before VAT.**

7.1 PV

Key parameters

Parameter	Value	Comments
Load factor	850 kWh / kWp.yr	850 kWh / kWp is typical for well orientated UK PV installations.
Technology lifetime	25 years	Some PV manufacturers suggest that systems may last significantly longer than this. However, degradation leads to reduced output over time and a 25 year lifetime is taken as a conservative estimate.

Current technology costs

2009			
System size/type	**Fixed cost (per site)**	**Marginal cost (£/kW)**	**Annual maintenance cost**
New build domestic (2.5kWe)	£1,500	£3,983	£110
Retrofit (2.5kWe)	£2,000	£4,500	£110
New build (4-10kW)	£4,800 per kW		£24.00 per kWe
Retrofit (4-10kW)	£4,800 per kW		£24.00 per kWe
New build (10–100kWe)	£4,300 per kW		£22.00 per kWe
Retrofit (10–100kWe)	£4,300 per kW		£22.00 per kWe
New build (100–5,000kWe)	£4,000 per kW		£20.00 per kWe
Retrofit (100–5,000kWe)	£4,000 per kW		£20.00 per kWe
Stand alone system	£4,000 per kW		£20.00 per kWe

Capital costs for small systems are based on a new build system price c. £5,200 for a 1kW system in 2009.[10]

- Retrofit costs are slightly higher due to costs of scaffolding and wiring at £6,500 for a 1kWp system and £11,000 for a 2kWp system.
- The fixed costs include mechanical and electrical installation, which are independent of system size and will not be subject to the cost reductions of the PV panels.

[10] System costs circa £5,200/kW have been provided by UK installers. This represents a conservative view and lower costs can be achieved.

- For larger systems, the cost of the solar cells makes up a significant portion of the overall system cost, which means that total cost scales approximately linearly with power output.
- Building integrated PV solutions in new build gain an offset benefit of the order £500 per kWp (i.e. benefit from the fact that PV tiles replace standard tiles). The net cost of building integrated solutions depends on the type of PV system, for example whether it is a laminate or double glazed. Feedback from industry suggests that an average cost of building integrated PV laminate systems is around £5,500 per kWp, while the figure for double glazed systems is c.£6,000 per kWp.
- Maintenance costs for the smaller systems are based on a professional electrical check and clean every five years taking half a day. An additional £1,000 every 15 years is also included in this cost to allow for inverter replacement.[11]

Technology cost projections

Cost projections allow for a significant reduction in cell cost through technical evolution and material supply improvements. During 2007 and 2008, for example, increased availability of silicon enabled large reductions to be realised.

The PV market is global, and therefore sales to the UK alone are unlikely to significantly influence the future price of PV. It has, however, been noted that some costs for PV (in particular installation) are likely to decrease as the cumulative UK installed capacity grows.

2015			
System size/type	**Fixed cost (per site)**	**Marginal cost (£/kW)**	**Annual maintenance cost**
New build (<10kWe)	£1,500	£2,240	£110
Retrofit (<10kWe)	£2,000	£2,530	£110
New build (4-10kW)	£2,699 per kW		£16.00 per kWe
Retrofit (4-10kW)	£2,699 per kW		£16.00 per kWe
New build (10–100kWe)	£2,420 per kW		£15.00 per kWe
Retrofit (10–100kWe)	£2,420 per kW		£15.00 per kWe
New build (100–5,000kWe)	£2,250 per kW		£14.00 per kWe
Retrofit (100–5,000kWe)	£2,250 per kW		£14.00 per kWe
Stand alone system	£2,250 per kW		£14.00 per kWe

2020			
System size/type	**Fixed cost (per site)**	**Marginal cost (£/kW)**	**Annual maintenance cost**
New build (<10kWe)	£1,500	£1,759	£110
Retrofit (<10kWe)	£2,000	£1,987	£110
New build (4-10kW)	£2,120 per kW		£15.00 per kWe
Retrofit (4-10kW)	£2,120 per kW		£15.00 per kWe
New build (10–100kWe)	£1,900 per kW		£14.00 per kWe

[11] According to a UK industry source, replacement inverters may be required every 15 years.

Retrofit (10–100kWe)	£1,900 per kW	£14.00 per kWe
New build (100–5,000kWe)	£1,765 per kW	£13.00 per kWe
Retrofit (100–5,000kWe)	£1,765 per kW	£13.00 per kWe
Stand alone system	£1,765 per kW	£13.00 per kWe

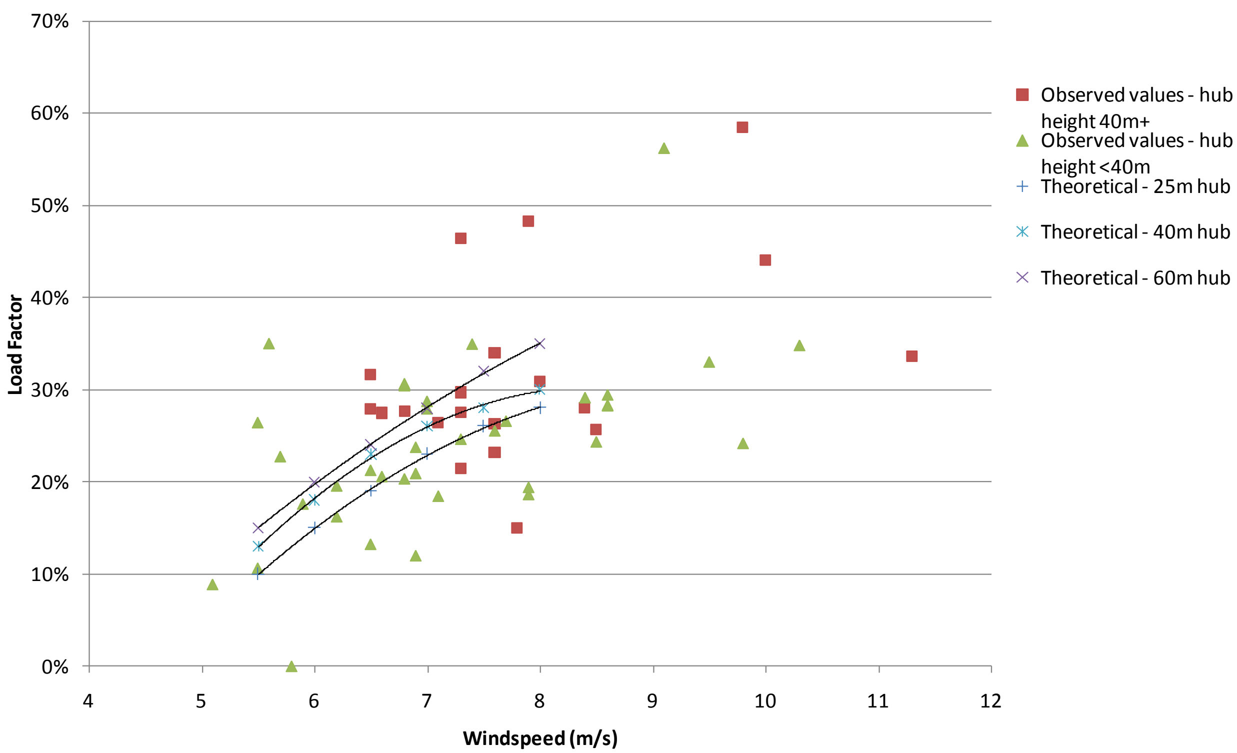
7.2 Wind

Key parameters

The energy output of a wind turbine is highly dependent upon wind speed, which increases with increasing height above the ground. Access to masts and towers, where the hub height can be increased, therefore greatly improves wind turbine performance.

The graph below shows the performance of different installed systems across the UK. Observed values are based on data from a Renewable Energy Foundation report which analysed monthly records of load factors (Ofgem data) and have a range of associated hub heights from 25 to 65m. [12] Observed load factors recorded here are based on an average of monthly load factors over a one year period.

A comparison between assumed and observed load factors at varying windspeed for turbines in the 50kW–1.5MW range



[12] UK Renewable Energy Data: Issue 1 (08.12.06): Vol. 5: Wind. 1/168, researched by Oswald Consultancy Ltd.

The measured data shows that a large degree of scatter about the theoretical load factors is observed. The following load factors are proposed for this study.

Size	5.5 m/s	6 m/s	6.5 m/s	7 m/s	7.5 m/s	>8.0 m/s
B-M <1.5kW urban	2%	2%	2%	2%	2%	2%
B-M <1.5kW rural	8%	8%	8%	8%	8%	8%
Mast mounted micro (urban)	2%	2%	2%	2%	2%	2%
Mast mounted micro (rural)	8%	10%	12%	13%	13%	14%
1.5–15kW urban	7%	7%	7%	7%	7%	7%
1.5–15kW rural	15%	15%	19%	23%	23%	26%
15–50kW urban	7%	7%	7%	7%	7%	7%
15–50kW rural	15%	15%	19%	23%	23%	26%
50–250kW	10%	15%	19%	23%	23%	26%
250–500kW	13%	18%	23%	26%	26%	28%
500–3000kW	15%	20%	24%	27%	28%	32%

Summary of key parameters:

System size/type	Load factor	Technology lifetime	Typical hub height
Micro (<1.5kW)	8% rural	10 years	2m above building
1.5–15kW	Dependent on windspeed and hub height	15 years	10 m
15–50kW	Dependent on windspeed and hub height	15 years	15m
50–250kW	Dependent on windspeed and hub height	20 years	25m
250–500kW	Dependent on windspeed and hub height	20 years	40m
500–3,000kW	Dependent on windspeed and hub height	20 years	60m

Current technology costs

2009			
System size/type	**Fixed cost (per site)**	**Marginal cost (£/kW)**	**Annual maintenance cost**
Micro (<1.5kW)	£3,500	£2,000	£110
1.5–15kW	£10,000	£2,000	£220
15–50kW	£3,000 total per kW		£74 per kW

50–250kW	£3,000 total per kW	£74 per kW
250–500kW	£2,500 total per kW	£61 per kW
500–3,000kW	£1,500 total per kW	£44 per kW

- A capital cost of £5,500 is assumed for a retrofit 1kW turbine (building integrated). [13]
- Capital costs for tower-mounted micro-wind for a typical installation range from c. £15,000 for a 2.5kW system to £22,000 for a 6kW system. The installation cost is a significant portion of the total cost at this scale. The capital cost of these installed turbines is relatively insensitive to capacity, and strongly based on electrical and mechanical installation and size-independent hardware.
- For micro/small wind systems, maintenance cost estimations are based on a bi-annual check and service taking half a day. The actual maintenance may vary depending on the turbine quality and location.
- Capital costs for the small to large scale turbines are based on an installed cost of £46,000 for a 15kW turbine, £150,000 for a 50kW turbine, £250,000 for a 100kW turbine and £1,470,000 for a 1MW turbine (2009) based on discussions with several UK suppliers and BWEA. Costs include civil works for an average site.

For reference, an Ernst & Young report for the DTI in 2007 quoted a capex of £1,089/kW, and an opex of £41/kW for large scale turbines.[14]

Technology cost projections

The fixed and marginal costs reduce over time to allow for improvements to mounting and installation, and the development of wind turbine specific power electronics.

Costs are expected to decline as the installed base grows and supply chains mature and as wind turbine specific power electronics are developed further.[15] Supply chains are particularly limited for new turbines in the 50–500kW bracket.

Future costs are given in 2008 prices.

2015			
System size/type	**Fixed cost (per site)**	**Marginal cost (£/kW)**	**Annual Maintenance**
Building mounted (<1.5kW)	£2,116	£1,209	£110
1.5–15kW	£10,000	£1,209	£220
15–50kW	£2,444		£61 per kW
50–250kW	£2,444		£61 per kW

[13] Capital costs are based on the following manufacturers: Ampair, Eclectic Energy, Marlec, Renewable Devices and Zephyr.

[14] http://www.berr.gov.uk/files/file39038.pdf

[15] Potential costs reductions are more limited for small systems due to high costs of civil works and the planning process, which are not expected to change significantly over time.

250–500kW	£2,037	£60 per kW
500–3,000kW	£1,278	£38 per kW

2020			
System size/type	**Fixed cost (per site)**	**Marginal cost (£/kW)**	**Annual maintenance cost**
Building mounted (<1.5kW)	£1,932	£1,137	£110
1.5–15kW	£10,000	£1,137	£220
15–50kW	£2,200		£55 per kW
50–250kW	£2,200		£55 per kW
250–500kW	£1,833		£46 per kW
500–3,000kW	£1,139		£34 per kW

7.3 Hydro power

Key parameters

For electricity generation from a hydro source to be feasible, it is necessary to harness the energy from the movement of a significant amount of water. Typically a suitable stream, river, or weir is therefore required. At small scales (<10kW) a low head (<10m) system is assumed, whereas at the 10–50kW scale a medium head (10–50m) system is costed.

System size	Turbine efficiency	Load factor	System efficiency (water to wire)
1–10 kW	85%	30%	70%
10–50kW	85%	30%	70%
50–100kW	85%	30%	70%
100–500kW	85%	30%	70%
500kW–5MW	85%	30%	70%

Current technology costs

2009			
System size	**Fixed cost (per site)**	**Marginal cost (£/kW)**	**Annual maintenance cost**
1–10 kW	£8,000	£4,200	£440
10–50kW	£10,000	£3,000	£440
50–100kW	£3,200 per kW		£12,500
100–500kW	£3,000 per kW		£20,000
500-1,000kW	£2,750 per kW		£50,000
1,000kW–5MW	£2,250 per kW		£50,000

- For small systems, capital costs are highly site-specific, and vary from £3,000 to £10,000 per kW.[16]
- A low head system could cost from c. £4,000 per kilowatt up to 10kW.[17]
- Costs for a medium head system are around £10,000 fixed with an additional £2,500 per kilowatt up to 10kW.[18]
- Although some reduction in turbine costs is expected due to increases in production volumes, civil works and the planning process dominate the total installation cost and these are not expected to change significantly in the future.
- On small systems (<50kW), maintenance costs are based on an annual inspection/service taking one day. Routine maintenance such as screen cleaning is normally carried out by the owner. On larger systems, we have assumed an annual maintenance charge based on a service contract.

[16] Based on discussions with mill owners in the South West of England.
[17] http://www.cus.net/renewableenergy/subcats/hydroelectric/hydroelectric.html
[18] http://www.cus.net/renewableenergy/subcats/hydroelectric/hydroelectric.html

- Capital costs for hydro projects comprise three main components: about 10% is for design studies and administrative costs, 55–60% for civil engineering and 30–35% for hydromechanical and electrical equipment.

Technology cost projections

2015 & 2020			
System size	**Fixed cost (per site)**	**Marginal cost (£/kW)**	**Annual maintenance cost**
1–10 kW	£8,000	£4,200	£440
10–50kW	£10,000	£3,000	£440
50–100kW	£3,200 per kW		£12,500
100–500kW	£3,000 per kW		£20,000
500-1,000kW	£2,750 per kW		£50,000
1,000kW–5MW	£2,250 per kW		£50,000

7.4 Wave power

Key parameters

Waves incident on the UK's Atlantic coastline have a power density of around 40kW per metre of shoreline.[19] The UK benefits from an exposed Atlantic coastline of the order of 1,000km, which implies a technical resource of over 40GW. Although the number of commercially available wave energy converters is currently small, much research and development is on-going in this area. The approach employed to estimate the sub-5MW wave resource is described in Appendix B. The resource was divided into 4 bands of different average wave powers, from 7.5kW/m to 30kW/m.

Technology parameters

Resource band	Capex in 2009 (£/kW)	Capex in 2015 (£/kW)	Capex in 2020 (£/kW)	Fixed Opex (£/kW)	Load factor (%)
Wells turbine (7.5kW/m)	£7,824	£7,000	£6,500	£63	13%
Wells turbine (15kW/m)	£7,824	£7,000	£6,500	£63	26%
Wells turbine (22.5kW/m)	£7,824	£7,000	£6,500	£63	39%
Wells turbine (30kW/m)	£7,824	£7,000	£6,500	£63	52%

Commercial wave power is a nascent market. The world's first commercial wave farm was officially opened in September 2008 and many wave energy generators are currently at the demonstration and development phase. The costs above are based on industry data from a small number of stakeholders.

Technology cost projections

Due to the relative immaturity of this market, significant cost reductions are anticipated. For example, experience gained through demonstration projects will allow efficiency

[19]http://www.ma.hw.ac.uk/~denis/wave.html
ftp://ftp.ma.hw.ac.uk/pub/denis/waveuk.pdf

improvements through design modifications. Also, further research and development could lead to lower manufacturing and assembly costs for example.

7.5 Tidal power

Key parameters

The UK benefits from one of the largest tidal resources in the world. The total incoming tidal power incident on the UK from the Atlantic Ocean has been estimated at 250GW.[20] Like wave power machines, tidal generators are at an early stage of commercialisation, with several technology demonstration projects currently on-going. There are a number of alternative methods of capturing energy from tides, including tidal stream generators (operating on the same principles as wind turbines, only under water), tidal barrages, tidal lagoons, tidal fences, and tidal reefs. Tidal barrages are a proven technology, for example the barrage at La Rance in France has produced 60MW of power on average since 1966. However, such technology is not relevant for this study as any barrage is likely to far exceed the 5MW$_e$ feed-in tariff cap. Tidal lagoons, which are created by building walls in the sea (effectively creating an artificial estuary), also benefit from advantages of scale and so are also unlikely to be relevant to this study. The most likely pertinent technology for this work is the tidal stream generator. A number of these devices are currently under development in the UK, and current designs are for turbines with a power output of around 1MW.

Current technology costs

2009					
Technical Capex (£/kW)	**Civils Capex (£/kW)**	**Connection Capex (£/kW)**	**Total Capex (£/kW)**	**Fixed Opex (£/kW)**	**Variable Opex (£/kWh)**
2,170	790	790	3,750	100	0

Several tidal stream demonstration projects are currently underway and the commercialisation of this technology remains at an early stage. Certainty over current and future costs will increase as the first commercial-scale projects are deployed.

[20] Cartwright, D. E., Edden, A. C., Spencer, R., and Vassie, J. M. (1980). *The tides of the northeast Atlantic Ocean*. Philos. Trans. R. Soc. Lond. Ser. A, 298(1436):87–139.

7.6 Biomass CHP

Key parameters

A range of different technologies involving biomass feedstocks currently exists, and each technology has an associated capacity range in terms of power output. Sizes selected represent assumptions on current suitable ranges for the technologies listed. Some technologies perform better in CHP applications than others, and if electricity generation is the sole purpose, efficiencies can be improved by designing and running the technology for production of electricity only. In the table below, the overall efficiency is defined as the net useful energy output (including heat for a CHP plant) as a percentage of the energy content of the fuel (LHV).

Plant size (kWe)	Technology	Heat to power ratio	Electrical efficiency	Overall Efficiency
100kWe–500kWe CHP	Heat turbine	3.8:1	17%	82%
500kWe–3MW CHP	Organic Rankine Cycle	4.3:1	16%	85%
3–5MWe CHP	Steam turbine CHP	2.7:1	23%	85%
3–5MWe	Steam turbine (electricity only)	N/A	27%	27%

Current technology costs

2009		
Plant size (kWe)	**Marginal cost (£/kWe)**	**Annual maintenance cost**
100kWe–500kWe CHP	£4,700 per kWe	5.0% of capex
500kWe–3MW CHP	£5,800 per kWe	2.5 % of capex
3–5MWe CHP	£2,500 per kWe	3.9% of capex
3–5MWe Electricity only	£2,500 per kWe	3.9% of capex

- Fixed costs do not include heat distribution costs.
- Costs for the 100kWe–500kWe are based on a Talbotts 100kWe system.
- Costs for the 3–5MW biomass steam turbine are based on a recent quote for a 3.5MW system of c. £7 million. Maintenance costs are based on £13 per MWh and run hours of 6,000 hours per annum.
- Costs for the ORC system are based on €6.43 million for a 1MW system. Other quotes include €4.5 million for a 500kW system and €8.15 million for a 1.5MW system.

- Costs have been cross checked against Pöyry internal numbers and Ernst and Young (2007) projections.

Technology cost projections

2015		
Plant size (kWe)	**Marginal cost (£/kWe)**	**Annual maintenance cost**
100kWe–500kWe CHP	£3,360 per kW	5.0% of capex
500kWe–3MW CHP	£4,872 per kW	2.5 % of capex
3–5MWe CHP	£2,625 per kW	3.9% of capex
3–5MWe Electricity only	£2,625 per kW	3.9% of capex

2020		
Plant size (kWe)	**Marginal cost (£/kWe)**	**Annual maintenance cost**
100kWe–500kWe CHP	£2,960	5.0% of capex
500kWe–3MW CHP	£4,292	2.5 % of capex
3–5MWe CHP	£2,450	3.9% of capex
3–5MWe Electricity only	£2,450	3.9% of capex

7.7 Gas CHP

Key parameters

Parameter	Domestic		Commercial
Technology type	Stirling Engine	Fuel Cell	Gas Engine
Indicative size	1kWe	1kWe	5–50kW
Heat:power ratio	6:1	1:1	2:1
Electrical efficiency (%)	12%	43%	35%
System efficiency (%)	85%	85%	85%

Current technology costs

2009			
System size/type	**Fixed cost (per site)**	**Marginal cost (£/kWe)**	**Annual maintenance cost**
Domestic (Stirling engine)	£2,000	£1,500	£110
Domestic (fuel cell)	£2,000	£6,000	£110
Commercial (gas engine)	£1,500 total per kWe		£100 per kWe

- Fuel cell micro CHP capital costs are based on discussions with a UK manufacturer. These are projections as units are not currently available.
- Stirling engine micro CHP costs are based on current prices for a 1kWe system.
- Maintenance costs for domestic systems assume 0.25 days per year professional service/maintenance in line with current boiler requirements. Maintenance requirements are currently much higher due to technology immaturity and for the systems to succeed in the market a reduction to boiler levels will be necessary.
- Larger CHP capital costs can vary depending on installation requirements. The costs used here are based on an in installed cost of £25,000 for a 13kWe system and £75,000 for a 50kWe system.
- Reciprocating CHP technology has a relatively large installed capacity and the technology is mature. For this reason, the projections assume negligible cost reduction.

- Maintenance costs assume an annual service contract costing £1,350 for a 13kWe gas engine and £7,000 for a 50kWe system. These costs include an annual service, parts, labour and an engine rebuild/replacement every five years.
- CHP operation hours need to be high for feasible systems. The use of 5,000 hours per year reflects a system which is used throughout the year for space hearing and hot water and makes use of thermal storage.

Technology cost projections

Neither Stirling engines nor fuel cells are currently available in commercial quantities. Stirling engines are expected to become available through energy suppliers in 2009, and fuel cells should follow in one or two years. As such, cost reductions are expected to occur as production volumes increase and supply chains mature. Gas engine CHP is already widely used globally and is based on mature technology; costs are therefore assumed to remain static in the future.

2015			
System size/type	**Fixed cost (per site)**	**Marginal cost (£/kWe)**	**Annual maintenance cost**
Domestic (Stirling engine)	£2,000	£1,296	£110
Domestic (fuel cell)	£2,000	£2,753	£110
Commercial (gas engine)	£1,500 total per kWe		£100 per kWe

2020			
System size/type	**Fixed cost (per site)**	**Marginal cost (£/kWe)**	**Annual maintenance cost**
Domestic (Stirling engine)	£2,000	£1,156	£110
Domestic (fuel cell)	£2,000	£1,881	£110
Commercial (gas engine)	£1,500 total per kWe		£100 per kWe

8 Appendix B – Estimation of the potential for sub-5MW renewable electricity.

8.1.1 Photovoltaics

Commercial systems

The potential resource for building-integrated and building-attached PV in Great-Britain is constrained by available roof area. The suitable roof-space on buildings in the non-domestic sector was estimated using floor space data from the Valuation Agency Office. The floor space data were converted to suitable roof areas using factors determined by the IEA study, *Potential for Building Integrated Photovoltaics* (2002).[21] These factors attempt to take into account the percentage of architecturally unsuitable roof space and roof area with insufficient solar yield due to orientation. A space utilisation factor is also applied to allow for access on the roof around the PV array and for installation of safety systems. Calculations assume typically 70% of the available roof area may be covered with PV panels. Table 33 shows the factors used to convert floor areas to suitable roof areas for non-domestic buildings.

Table 33 Factors used to convert building floor area to suitable PV roof area (from IEA 2002)

Conversion factor	Value
Ratio of roof area to floor area	1.2
Suitable architectural building envelope	0.6
Roof area with sufficient insolation	0.55
Space utilisation factor	0.7
Overall conversion factor	**0.28**

Total commercial and industrial floor space was estimated at ward level and each ward was allocated to one of four insolation bands, as shown in Figure 27. The overall potential was then broken down into a number of discrete system sizes using data on the size distribution of commercial premises from the VOA, shown in Table 34. The maximum system size permitted on premises with floor areas of less than $30m^2$ is 1kW, which is substantially smaller than the majority of commercial installations. For this reason, these premises were excluded from the analysis. Table 34 also shows that 93% of premises have floor spaces less than $1000m^2$, equivalent to a maximum PV system size of $35kW_e$.

[21] http://www.iea-pvps.org/products/rep7_04.htm

In addition to commercial roof-based systems, there is also significant potential for stand-alone systems on agricultural land. The total resource is dependent on the amount of available land and the economic attractiveness of PV compared with alternative land uses. There are additional constraints due to the ability of the electricity grid to absorb large amounts of renewable energy in rural areas where land availability is highest. We have assumed that the absolute potential for stand-alone installations is 0.05% of agricultural land. The total agricultural land area in the UK is 15 million hectares[22], so the stand-alone PV resource is approximately 9GW, or 8TWh of electricity per year.

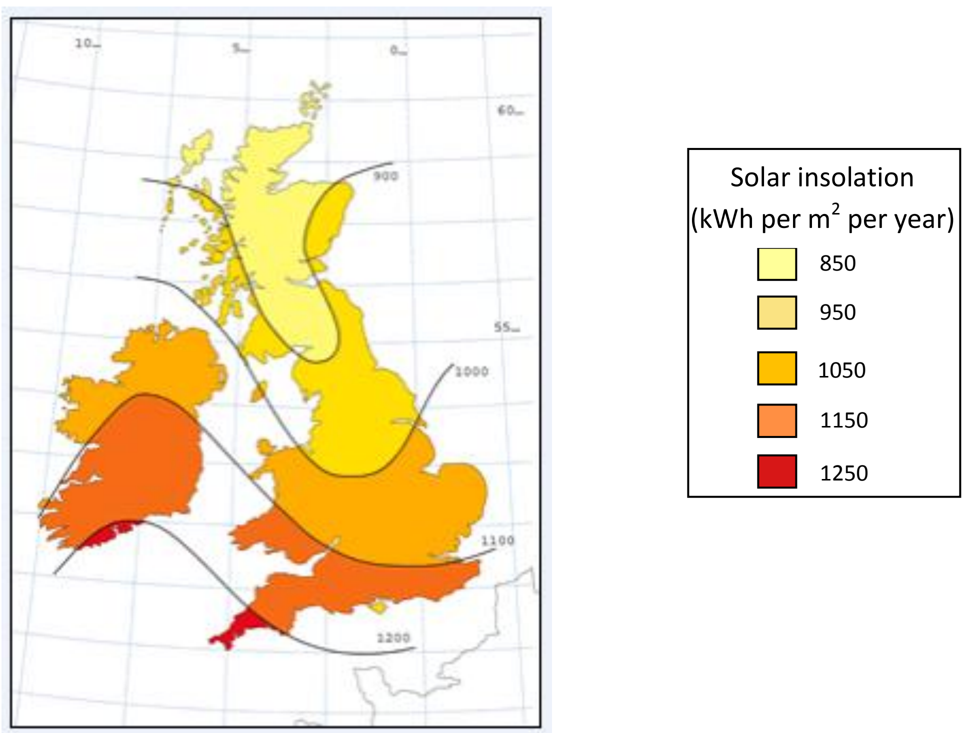


Figure 27 Insolation map of the UK

Table 34 PV system sizes for different floor space bands

Premises floor area (m2)	% of premises	PV area (m2)	Max PV array size (kW)
Less than 30	10%	8	1
31-100	37%	28	3.5
101-300	31%	84	11

[22] Data from UK Land Directory : http://www.uklanddirectory.org.uk/land-use-statistics.asp

301-1000	16%	280	35
1001-3000	5%	840	105
3001-10000	1%	2,800	350

Domestic Resource

In the domestic sector, it will be assumed that 50% of households (excluding flats, maisonettes and apartments) have potential to install PV. This is to account for some lack of ideal orientation and lack of architectural suitability of certain properties (e.g. listed buildings). All domestic properties are assumed to install 2.5kW$_e$ systems, requiring a roof area of 20m^2. The annual new build rate is assumed to be 1% of the existing stock, and systems can be installed at significantly lower cost on these buildings. After one year, new build properties without PV are added to the existing building potential since the benefit of lower installation costs only applies during construction.

The total PV resource in Great Britain is shown in Table 35. The total resource is 60 TWh per year, with over one-third of this potential found in the domestic retrofit sector. Of the commercial-resource, 5.5TWh are in small, 4-10kW systems, while 8.5TWh is from stand-alone systems on agricultural land.

Table 35 Total PV resource in the domestic and commercial sectors

Type	Technical resource (TWh per year in 2010)
New build domestic (2.5kW)	0.18
Retrofit domestic (2.5kW)	22.1
New build 4-10kW	0.04
Retrofit 4-10kW	5.5
New build 10–100kW	0.11
Retrofit 10–100kW	11.0
New build 100–5000kW	0.13
Retrofit 100–5000kW	12.8
Stand alone system	8.5
Total	**60.4**

8.1.2 Wind

Estimation of resource potential

Micro-wind

Micro-wind turbines tend to be linked to buildings, either because they are physically attached or linked to the building's electrical system in the case of mast-mounted micro turbines. Therefore, the potential resource for these machines depends on the number of suitable buildings. The potential for micro-wind is a trade-off between the number of buildings and expected load factors. While the turbines themselves can be installed on a large number of buildings, recent field trial results suggest that the majority of urban sites may have very low load factors due to low mean wind speeds and turbulence caused by surrounding buildings. Therefore, it was assumed that micro-wind is not suitable for urban areas. This is consistent with analysis by the Carbon Trust, which concluded that there was almost no urban wind resource available at a generating cost of less than £100/MWh, and the urban sites comprised only 10% of the total resource available at £1000/MWh[23]. In wards that meet the criteria for wind speed and rurality, it is assumed that one micro-wind turbine can be installed on each house. For homes in the most rural wards, it is assumed that consumers install mast-mounted turbines in gardens rather than building-mounted machines. Turbines are not permitted on flats. Table 36 shows the potential for micro-wind turbines in Great Britain. The total potential is approximately 3.5 million machines, with two thirds of this resource occurring below 6m/s.

Table 36 Potential for micro-wind turbines in Great Britain

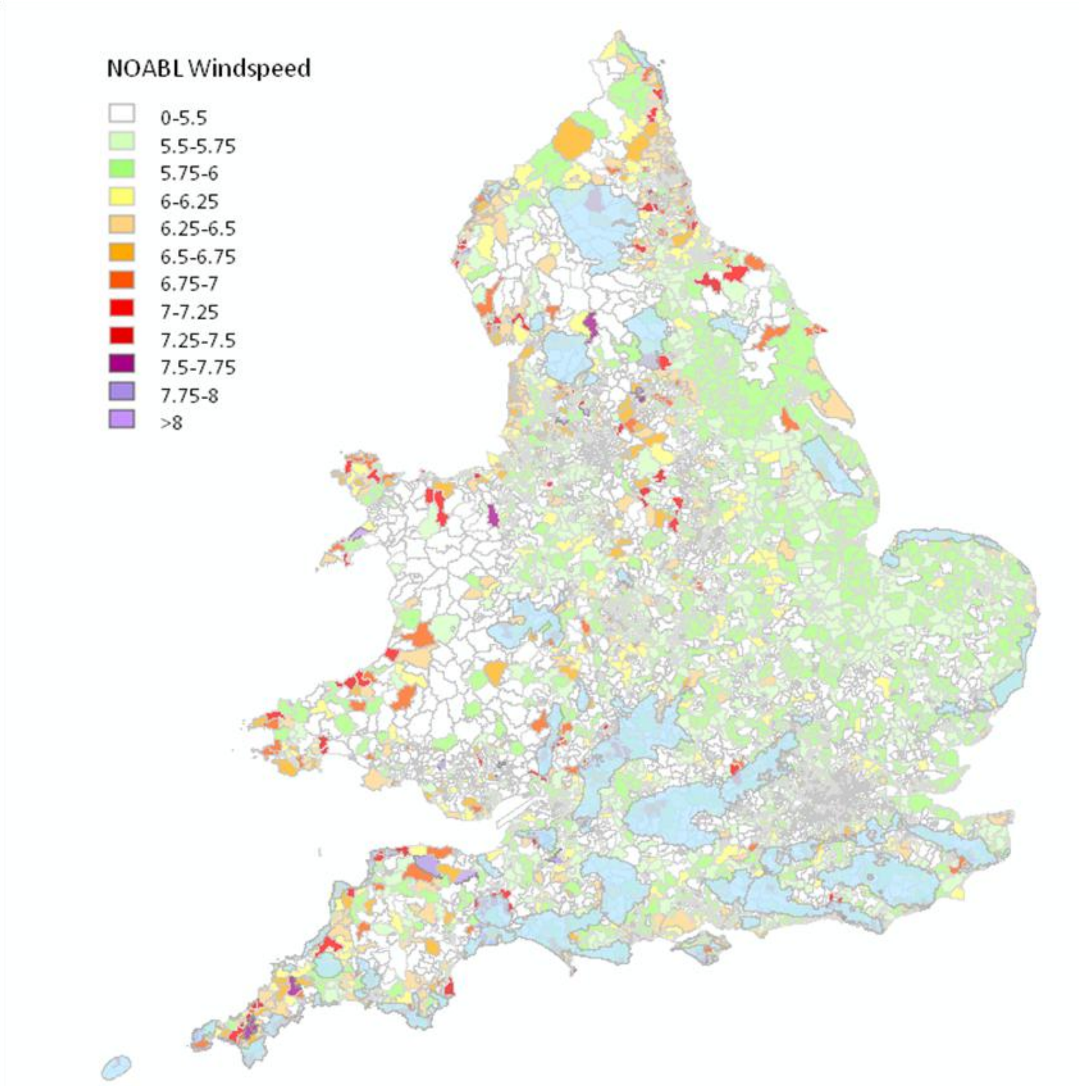
Windspeed (m/s)	*No. of building-mounted micro turbines*	*No. of mast-mounted micro turbines*
5.5–6.0	2,102,576	155,328
6.0–6.5	579,815	116,249
6.5–7.0	208,657	66,251
7.0–7.5	87,442	28,493
7.5–8.0	31,994	20,606
>8.0	13,212	14,646
TOTAL	**3,052,251**	**394,398**

The potential for sub-5MW wind in Great Britain is assumed to be constrained by wind-speed and the availability of local grid capacity. Assessment of wind potential was based on the NOABL wind speed database, combined with energy consumption and greenspace data for each ward in England. Since data at ward level were not available between Scotland and Wales, representative English regions were used as a proxy. Analysis conducted by Element Energy (2008)[24] suggested that sub-5MW turbines are unlikely to be economic at wind-

[23] Carbon Trust (2008): Small-scale Wind Energy: Policy insights and practical guidance
[24] Element Energy (2008) - The growth potential for on-site Renewable electricity generation in the non-domestic sector in England, Scotland and Wales

speeds of less than $5.5ms^{-1}$, even with high levels of support from a Feed in Tariff, and wards with wind speeds below this value were excluded from the analysis. Figure 28 shows the annual mean wind speeds for each ward in England and Wales.

Figure 28 Annual mean wind speeds in English and Welsh Wards (m/s). Areas of Outstanding Natural Beauty are shaded in blue.



For a given ward, the total wind potential was then constrained by the strength of the local electricity grid. A national map of grid capacity limitations on the 11kV distribution grid is not publically available, so the total electricity demand in the ward was used as a proxy. The corresponding base load power demand was multiplied by 2.5 to give the peak power that can be accepted by the local grid.

Once the grid constraints had been established for each ward, the amount of green space was used to determine the maximum turbine size that could be installed. Due to the lack of green space in dense urban areas, wards with this classification were excluded at this stage.

Table 37 Maximum turbine size for different greenspace bands

Greenspace fraction within ward	Indicative turbine size (kW)
<30%	6
30-50%	30
50-70%	150
70-80%	375
>80%	1500

Table 38 shows the total potential for sub-5MW wind in Great Britain. The total resource is over 17TWh, with large megawatt-class turbines contributing over half of this total. This is equivalent to over 4% of UK electricity demand.

Table 38 Total sub-5MW wind resource in Great Britain

Turbine size	Total resource (TWh per year)
Micro	3.79
1.5-15kW	1.06
15-50kW	1.35
50-250kW	1.45
250-500kW	1.64
500-3000kW	8.39
Total	**17.69**

8.1.3 Hydro power

Several studies have attempted to quantify the hydropower resource in the UK. The most detailed was carried out by the Energy Technology Support Unit (ETSU) in 1989 for the Department of Energy. The study estimated the UK hydropower resource to be 320MW. However, the analysis was based on the number of schemes that were financially viable at the economic conditions and policy support at the time. This meant that low head sites, and any sites with potential power outputs below 25kW, or 50kW in rural areas, were excluded from the analysis. Turbine technology has advanced since 1989, and a Feed-in Tariff is likely to significantly improve economics of hydropower installations and will allow a larger potential to be harnessed. The Scottish Hydropower Resource report estimated a potential of 620 MW from sub-5MW installations. A recent report by IT Power suggested that the small and medium-scale hydro resource in England and Wales is approximately 250MW. Including the Northern Ireland resource, the total hydro resource in the UK is approximately 1GW.

The reports cited above do not contain a breakdown of the resource by turbine size. Work by the Joule Centre estimated that there are 10,000 sites with power outputs below 5kW and a further 1,000 sites with outputs between 5kW and 100kW[25]. We have assumed the following resource potential for each turbine size:

Table 39 UK hydro power resource by system size

System size range	Potential no. of UK installations	Potential capacity (MW)	*Total resource (MWh/yr)*
1–10kW	10,000	50	0.22
10–50kW	500	15	0.07
50–100kW	500	37.5	0.16
100–500kW	1,000	300	1.31
500–1,000kW	500	375	1.64
1,000–5,000kW	100	300	1.31
Total	**12,600**	**1,078**	**4.72**

25 Joule Centre research cited in http://www.imsplc.com/articles/HYDRO%20POWER%20ARTICLE.pdf

8.1.4 Wave power

Estimation of resource potential

In terms of potential for the UK, the maximum available energy from wave power depends on the number of wave energy converters deployed and their efficiencies in converting the raw resource of c.40GW (see above) into electricity. According to the manufacturer, the Pelamis wave energy converter (currently deployed in the Atlantic off the coast of Northern Portugal) produces around 5.3kW_p per metre of machine and has a load factor in the region of 25–40%. Taking a relatively conservative figure of 30% load factor, with 5.3kW_p per metre, this implies that the absolute maximum energy available would be of the order 14TWh per year if all 1,000km of available coastline were exploited. Given the high cost of connecting marine renewable energy systems to the land-based electricity grid, it is likely that the majority of these devices will be installed in clusters with a total capacity greater than the 5MW limit for the Feed-in Tariff. For example, the three Pelamis devices currently operating of the Portuguese coast have a peak output of 2.25MW, but a further 28 machines will be added to take the overall peak capacity to 22.5MW[26]. For this reason, it was assumed that all sub-5MW installations will be based on existing breakwaters near to shore. The potential for these near-shore systems was based on an analysis of the Atlas of UK Marine Energy Resources. Only sites with water depths less than 25m and a distance of 5km from the shore were included. The resource was further constrained by allowing only sites that were close to a centre of population, used as a proxy for electricity grid capacity. For each of suitable sites, the atlas provided the mean annual wave power (in kW/m), which was used to estimate the annual energy yield from each project.

Table 40 shows the estimated potential for sub-5MW wave power in the UK. The analysis shows that there are only 26 sites suitable for small wave projects. The total resource assumes a water to wire efficiency of 50% and a system availability of 85%. The total capacity assumes a peak power rating of 4MW_e per site.

Table 40 Potential for sub-5MW wave power in the UK

Mean annual wave power (kW/m)	No. of suitable sites in UK	Total resource (GWh per year)	Total capacity (MW)
7.5	11	77	44
15	5	70	20
25	10	233	40
Total	**26**	**379**	**104**

[26] Based on discussions with the manufacturer. See http://www.pelamiswave.com/content.php?id=149

8.1.5 Tidal power

Estimation of resource potential

The world's first commercial tidal stream generator is located in Strangford Lough in Northern Ireland and has an output of up to 1.2MW. Other commercial projects are planned for the UK, for example off the coast of Anglesey and Pembrokeshire in Wales. Like wave power, it is expected that the costs involved in offshore construction, maintenance and grid connection will strongly favour clusters of turbines with total power outputs well above $5MW_e$. We have assumed that sub-5MW projects are sized at 5MW and sited close to the shore. Black and Veatch (2008)[27] conducted a detailed review of the UK's tidal stream resource. The total UK resource was estimated to be 118TWh, with 18TWh of this technically extractable. However, 70% of the resource is in water depths greater than 30m, and there are only 18 identified sites in depths below 25m. These 18 sites are assumed to form the sub-5MW in this study. Table 41 shows the estimated sub-5MW tidal resource in the UK. The total resource is 0.2TWh, equivalent to 0.05% of UK electricity consumption.

Table 41 Estimated sub-5MW tidal resource in the UK

Mean spring tide peak velocity (m/s)	Installed capacity at each site	No. of UK sites with depth less than 25m	Load factor	Total resource (GWh/yr)
<2.5	5MWe	4	20%	35
2.5–3.5	5MWe	11	25%	120
>3.5	5MWe	3	30%	39
			Total	**194**

[27] Black and Veatch (2005) –Tidal Stream Resource and Technology Summary Report http://www.carbontrust.co.uk/NR/rdonlyres/19E09EBC-5A44-4032-80BB-C6AFDAD4DC73/0/TidalStreamResourceandTechnologySummaryReport.pdf

8.1.6 Biomass

8.1.6.1 Potential for biomass CHP in district heating networks

In the majority of Feed-in Tariff scenarios described in the Analysis section, it is assumed that all sub-MW biomass plants will be operated in CHP mode. This is because electricity only plants at the sub-5MW scale have low electrical efficiencies compared to conventional thermal plant (25% compared with 40%+), and so if biomass is to be used in electricity-only plants, it should be co-fired in gigawatt scale sites rather than burned in small, decentralised systems.

For CHP plants, the overall resource for electricity generation is constrained by the availability of heat loads. The heat loads are divided into those supplied through a district heating network, or on-site loads in commercial or industrial premises.

Several recent studies have quantified the potential for district heating in the UK. Like estimates of the hydro power resource, they are based on the number of schemes that are financially viable at current technology and fuel prices. A recent study for Defra[28] conducted an analysis based on heat densities (expressed in MW per km^2) for domestic and commercial premises in different post-codes throughout the UK. The rates of return for CHP plants constructed to supply these loads were then calculated, and the total resource at three rates of return was estimated. The total resource was found to be extremely sensitive to the rate of return chosen, with a resource of 150TWh heat per year at 6% decreasing to 0.6TWh at a commercial rate of 9%.

A more recent study by Faber Maunsell also found the potential for district heating to vary widely depending on assumptions on discount rates and policy support. The median potential in the Faber Maunsell study is 18.3TWh of heat per year, which assumes a 6% discount rate and a reduction in the capital costs of the CHP plants of 20%. Since this closely reflects the technology cost projections in this model, we have based the potential for district heating on this scenario. Given the large heat loads in some dense urban areas, these areas may be served by plants larger than $5MW_e$. It is assumed that if a sufficiently generous Feed-in Tariff is offered to sub-5MW plants, these smaller plants will be deployed in preference to larger plants since they offer better rates of return.

For CHP plants supplying heat through a district heating system, the cost of consumer connections significantly increases the levelised cost of energy. Whether the heat network is financed by the plant operators or a third party, the costs are borne by the heat supplier

[28] Defra (2007) http://www.defra.gov.uk/environment/climatechange/uk/energy/chp/pdf/potential-report.pdf

since it reduces the price it can charge for heat supplied to end users. Connection costs vary substantially with the housing density area in a given area. The Town and Country Planning Association estimates connection costs per dwelling to vary from £2,500 for a high rise apartment to £9,550 for a detached house[29]. Table 42 shows the connection costs for the three dwelling types used in the model. The connection costs differ from those in the TCPA study because the dwelling categories differ slightly from those in this model. Heat demands per dwelling are based on an analysis carried out by Element Energy for the Energy Saving Trust on the potential for community-scale renewable energy[30]. When adjusted for the heat demands of individual dwellings, the connection cost per kWh varies from 1.1p/kWh for urban flats to 2p/kWh for detached houses. This in addition to the price paid by end users for the heat supplied through the network.

Table 42 District heating network connection costs

Technology	Dwelling type	Connection cost	Heat demand per dwelling (kWh)	Number of dwellings served	Connection charge per kWh heat delivered (p/kWh)
100kW heat turbine	Urban flats	£3,133	14,391	104	1.1
	Terraced houses	£5,300	15,510	97	1.7
	Detached/semi-detached houses	£8,625	21,622	69	2.0
Organic Rankine Cycle	Urban flats	£3,133	14,391	1,390	1.1
	Terraced houses	£5,300	15,510	1,290	1.7
	Detached/semi-detached houses	£8,625	21,622	925	2.0
Steam turbine	Urban flats	£3,133	14,391	3,127	1.1
	Terraced houses	£5,300	15,510	2,901	1.7
	Detached/semi-detached houses	£8,625	21,622	2,081	2.0

The connection cost per dwelling is significantly lower in new dwellings than in retrofit installations. This is because developers avoid the need to install conventional boilers in the homes. In addition, the cost saved in not connecting the property to the gas grid offsets some of the cost of the heat pipes. We have assumed that the total value of the savings in new build properties is £2,000 per dwelling. However, the lower connection costs are partly

[29] TCPA (2008) : Community Energy - Urban Planning for a Low Carbon Future
[30] EST (2008): Power in Numbers – The Benefits and Potential of Distributed Energy Generation at the Small Community Scale.

offset by the lower heat demands of new buildings due to improved energy efficiency. When expressed per kWh of delivered heat, the connection cost for detached and semi-detached dwellings is 50% higher in new build versus retrofit properties. Costs for urban flats are lower because the boiler cost saving comprises a higher proportion of the total connection cost.

Table 43 Connection costs for new dwellings

Technology	Dwelling type	Connection cost	Heat demand per dwelling	Number of dwellings served	Connection charge per kWh heat delivered (p/kWh)
100kW heat turbine	High-rise apartment	£1,133	10,000	150	0.6
	Terraced houses	£3,300	10,000	150	1.7
	Detached/semi-detached houses	£6,625	10,000	150	3.3
Organic Rankine Cycle	High-rise apartment	£1,133	10,000	2,000	0.6
	Terraced houses	£3,300	10,000	2,000	1.7
	Detached/semi-detached houses	£6,625	10,000	2,000	3.3
Steam turbine	High-rise apartment	£1,133	10,000	4,500	0.6
	Terraced houses	£3,300	10,000	4,500	1.7
	Detached/semi-detached houses	£6,625	10,000	4,500	3.3

8.1.6.2 CHP Potential in Individual Buildings

The potential for biomass CHP in individual commercial premises is based on Defra (2007)[28]. This analysis was based on the BRE's non-domestic energy model, which was used to estimated total heat loads and load profiles of a range of commercial building types and sizes. These load profiles were then interacted with the heat and power characteristics of the most suitable CHP technology, to estimate the rate of return for each building type. The study identifies a total heat load in buildings suitable for CHP of 12TWh per year, which is relatively insensitive to the discount rate chosen. It should be noted that the analysis in Defra (2007) was based on gas-fired CHP. We have assumed that due to additional constraints on air quality in dense urban areas and space limitations, only 50% of the 12TWh potential is available to biomass technologies.

Assessing the potential for CHP in industrial premises is more challenging, given subset of CHP technologies investigated in the model. Many industrial heat loads are at higher temperature than can be supplied by heat turbines or organic rankine cycle systems, and loads in many premises are substantially higher than can be supplied by sub-5MW_e plants. Work being carried out on the Renewable Heat Incentive by NERA and AEAT identifies an industrial biomass heating potential of 18.75TWh_{th} in 2,000 sites. Since biomass CHP systems are subject to similar air quality and space constraints as heat only biomass, we have assumed that all of this potential is available for biomass CHP given sufficient Feed-in Tariff support.

Table 44 Total biomass CHP resource in all sectors

Type	Annual Resource (TWh)
District heating - new build	1.5
District heating - retrofit	17
Stand-alone commercial	6
Low temperature industrial	18.75
Total	**43.25**

8.1.7 Waste

The resource for electricity generation from waste is constrained by the amount of suitable waste. Incineration and advanced thermal treatment plants are more versatile can treat any carbon rich waste, including plastics, and hence is more versatile than AD which can only treat biological waste. In addition, other non-electricity technologies such as mechanical biological treatment (MBT), recycling, and composting compete for waste that is not sent to landfill.

Table 41 shows the estimated sub-5MW waste resource in the UK. It is assumed that the only 5% of suitable carbon-rich feedstocks are available to sub-5MW incineration and ATT plants, with the remainder being used in larger plants or recycled. Of the 5% of the overall waste resource available to sub-5MW thermal plants, 50% each is allocated to ATT and incineration systems. The entire food-waste resource is available to AD plants if the financial returns are sufficiently good. In other words, if a generous feed-in tariff were offered to AD plants, food-waste would be diverted from other treatment technologies. The total sub-5MW resource is assumed to be over 4.5TWh, or 1% of UK electricity consumption. Over 3TWh of this resource is in AD plants.

Table 45 Estimated sub-5MW waste resource

Technology	Energy density of waste (kWh/t)	Annual resource available (tonnes)[31]	Overall electrical efficiency	Annual electricity generation (TWh)
Advanced Thermal Treatment	4,469	637,682	26%	0.74
Anaerobic Digestion	2,222	12,447,259	12%	3.32
Incineration	4,469	637,682	18%	0.51
			Total	**4.57**

[31] From Defra waste statistics

8.1.8 Gas CHP

The potential for small and medium scale CHP is constrained by the availability of sites with sufficient heat demand to ensure sufficient run hours for the system. In the domestic market, there are approximately 20 million homes with a gas connection, so the technical capacity for domestic CHP is over 20GWe. Since these devices compete in similar sites, it is not possible to allocate the resource to the individual technologies. The uptake of Stirling engine and fuel cell will be determined by their economic performance relative to the incumbent (gas boilers), each other, and other low carbon technologies such as heat pumps or biomass boilers. However, due to the low heat demands of modern homes, Stirling engines are fundamentally ill-suited to new build properties. The lower heat to power ratio of fuel cell micro CHP units makes this technology better suited to the domestic market, potentially including new build properties. However, this technology is still at the demonstration phase and domestic fuel cell CHP units are not currently commercially available.

The UK CHP resource was divided into high and low run hours installations in both commercial and domestic buildings. Since CHP systems with peak power outputs above 50kW_e are not eligible for support under the Feed-in Tariff, buildings whose heat demands could not be met by systems of this size were excluded from the analysis. It was assumed that commercial buildings could install a gas-engine CHP system rated at 10kW_e or 50kW_e. Domestic buildings could install Stirling engines or fuel cell, both rated at 1kW_e. When operated in heat-led mode with no heat rejection, system run hours and hence electricity generation is highly site-specific. Table 46 shows the full load run hours for the range of CHP systems and site types. Due to the high heat to power ratio of Stirling engine systems, electricity production in new build properties is much lower than from an equivalent fuel cell. Gas-engine systems in high run hours premises, such as hotels and small leisure centres with pools, are assumed to run for 6,000 hours per year, with systems in less optimal sites running for 3,000 hours.

The number of potential installations in domestic buildings is based on housing data from DCLG and the English Housing Condition Survey data. High run hours buildings were defined as homes constructed before 1980, due to lower thermal efficiencies, and low-run hours buildings were those built after 1980. The potential in commercial buildings is based on data on commercial floorspace from the Valuation Office Agency. These data relate to ‘bulk class’ premises, defined as offices, retail, warehouses and factories, and are assumed to have low occupancy hours and hence low CHP run hours. Previous Element Energy analysis identified an additional 60,000 ‘non-bulk’ premises, such as hospitals, residential homes, and leisure centres with high potential CHP run hours. The CHP potential in new buildings is based on 240,000 new homes constructed each year, with 80% suitable for gas-fired CHP, and a 1% increase in the number of commercial buildings each year.

The total estimated CHP resource in the UK is 112 TWh of electricity per year, equivalent to over 25% of UK electricity consumption. Over 75% of this resource is in the domestic retrofit sector, with high run hours sites in commercial premises providing an additional 5TWh.

It is assumed that CHP systems will be installed as boiler replacements in homes or plant rooms of commercial buildings. Therefore, the maximum deployment in a given year is equal to the number of annual boiler sales in the UK, which were 1.56 million units in the domestic sector and 70,000 units in commercial buildings[32].

Table 46 Sub-50kW CHP potential in the UK

Site type	Technology	Full load run hours	Number of sites	Total potential (TWh_e per year)
New build	Domestic Stirling	600	96,000	0.1
	Domestic Fuel Cell	3000	96,000	0.3
	10kW gas engine	4500	4,500	0.2
	50kW gas engine	4500	500	0.1
Retrofit - high run hours	Domestic Stirling	3000	9,880,000	29.6
	Domestic Fuel Cell	5000	9,880,000	49.4
	10kW gas engine	6000	54,000	3.2
	50kW gas engine	6000	6,000	1.8
Retrofit - low run hours	Domestic Stirling	2000	1,560,000	3.1
	Domestic Fuel Cell	4000	1,560,000	6.2
	10kW gas engine	3000	396,000	11.9
	50kW gas engine	3000	44,000	6.6
Total	-	-	23,577,000	112.6

[32] Data from the Heating and Hot Water Industry Council