Oxera

What is the potential for commercially viable renewable generation technologies?

Interim report prepared for the Department of Trade and Industry

January 2005

Executive Summary

Renewable electricity generation will have a key role in achieving the government's long-term energy policy objectives and will need to provide a significant contribution towards the UK's CO_2 reduction targets. Since 2002, the Renewables Obligation (RO) has been the main policy instrument used to encourage electricity generation from renewable sources, providing support to renewables generators through a requirement on electricity suppliers to purchase a predefined and growing proportion of their electricity sales from renewable sources. As part of the 2003 Energy White Paper, the government committed to a review of the RO that would 'elaborate a strategy to 2020'. This report, in conjunction with a parallel analysis by Enviros Consulting, forms part of that review. It focuses on the potential, over time, for some forms of renewable electricity generation to become commercially viable without requiring support from the RO.

The economic viability of future investments in renewable electricity generation will depend on the interaction between the costs of building and operating a renewables project and the revenues it could be expected to earn. At present, the main sources of revenue for renewable generators are the wholesale electricity market, the RO and the value of Levy Exemption Certificates under the Climate Change Levy. The introduction of the EU Emissions Trading Scheme (EU ETS) at the start of this year is widely expected to result in an increase in wholesale electricity prices, thereby benefiting renewable generators whose cost base will not be affected. This additional benefit, combined with the expectation that renewable generation costs could fall over time, raises the question of whether certain technologies might reach commercial viability in the near future.

The analysis undertaken shows that the EU ETS is only expected to have a modest impact on UK wholesale electricity prices—around £2.85/MWh at current carbon allowance prices. Even with a bold assumption of carbon allowances trading at €25/tCO_2 and the full cost of these allowances being passed through into the electricity market, wholesale electricity prices would be unlikely to increase by more than £10/MWh. By comparison, the RO currently provides support of around £45/MWh to eligible technologies and hence the introduction of the EU ETS, in itself, is unlikely to mean that some forms of renewable generation will no longer need support from the RO. Therefore, the critical question of whether certain technologies could become commercially viable in the future will hinge on how the costs of these technologies will change over time.

It is generally anticipated that the capital and operating costs of some renewables technologies may fall in future. However, the renewables cost assessments developed by Enviros as part of this study have indicated that costs are unlikely to fall sufficiently for any of the existing technologies to become commercially viable over the next decade. Enviros' analysis paid particular attention to developing detailed supply curves for onshore wind and landfill gas developments. These technologies were identified as those most likely to reach commercial viability over the next decade. An analysis of these supply curves showed that, while technology improvements and economies of scale could lead to reductions in certain cost elements, the actual unit costs of electricity from these technologies may rise in the future as new projects would increasingly need to be developed at less favourable sites.

Using the cost assumptions and revenue projections developed in this study, there appears to be little scope for significant volumes of renewable generation to become commercially viable without continued support from the RO. An inspection of Table 1 shows that the 'close to market' technologies are still expected to need some additional support over the next decade in order to ensure continued investment, even allowing for the impact of the EU ETS. However, the analysis also shows that, in some cases, the level of support required could be less than that currently provided by the RO and there may be some benefit in reducing the level of support that these technologies receive.

Table 1 Level of support required for investment in each year (£/MWh)

	2005/06	2008/09	2012/13	2016/17
Landfill	9.6–22.8	6.8–51.9	7.1–57.4	7.3–47.8
Onshore wind	17.7–32.1	21.3–37.3	21.1–35.5	27.8–41.6
Hydro <1.25MW	45.2–56.3	40.2–52.4	35.8–46.5	31.6–41.5
Hydro 1.25–20MW	29.0–40.1	24.8–37.1	21.4–32.2	18.2–28.2
Hydro >20MW	40.2–51.3	37.3–49.6	35.6–46.4	33.8–43.8
Sewage gas	28.4–39.5	27.4–39.7	28.1–38.9	28.7–38.6
Offshore wind	40.1–51.3	25.6–38.4	15.7–26.7	8.7–18.7
Biomass—stand-alone	34.6–45.7	28.6–41.3	25.4–36.3	23.8–33.8

Source: Oxera.

The structure of the RO means that it provides the same level of support to all qualifying renewable technologies, regardless of the actual level of support required to reach commercial viability. By adjusting the eligibility rules for some of the close-to-market technologies, it may be possible to target this support more efficiently, thereby resulting in a greater overall volume of renewable generation without increasing the cost to consumers. The two most promising methods for reducing the level of support provided to close-to-market technologies would be:

– a reduction in the length of time over which projects remain eligible for the RO;
– a reduction in the proportion of a projects output that qualifies for the RO.

To be beneficial, the changes in eligibility would need to be carefully targeted so as to ensure that continued investment in these technologies remained profitable. Further analysis is also required to quantify the impact that changes in eligibility could have on the government's renewable energy objectives and the cost of meeting these through the RO.

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1 Introduction

Renewable energy is expected to play a vital role in achieving the government's long-term energy policy objectives.[1] Work undertaken for the government suggests that renewables will need to contribute between 30% and 40% of electricity generation for target reductions of 60% in CO_2 by 2050.[2] At present, there are a number of support mechanisms for renewables that are intended to increase investment in renewable technologies to achieve two medium-term targets:

– 10% of electricity from renewable generation sources by 2010; and
– 20% of electricity from renewable generation sources by 2020.

To put these targets into context, renewable generation accounted for only 2.8% of total UK electricity consumption in 2003.

One of the main support mechanisms, introduced in 2002, is the Renewables Obligation (RO).[3] This requires licensed suppliers to source a growing proportion of their electricity requirements from qualifying renewable generation. The RO is currently under review and this interim report forms part of a study that has been commissioned as an input to the review process.

The aim of the overall study is to analyse the potential impact that the introduction of the EU Emissions Trading Scheme (EU ETS) may have on the commercial viability of renewable technologies currently eligible for support through the RO, and the implications of any amendment to the eligibility rules that may occur as a result of changes to viability.

Commercial viability is a function of the relative levels of the costs of renewable generation and the (non-RO) revenue streams over the life of a project, both of which are subject to a high degree of uncertainty. Thus, the analysis presented in this interim report looks at both the revenue and the cost drivers that may affect the position of different technologies.

The cost analysis draws on concurrent work undertaken by Enviros Consulting as part of the same overall study,[4] deriving aggregate renewable generation supply curves over time. The revenue analysis describes the main drivers on wholesale electricity prices and constructs three broad scenarios of possible states of the world, which define a realistic range for wholesale prices over the course of the RO. As part of this, it defines the potential scale of the impact of the EU ETS on wholesale electricity prices.

Combining these two separate elements of analysis enables the conditions under which specific technologies may become commercially viable to be identified. The results illustrate both the sensitivity of full commercial viability to the underlying cost and revenue drivers and the range of uncertainty over necessary support levels for technologies over time. These results enable some initial observations to be made in relation to potential policy options, with specific reference to the impact of the nature of the RO mechanism on the likely achievement of renewable generation targets.

The remainder of the report is structured as follows:

[1] The UK government's current energy policy is outlined in the Energy White Paper, DTI (2003), 'Our Energy Future: Creating a Low Carbon Economy', February.
[2] Future Energy Solutions (2003), 'Options for a Low Carbon Future'.
[3] Other support mechanisms that increase the relative competitiveness of renewable generation include the Climate Change Levy and renewable energy support programmes.
[4] Enviros Consulting (2005), 'Costs of Supplying Renewable Energy', January.

- section 2 outlines the current position of renewables in the UK market and describes the main support mechanisms designed to incentivise renewables investment;
- section 3 presents renewable generation supply curves in aggregate and for individual technologies over the period 2005/6 to 2015/16;
- section 4 examines the main revenue drivers and presents the core analysis of the extent to which commercial viability will be influenced by changes in these drivers—in particular, the EU ETS;
- section 5 summarises some of the policy options which could be implemented if it was identified that some technologies were sufficiently close to market to merit reduced support; and
- section 6 draws out the main conclusions.

2 The renewables market

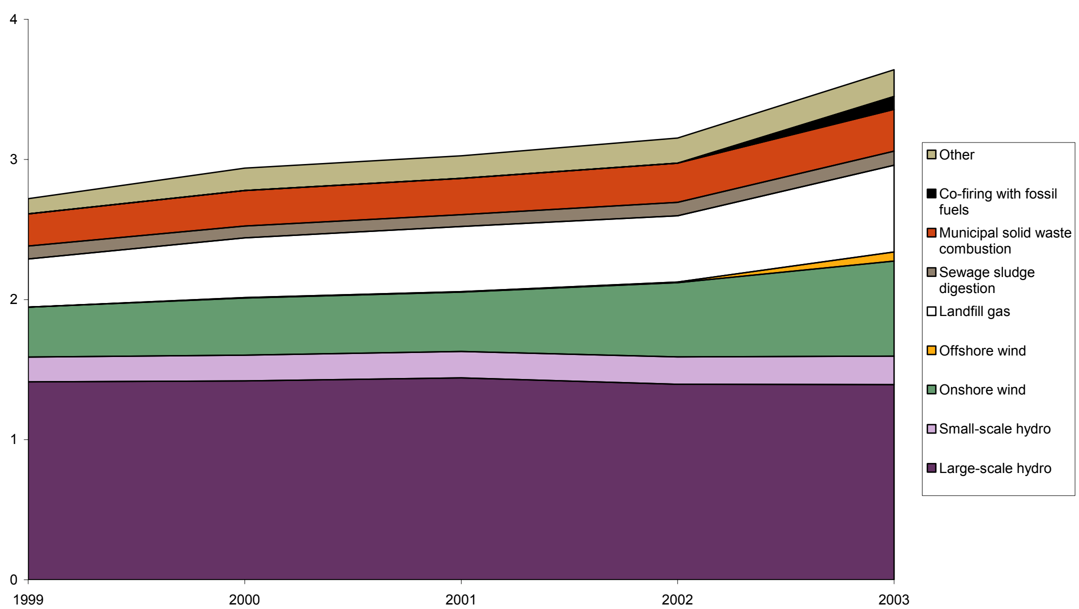
In January 2000 the government announced its aim for renewables to supply 10% of UK electricity in 2010, subject to the costs being acceptable to the consumers.[5] The Energy White Paper in 2003 reiterated this target and announced an aspiration for renewables to supply 20% of electricity by 2020.[6]

At present, renewable generation represents a relatively small share of the capacity and output of the generation sector, although the contribution has been increasing gradually over time in conjunction with the introduction of various support mechanisms. Before considering the future prospects for renewable generation, a brief overview of the current position is presented, together with a description of the main support mechanisms—in particular, the RO.

2.1 Capacity and generation

The total installed capacity of renewable generation in the UK has grown by 34% in four years, from 2,720MWe in 1999 to 3,640MWe in 2003, as shown in Figure 2.1. This latter figure represents around 4.5% of the total installed capacity in the UK in 2003.[7]

Figure 2.1 Installed capacity of renewable generation in the UK, 1999–2003 (GWe)



Notes: The 'shoreline wave' and 'solar photovoltaic' categories are included in the 'Other' category. 'Large-scale hydro' covers plants belonging to companies with an aggregate hydro capacity of 5MWe and above.
Source: DTI (2004), *Digest of UK Energy Statistics*, Table 7.4, July.

The majority of this capacity is in large-scale hydro facilities, which comprise 38% of the 2003 installed capacity. However, this capacity has been relatively constant over the period and the increase can largely be attributed to growth in three key areas:

[5] DTI (2000), 'Conclusions in response to public consultation—New and Renewable Energy: Prospects for the 21st Century'.

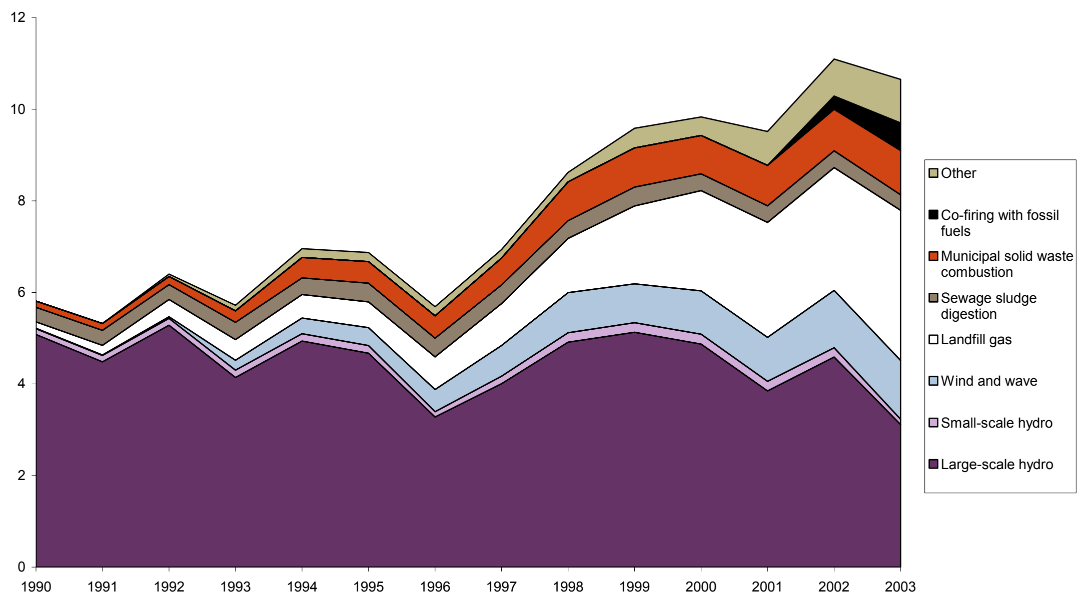
[6] DTI (2003), 'Our Energy Future: Creating a Low Carbon Economy', February.

[7] According to the *Digest of UK Energy Statistics*, the total capacity was 80,742 MW in 2003.

– landfill gas, the capacity of which grew by 80% (from 343MWe to 619MWe) between 1999 and 2003;
– wind farms, where capacity has more than doubled since 1999, largely through growth in onshore wind farms; and
– the development of co-firing capacity, which in 2003 provided 2.5% of total renewable capacity.

As installed capacity has increased, so has the output of renewable generators. Figure 2.2 shows the growth in renewable output by technology over the period from 1990 to 2003. In this period, renewable generation in the UK increased by 83%, from 5,811GWh in 1990 to 10,649GWh in 2003. Between 1999 and 2003, renewable generation increased by 11%, from 9,581GWh in 1999 to 10,649GWh in 2003. By 2003 renewable generation was approximately 2.8% of the total generation in the UK.[8]

Figure 2.2 Renewable generation in the UK, 1990–2003 (TWh)



Notes: 'Solar photovoltaic' has been included in the 'Other' category. 'Large-scale hydro' covers plants belonging to companies with an aggregate hydro capacity of 5MWe and above.
Source: DTI, *Digest of UK Energy Statistics*, Table 7.1.1.

As Figure 2.2 shows, the shares of capacity and output are not the same. This is because of differences in the load factors achievable for each of the technologies. Thus, while wind farms represent around 20% of total capacity in 2003, they have a lower share, around 12%, of total output. By contrast, generation from co-firing represents 2.5% of capacity and 5.7% of output.

2.2 Regulatory and policy framework

The observed growth in renewable generation has occurred against a background of ongoing regulatory and policy support through several instruments, including:

– the Non Fossil-Fuel Obligation (NFFO);
– the Climate Change Levy (CCL);
– the RO;

[8] DTI (2004), *Digest of UK Energy Statistics*, Table 7.4, July.

– other support instruments—such as the Capital Grants Scheme and the New and Renewable Energy Programme.

The key aspects of each instrument are described below. Most emphasis is placed on the RO mechanism, as the operation of this instrument is the focus of this analysis.

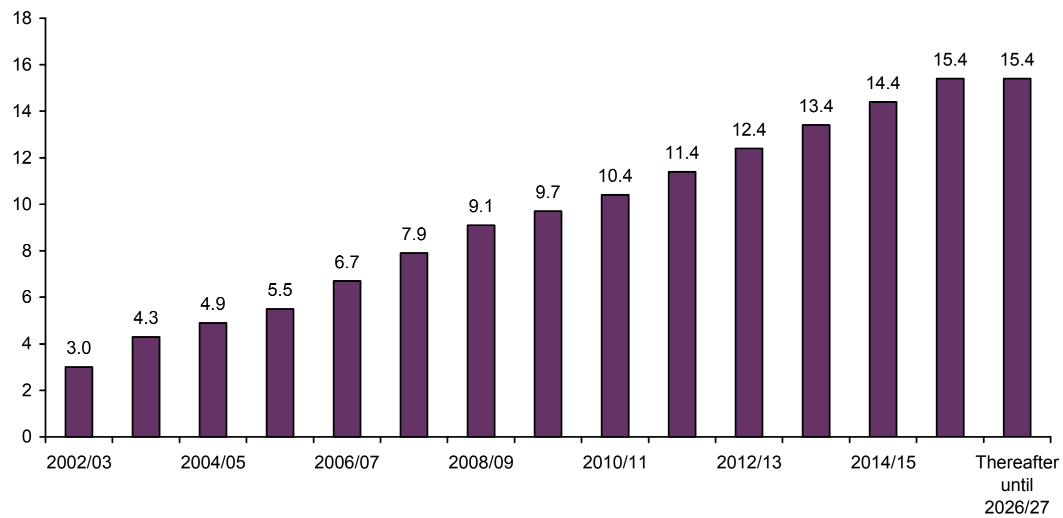
2.2.1 Renewables Obligation

The RO is intended to support the development of renewable electricity generation by requiring all licensed electricity suppliers in England and Wales to purchase a specified and rising proportion of their electricity sales from renewable sources of generation. Electricity suppliers in Scotland are subject to a parallel obligation, the Renewables Obligation for Scotland (ROS), and the government intends to introduce a Northern Ireland Renewables Obligation from April 1st 2005.

Obligation size

Originally set to increase annually up to 10.4% by 2010/11, the government has recently concluded a statutory consultation on changes to the RO; one change is to expand the size of the RO to 15.4% by 2015/16 (see Figure 2.3).[9]

Figure 2.3 Renewables Obligation size (% of supplier volumes)



Source: DTI (2004), 'Renewables Obligation Order 2005 Statutory Consultation Document', September.

Renewables Obligation Certificates and compliance

Ofgem is responsible for administering the RO policy. Suppliers must show compliance by surrendering Renewables Obligation Certificates (ROCs), which each represent 1MWh of renewables generation. Ofgem issues accredited renewable generators with a ROC—or Scottish ROC (SROC), in the case of Scottish generators—for each 1MWh of renewable generation produced. Suppliers can purchase ROCs directly from a generator or by trading with other market participants.

If a supplier has not purchased sufficient ROCs/SROCs by the end of a compliance period, it will be charged an administered buyout price for any outstanding obligation volumes. Initially set at £30/MWh, the buyout price is due to increase annually in line with inflation, as shown in Table 2.1.

[9] DTI (2004), 'Renewables Obligation Order 2005 Statutory Consultation Document', September.

Table 2.1 Buyout price (£/MWh)

Financial year	Buyout price (£/MWh)
2002/03	30.00
2003/04	30.51
2004/05	31.39

Source: www.ofgem.gov.uk (Renewables information site, under 'Supplier compliance').

Up to 25% of a supplier's obligation may be met by ROCs awarded in the previous period (a process known as 'banking'); however, no borrowing is permitted (ie, bringing forward ROCs from future periods).

Eligible technologies

Table 2.2 lists the renewables technologies that are eligible for ROCs.[10]

Table 2.2 Sources of electricity eligible for the Renewables Obligation

Source	Eligible?
Landfill gas	Yes
Sewage gas	Yes
Energy from waste	Only pure biomass or fuels derived from waste using advanced technologies
Hydro exceeding 20MW	Only stations commissioned after April 1st 2002
Hydro 20MW or less	Yes
Onshore wind	Yes
Offshore wind	Yes
Other biomass—eg, agricultural and forestry residues	Yes
Geothermal power	Yes
Tidal and tidal stream power	Yes
Wave power	Yes
Photovoltaics	Yes
Energy crops	Yes
Biomass co-fired with fossil fuels	Yes, but subject to the restrictions discussed below

Source: DTI (2001), 'The Renewables Obligation Statutory Consultation,' August.

There are additional rules for power derived from biomass co-fired with fossil fuels. The proportion of ROCs sourced from co-firing by an individual supplier is capped at 10% of that individual supplier's obligation from April 1st 2006 to March 31st 2011, and at 5% from April 1st 2011 to March 31st 2016. After this date, co-firing will cease to be eligible for ROCs. Furthermore, there are rules governing the minimum proportion of biomass that must be derived from dedicated energy crops, as set out in Table 2.3.

[10] Only stations commissioned after December 31st 1989 are eligible.

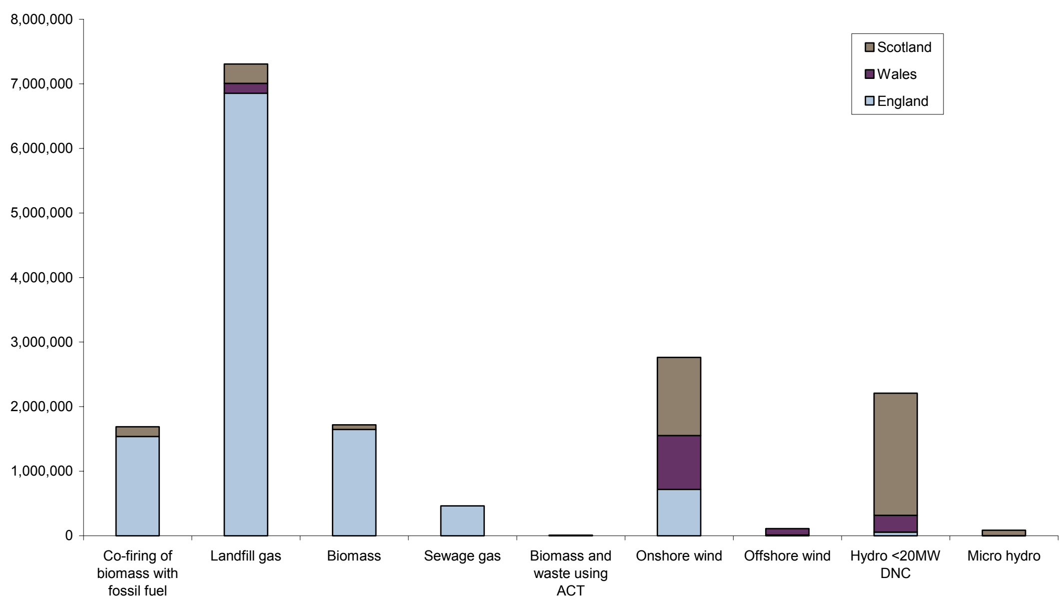
Table 2.3 Minimum energy crop content for biomass used in co-firing

Time period	Minimum energy crop content (%)
2002/03 to 2008/09	No minimum percentage
2009/10	25
2010/11	50
2011/12 to 2015/16	75

Source: DTI (2004), 'Renewables Obligation Order 2005 Statutory Consultation Document', September.

The total number of ROCs issued since the RO began in April 2002 until August 2004 was 16,359,287, equivalent to 16,359GWh of renewable energy. Of this, 11,304GWh was generated in England, 1,345GWh in Wales and 3,709GWh in Scotland. Figure 2.4 shows the split of ROCs issued in 2003/04 by technology, as well as by country.

Figure 2.4 Renewable energy generated by technology and country, April 2003–March 2004



Source: Ofgem (2004), 'List of accredited generating stations (RO and CCL)', December.

Recycling of the buyout fund and the price of ROCs

Within each annual compliance period, the buyout payments made by suppliers with insufficient ROCs are collected by Ofgem to form a buyout fund, which is then recycled back to ROC/SROC holders. The value of this fund depends on the volume of ROCs issued relative to the obligation size in a given compliance period, and the buyout price. When the volume of qualifying generation, and hence the number of ROCs issued, is greater or equal to the size of the obligation, suppliers will not need to use the buyout mechanism to meet their obligation and hence there will be no buyout fund. However, if the number of ROCs issued is less than the size of the obligation then the buyout fund can be estimated by the following equation.

$$\text{buyout fund} = \text{buyout price} * (\text{obligation size} - \text{no. of ROCs issued})$$

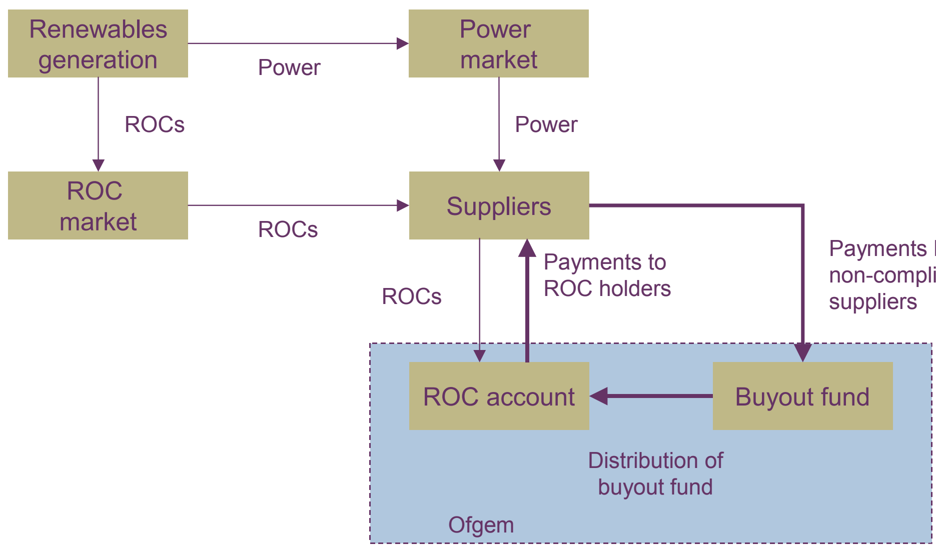
In situations where a buyout fund exists, it is recycled back to suppliers in proportion to the volume of ROCs they used in meeting their obligation. Therefore, the size of dividend provided to each ROC holder is the buyout fund divided by the number of ROCs issued. For a given obligation size, increasing the total number of ROCs issued will decrease the buyout dividend, and decreasing the volume of ROCs will increase it. The implication of this interaction between the recycling mechanism and the buyout price is that the actual market value of a ROC could be higher or lower than the buyout price, depending on the qualifying volume of ROCs issued relative to the total size of the RO.

If the volume of ROCs issued is less than the obligation size, some suppliers will be forced to pay into the buyout fund. As this fund is recycled back to suppliers that used ROCs to meet their obligations, the value of a ROC will be higher than the buyout price by the extent of the ROC dividend, as described above.

However, if there are excess ROCs in the market then no buyout payments will be required and some generators will not be able to sell their full volume of ROCs. This would lead to ROC values falling below the buyout price. In a competitive market, the value of ROCs would be expected to fall sharply once the qualifying volume exceeded the obligation size.

The Renewables Obligation system is summarised in Figure 2.5.

Figure 2.5 The Renewables Obligation system



2.2.2 Non-Fossil Fuel Obligation

The NFFO was the government's previous major instrument for encouraging growth within the renewable energy industry before the introduction of the RO. It applied in England and Wales, with counterparts in Scotland and Northern Ireland: the Scottish Renewables Obligation (SRO) and the Northern Ireland NFFO (NI NFFO). These required electricity supply companies in the UK to secure specified amounts of new generating capacity from non-fossil sources, including renewables. This capacity was secured through contracts with non-fossil fuel generators at premium rates. The Non-Fossil Purchasing Agency (NFPA) was set up to act as an agent between suppliers and renewables generators, with generators submitting tenders to the NFPA for proposed renewables projects and the costs of projects being covered through a Fossil Fuel Levy.

In total, five NFFO, three SRO and two NI NFFO Orders were issued between 1990 and 1999, covering 933 projects and a total of 3,638MW of capacity, as detailed in Table 2.4 below. Of these, 421 projects remained live as at September 2004, representing around 1,032MW of renewable capacity. Electricity from generators built under the NFFO arrangements is eligible for the RO. However, where the output is still covered by an NFFO contract, the ROCs will be issued to the NFPA, which will use the funds generated from selling these ROCs to offset the costs of the Fossil Fuel Levy.

Table 2.4 The NFFO Orders

Order	Year	MW (dnc)[1]
NFFO 1	1990	152
NFFO 2	1991	472
NFFO 3	1994	627
NFFO 4	1997	843
NFFO 5	1998	1,177
SRO 1	1994	76
SRO 2	1997	114
SRO 3	1999	145
NI-NFFO 1	1994	16
NI-NFFO 2	1996	16

Note: [1] 'dnc' is a measure of electrical capacity that takes into account the intermittent nature of power output from some renewable sources, and is equivalent to the installed capacity multiplied by a factor between zero and one. For example, for wind, the factor is 0.43.
Source: DTI (2004), 'NFFO factsheet 11'

Specific technologies were excluded from the NFFO as they approached competitiveness in the open market and no longer needed financial support, while promising new technologies could become eligible when they showed potential to become competitive. Eligibility varied between the NFFO Orders, as shown in Table 2.5.

Table 2.5 Eligibility under the five NFFO Orders in England and Wales

NFFO 1	NFFO 2	NFFO 3	NFFO 4	NFFO 5
Wind	Wind	Wind >1.6MW	Wind >0.768MW	Wind>0.995MW
		Wind <1.6MW	Wind <0.768MW	Wind <0.995MW
Hydro	Hydro	Hydro	Small-scale hydro	Small-scale hydro
Landfill gas	Landfill gas	Landfill gas	Landfill gas	Landfill gas
Municipal & industrial waste	Municipal & industrial waste	Municipal & industrial waste	Waste-fired fluidised bed combustion	Energy from waste
Sewage gas	Sewage gas		Waste-fired CHP	Energy from waste using CHP
Other	Other		Anaerobic digestion of agricultural wastes	
		Energy crops and agricultural & forestry waste	Biomass gasification or pyrolysis	

Source: UK Parliament website.

2.2.3 Climate Change Levy

Introduced on April 1st 2001, the CCL is a tax on the use of energy in industry, commerce and the public sector, with offsetting cuts in employers' National Insurance Contributions and additional support for energy efficiency schemes and renewable sources of energy. The CCL does not apply to domestic energy use, energy used by registered charities for non-business uses, or energy used by very small firms (ie, those using a small amount of energy).

There are several exemptions from the CCL, including:

- electricity generated from ‘new’ renewable energy (eg, solar and wind power);
- fuel used by ‘good quality’ CHP schemes (as certified by the CHP Quality Assurance Programme, or CHPQA);
- fuels used as a feedstock;
- electricity used in electrolysis processes, such as primary aluminium smelting;
- fuels used by the domestic or transport sector;
- fuels used for the production of other forms of energy (eg, electricity generation) or for non-energy purposes;
- oils, as these are already subject to excise duty.

The levy imposes a cost on non-domestic electricity users of £4.3/MWh, which is administered through HM Customs & Excise. As electricity produced from renewable sources is exempt from the CCL, electricity users can reduce the amount of levy they pay by providing evidence that some of their electricity consumption has come from renewable sources. This process is facilitated through the use of Levy Exemption Certificates (LECs). Accredited renewable electricity generators receive LECs equivalent to their output, which can then be used by electricity consumers as evidence that a proportion of their energy use has come from renewable sources. This means that electricity users should be prepared to pay a premium of up to £4.3/MWh for electricity from renewable generators, though in practice there may be some sharing of the benefit between the renewable generator and the electricity user.

2.2.4 Other support mechanisms

Under the New and Renewable Energy Programme, funding is available to support the development of new and renewable energy sources, including fuel cells, offshore wind, wave and tidal power, photovoltaics and biomass. There is a two-stage assessment process—outline proposals followed by full proposals—with independent assessors involved at each stage.

The New and Renewable Energy Programme is being incorporated into the DTI’s Technology Programme, and will be delivered through the new Collaborative R&D business support product. The process for the handling and assessment of proposals under the Collaborative R&D business support product will remain broadly similar to that followed under the New and Renewable Energy Programme, although there is a change to the eligibility rules for applicants. To be eligible for support, all proposals must be of a collaborative nature, with collaborators being defined as those bodies that directly incur and bear part of the costs and risks of the project. The role of the collaborator goes beyond that of a sub-contractor, and collaborators have the right to use the results of the project for further internal research or teaching.

The DTI’s Capital Grants Scheme funds demonstration projects to help reduce the costs and the risks involved in such developments, and to maximise the contribution to the government’s targets for renewable electricity supply within the UK. The New Opportunities Fund is also contributing £50m to renewable energy projects. The funding provided by these schemes has been used in a variety of initiatives, including:

- offshore wind projects—the primary aim is to stimulate early development of a significant number of offshore wind farms, providing a learning experience which will increase confidence and reduce further costs. In the first and second rounds, a total of £117m has been awarded;

- projects generating electricity from energy crops and small-scale biomass heating schemes—the aim is to encourage the efficient use of biomass and particularly energy crops for energy production by stimulating the early development of biomass-fuelled heat and electricity generation projects. The DTI is making £30m available and the New Opportunities Fund is providing at least £33m for power generation from energy crops and at least £3m for small-scale biomass/CHP projects. Defra is also running the energy crops scheme which has £29m available and will run until 2006;

– development of marine renewables—the ‘Marine Renewables Deployment Fund’ worth £50m was set up to help realise the potential for the development of marine renewable technologies such as wave and tidal power;

– photovoltaics—in 2002 the first phase of the Major Photovoltaics Demonstration Programme was launched, at a cost of £31m. This provides grants to individuals and organisations wanting to install solar electric (photovoltaic) systems in homes and other buildings over the next three years; and

– community and household renewables—the £12.5m Clear Skies Initiative provides grants and advice to encourage homeowners and communities to become familiar with renewable energy options.

3 Potential for renewables

While it is generally accepted that there is a significant potential for renewable electricity generation in the UK, the crucial consideration for this review of the RO, and for government energy policy in general, is how much of this potential can be practically and economically exploited. The work being carried out concurrently by Enviros as part of this study has attempted to address this question by analysing the resource size and costs for the main renewable generation technologies likely to contribute to the UK's generation mix within the next ten to 15 years.[11] In particular, the analysis has focused on providing a detailed picture of the potential scope for, and the costs of, developing the UK's onshore wind and landfill gas resources. The focus has been on these technologies as they are the closest to becoming commercially viable and are likely to represent a significant proportion of the UK's renewable generation over the next decade.

In addition to the detailed studies of the onshore wind and landfill gas resource, Enviros has provided a higher-level analysis of the resource potential and likely costs for:

– offshore wind;
– photovoltaics;
– tidal;
– wave;
– sewage gas;
– generation from biomass;
– gasification of mixed wastes;
– micro-, small- and large-scale hydro generation.[12]

The Enviros report also briefly looks at the costs and potential of co-firing biomass with fossil fuels. However, biomass co-firing has not been covered in this Oxera analysis, as the revised rules for co-firing announced in December 2003 will result in a declining contribution to the RO from this technology over the next decade. Alterations to these rules have been explicitly excluded from the scope of the RO review. In addition, the requirement for a rising proportion of biomass fuels used in co-firing to come from dedicated energy crops (see Table 2.3) is likely to see the costs of co-firing increasing over time, thereby limiting the potential for any further beneficial changes in the RO rules regarding co-firing.

3.1 Drivers of resource potentials and costs

In addition to the project-specific capital and operating costs, there are several generic drivers that will affect both the overall costs of renewable generation and the size of the realisable resource. The most significant of these are:

– the cost of capital (or return on investment required for project);
– the potential for cost reductions over time; and
– limitations on the build rates for renewables projects.

3.1.1 Cost of capital

The development of renewable generation projects tends to be capital-intensive, typified by large up-front costs to purchase and install plant, and project lifetimes of between ten and 25

[11] Enviros Consulting (2005), 'The Costs of Supplying Renewable Energy', January.

[12] The definitions used for micro-, small- and large-scale hydro generation are consistent with the Renewables Obligation Order and are less than 1.25MW, 1.25–20MW and greater than 20MW respectively.

years. As most renewable generation projects do not have significant ongoing fuel costs, the cost of financing the initial capital investment represents a high proportion of the ongoing costs for a renewable generator—hence, the cost of capital becomes an important driver on the cost of renewable generation.

Through discussions with the industry, Enviros has assessed that the costs of capital employed by renewables developers are likely to be related to the degree of risk associated with each type of technology. For example, landfill gas and onshore wind are now largely established technologies, for which it is possible to secure debt financing for a significant proportion of the project costs. By contrast, the development costs and lifetimes for offshore wind projects are less certain and are likely to require a greater degree of equity finance and therefore incur higher finance costs. In practice, there is likely to be some variation in the investment hurdle rates required for different developers and different types of investment; however, Enviros has used the simplifying assumption that the more established technologies will be able to secure 75% debt finance, while riskier technologies will only be able to achieve 45% debt finance. Using cost of debt and equity assumptions of 6.5% and 18% respectively results in the base-case cost of capital assumptions as estimated by Enviros (see Table 3.1). A high-case sensitivity has also been provided, assuming a lower proportion of debt financing and higher cost of equity.

Table 3.1 Cost of capital assumptions (%)

	Base scenario	High case sensitivity
Landfill gas	7.9	9.2
Onshore wind	7.9	9.2
Offshore wind	11.9	13.1
Photovoltaics	11.9	13.1
Tidal	11.9	13.1
Wave	11.9	13.1
Gasification of wastes	11.9	13.1
Biomass	11.9	13.1
Micro hydro (<1.25MW)	7.9	9.2
Small hydro (1.25–20MW)	7.9	9.2
Sewage gas	7.9	9.2

Source: Enviros.

3.1.2 Learning rates

In addition to variations in the static cost assumptions, the underlying cost of renewable generation technologies will be expected to change over time. This process is usually represented through the application of a progress ratio (see Box 3.1). The figures for the progress ratios assumed in this analysis are given in Table 3.2.

Box 3.1 Learning rates and progress ratios

Over time, the cost of developing renewable generation projects is expected to fall due to the realisation of economies of scale and technological effects, such as learning by doing. It is important to capture this phenomenon in any projection of supply curves for renewable technologies, as it introduces a dynamic change to supply curves over time.

A common method of describing such cost changes is through a learning rate—ie, the percentage that the cost of production falls with each doubling of the total number of units produced. The same concept is often presented as a progress ratio (PR), which is equal to 1 – learning rate, and is the percentage of initial costs that current costs will be at following a doubling of output. For example, a PR of 80% means that costs are reduced by 20% each time the cumulative production is doubled.

Evidence of learning

PRs have been estimated from historic data in a number of academic and policy studies. Many of these studies have focused on onshore wind technologies (due to the greater availability of data), and have estimated PRs in the range 81–101%, as illustrated in the table below. (A PR of greater than 100% implies that costs would rise over time as the volume of capacity grew.) The range of 81–101% is significant in terms of renewables policy as small differences in PR of a few percent can have large effects on the investment needed to bring technologies to the commercial stage. Two possible explanations for this variation are that the studies are looking at different cost components of onshore wind, and they are focusing on different time periods.

Onshore wind components	Historic progress ratio (%)	Period
Wind turbines[1]	92–98	1982–1997
Wind turbines (150–225kW)[1]	100–101	1987–1997
Wind turbines (> 55kW)[1]	95	1990–1997
Wind turbines (> 55kW)[2]	96	1982–1995
Capital costs[3]	81, 85	1990–2001
Capital costs[4]	90	'recent years'
Cost of generation[2]	91	1980–1991
Cost of generation[5]	82	1980–1995

Sources: [1] Neij (1997), 'Use of experience curves to analyse the prospects for diffusion and adoption of renewable energy', *Energy Policy*, **23**:13, 1099–107, [2] Neij (1999), 'Cost dynamics of wind power', *Energy*, **24**, 375–89. [3] Junginger, Faaij & Turkenburg (2003), 'Global experience curves for wind farms', *Energy Policy*, **33**, 133–50, [4] Garrad Hassan (2003), 'Offshore wind: Economies of scale, engineering resource and load factors', report prepared for DTI and the Carbon Trust, [5] International Energy Agency (IEA) (2000), Experience curves for energy technology policy', Paris: OECD, and Performance and Innovation Unit (2001), Technical and economic potential of renewable energy generating technologies: Potentials and cost reductions to 2020'. Oxera calculations.

As noted above, the PRs reported vary in the cost elements they capture and in the period over which data has been taken. Turbine costs may exhibit a different PR to other elements of capital or operation and maintenance (O&M) costs due to the scope for cost savings and innovation, the ability to apply experience from other sectors and activities, and the overall maturity of the development of the technology.

One of the main findings of academic studies is that PRs may indeed differ at each stage of development. For example, it has been suggested that the PR of gas turbines was 80% in the RD&D phase, and 90% in the commercialisation phase (Junginger et al, 2003). As technologies mature, the scope for cost reductions may decline.

Projected learning

A number of studies go further and set out their assumptions on what the PRs will be in the future. The table below summarises projected PRs of energy technologies found in the literature.

Technology	Projected PR (%)	Time period
Onshore wind: capital cost[1]	83–91	up to 2010
Offshore wind: capital cost[2]	90	'long term'
Offshore wind: cost of generation[3,4]	80–85	
Wave and tidal stream[4]	80–85	
Biomass energy crops[3]	85	

Sources: Oxera calculations. [1] European Wind Energy Association (2004), 'The cost of wind power', *Renewable Energy World*, July–August. [2] Hassan (2003). [3] IEA (2000). [4] PIU (2001).

Table 3.2 Progress ratios (%) assumed in the analysis

	Base scenario	High case sensitivity
Onshore wind		
Technology	92	92
Project development	90	90
Planning permission	110	110
O&M	90	90
Landfill gas		
Capital cost of 1MW engine	92	92
Capital cost of 0.22MW engine	85	85
Capital cost of retrofitting a cap	85	85
Capital cost of installing pipes wells and extraction equipment	85	85
Project development	90	90
Planning permission	100	100
O&M	90	90
Offshore wind	85	90
Photovoltaics	85	90
Tidal	85	90
Wave	85	90
Gasification of wastes	85	90
Biomass	85	90
Micro hydro (<1.25MW)	90	90
Small hydro (1.25–20MW)	90	90
Hydro >20MW	95	95
Sewage gas	92	92

Source: Enviros.

3.1.3 Constraints on build rates

Although the total size of renewable resources in the UK is potentially large, there are some practical constraints on the rate at which projects can be brought on line in order to exploit these resources. Examples of such constraints include manufacturing limitations for key components, a limited supply of specific equipment or skilled labour needed to construct projects, delays in obtaining planning consents, or restrictions owing to lack of transmission capacity or available capital.

Although it is difficult to quantify the constraints on renewable build rates, Enviros has used historical build rates and discussions with the industry to provide an estimate of maximum limits on the annual average build rate for each renewable technology considered in this report (see Table 3.3 below).

Table 3.3 Assumed maximum annual build rates

	Maximum build rate (MWe/yr)
Landfill gas	100
Onshore wind	600
Offshore wind	1000
Photovoltaics	10
Tidal	10
Wave	10
Gasification of wastes	10
Biomass	70
Micro hydro (<1.25MW)	4
Small hydro (1.25–20MW)	50
Large hydro (>20MW)[1]	70
Sewage gas	10

Note: [1] For 'Large hydro' there are estimated to be four potential projects, each of around 70MW.
Source: Enviros.

The build-rate assumptions for the less well-established technologies—solar potovoltaics, tidal and wave power—are particularly difficult to estimate. In these cases, a conservative estimate has been taken, and it may be possible to exceed these rates as the technology matures. The assumption used for the maximum build rate for offshore wind projects is consistent with analysis carried out by the consultants Garrad Hassan in 2003 for the DTI's renewables innovation review.[13]

3.2 Renewable generation supply curves

Most previous studies of renewable generation have relied on single estimates for the total cost of building and operating different types of technology. However, in practice, the costs of a certain type of renewable generation will vary according to the characteristics of individual sites. The most obvious example of this is onshore wind, where the average wind speed of the site being considered will determine expected output, and hence the project cost per unit of electricity generated. In general, it is expected that the most favourable sites for renewable generation will be developed first, as these will offer the highest returns to investors. Therefore, when assessing the costs and resource potential for renewable technologies, it is useful to consider a supply curve of potential developments, reflecting the fact that unit costs may rise as the cumulative installed capacity of a particular technology increases and the more favourable sites begin to be fully utilised.

For this analysis, Enviros has constructed detailed supply curves for both landfill gas and onshore wind generation, taking into account specific limitations on the availability of particular types of site within each generation capacity type. For the other renewable technologies, where either less information is available, or it is less likely to be a significant contributor to overall renewable generation in the medium term, a simpler analysis has been conducted based on average expected costs for that type of generation.

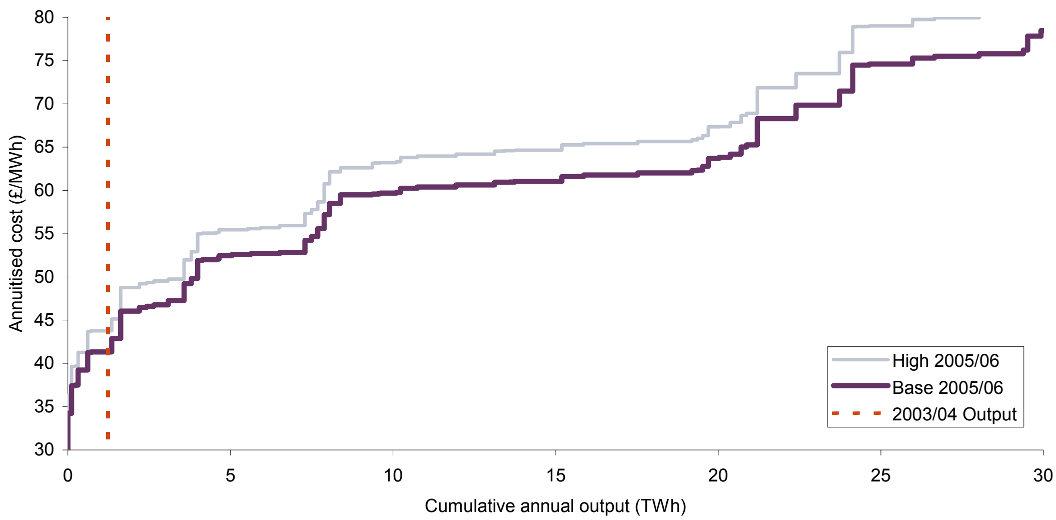
In all cases, cost estimates have been calculated on the basis of the cost per unit of output in order to allow for a simple comparison between technologies and against other measures such as electricity and ROC prices. Similarly, capacities are shown as annual MWh of electrical output so as to adjust for differences in expected plant load factors.

[13] Garrad Hassan (2003), 'Offshore wind: Economies of scale, engineering resources and load factors', December.

3.2.1 Onshore wind

The estimated supply curve for onshore wind has been built up by Enviros from estimates of the availability of allowable wind farm sites on a regional basis throughout the UK, separated into nine average wind speed categories. For each region and wind speed category, an estimate was made of the number of large (80MW) and small (30MW) wind farms that could be supported. These load factors and output characteristics of each of these projects were calculated and combined with the cost estimates to form the points on the supply curve shown in Figure 3.1.[14] The figure shows the supply curve under the base cost and output assumptions, as well a high scenario based on variations in the cost of capital and learning rate. Also shown in the figure is the level of output produced by onshore wind generation during the 2003/04 RO compliance period.[15]

Figure 3.1 Estimated total supply curve for onshore wind in 2005/06



Source: Enviros and Oxera calculations.

Enviros' analysis of onshore wind generation estimates that the total size of the potential resource could exceed 30TWh per annum. However, to exploit this level of potential, unit costs would increase significantly as the more favourable sites become fully utilised. A significant driver of the unit costs of electricity from onshore wind is the average wind speed at the project site, with lower average wind speeds resulting in lower load factors and hence higher costs per unit of output.

In general, it is reasonable to assume that existing wind farms have been built at the most favourable sites—ie, those with higher wind speeds. Therefore, the unit costs of additional onshore wind projects can be expected to rise as lower-wind-speed sites are utilised. Figure 3.1 indicates that the unit cost of additional onshore wind capacity is currently around £40–£45/MWh; however, these costs will rise as the volume of additional capacity increases.[16] For example, the unit costs of additional capacity above 20TWh per year would be greater than £60/MWh.

Although Figure 3.1 indicates a significant potential resource from onshore wind, constraints on the rate at which projects can be developed (see discussion in section 3.1.3) mean that

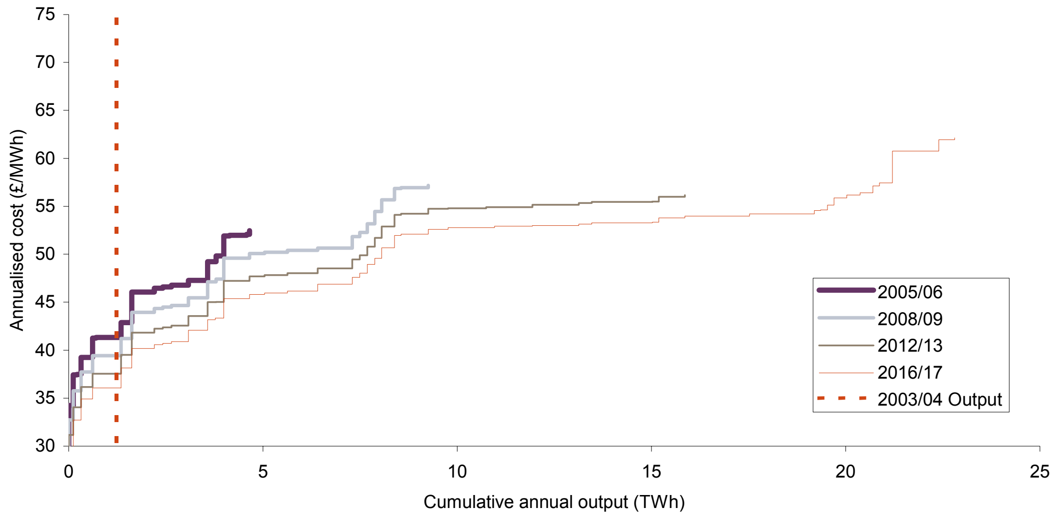
[14] The cost estimates do not include the costs of imbalance.

[15] Source: Ofgem (2004), 'List of accredited generating stations (RO and CCL)', December.

[16] The unit costs for existing wind generators are likely to be greater than £40/MWh due to the lower efficiencies and higher costs of wind generators in the past. The unit cost estimates shown in Figure 3.1 are on the basis of the costs and technical parameters of newly installed equipment.

there is a limit on the maximum potential realisable at any given point in time. For example, using the maximum annual build-rate assumption of 600MW means that the realisable potential in 2005/06 would be limited to 4.2TWh. However, by the end of 2008/09, the maximum realisable annual output could rise to just under 10TWh. This is illustrated in Figure 3.2, which shows the supply curve for the maximum capacity that would be realisable by 2005/06, 2008/09, 2012/13 and 2016/17. In addition to the increases in capacity over time, there is a downward shift in costs, reflecting the impact of the 'learning by doing' assumptions on expected costs.

Figure 3.2 Base supply curve for realisable onshore wind potential, 2005–16



Source: Enviros and Oxera calculations.

3.2.2 Landfill gas

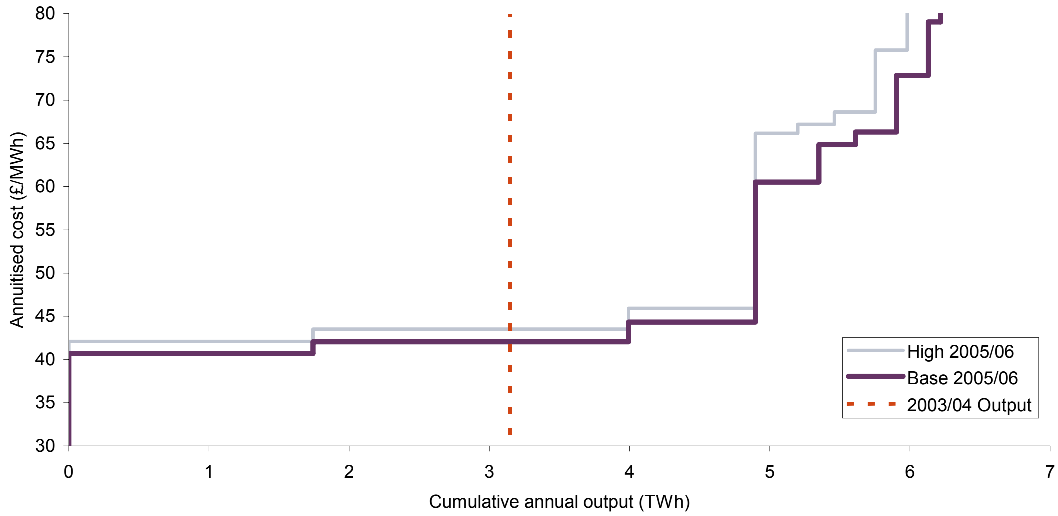
Enviros' modelling of the supply curve for generation from landfill gas is based on a simulation of the volume of methane produced from landfill sites throughout the UK and the incremental costs involved in capturing and using this gas for electricity generation. Landfill sites have been typified according to the age of the landfill and the quality of the site design—in particular, the degree and quality of the cover placed on top of and around the base and sides of the landfill. The Landfill Regulations (2002) require all sites open after July 1st 2001 to collect the gas emitted from the site and either flare it or, where economically feasible, use it to produce energy. These regulations have a significant effect on the economics of electricity generation from new landfill gas sites. This is because the costs of generation should reflect only the incremental cost of installing generators, not the full cost of capturing the gas, as gas capture is required under the Landfill Regulations, regardless of whether the gas is being used for electricity generation.

As a result of these regulations, there is a significant volume of relatively cheap landfill gas generation, although much of this is already being exploited (see Figure 3.3). Once this potential from the newer sites has been fully utilised, the costs of developing additional landfill generation rise significantly as this would be based on older sites, where capture and flaring are not required and would therefore necessitate the retrofitting of caps and other equipment.

Another important feature of the supply curve for generation from landfill gas is that the resource potential will depend on the level of gas produced from landfill sites. In turn, this will be a function of the total landfill arisings and the assumed calorific value of the gas produced.

Variations in these assumptions, along with the assumed costs of capital, give rise to the difference between the base and high supply curves.

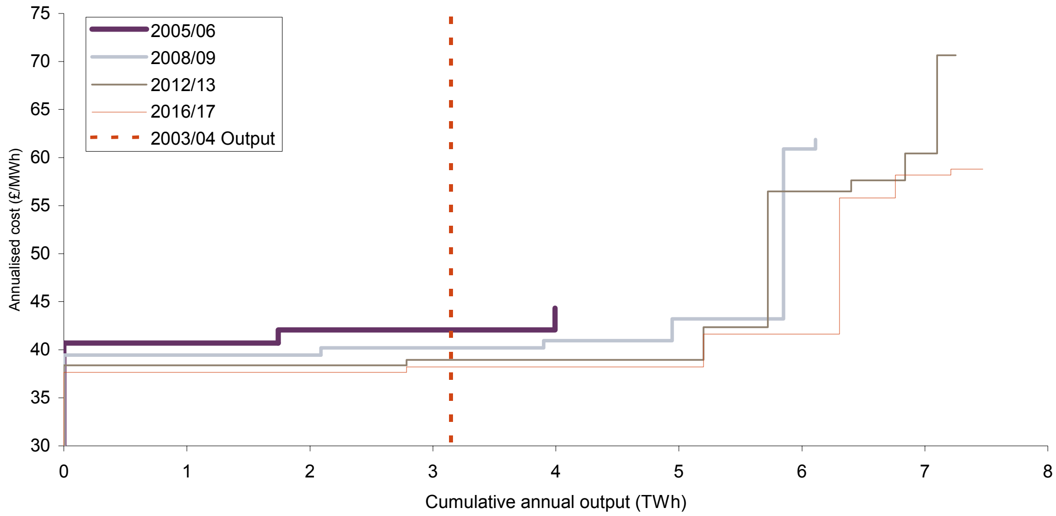
Figure 3.3 Landfill gas supply curve sensitivities, 2005/06



Source: Enviros and Oxera calculations.

Growth in landfill arisings and the impact of the Landfill Regulations also have an influence on how the supply curve for landfill gas is expected to change over time. All future landfill arisings will go to sites where landfill gas collection systems are required as part of the Landfill Regulations and hence will contribute to the volume of 'cheaper' landfill gas capacity available. The analysis by Enviros anticipates that future gas production from new landfill arisings will outweigh the decline in gas from existing sites, therefore resulting in a net increase over time in the potential capacity available from cheaper landfill sites. However, weighed against this are the build-rate assumptions of Table 3.3, which limit the maximum realisable resource in any given year. Additionally, as with onshore wind generation, costs are expect to fall over time as a result of learning. The overall effect of these influences on the landfill gas supply curve can be seen in Figure 3.4, which shows the current costs of landfill gas generation to be just over £40/MWh. Increases in the resource potential of cheaper sites mean that the volume of generation available at this price will continue to increase. However, as this potential is limited, unit costs would have to increase, to around £60/MWh by 2008/09, in order for generation from landfill gas to continue to grow at the assumed maximum build rate.

Figure 3.4 Base supply curve for realisable landfill gas potential, 2005–2016



Source: Enviros and Oxera calculations.

3.2.3 Other renewable generation technologies

The analysis of resource potentials and costs for the other forms of renewable generation did not create detailed supply curves; rather, estimates were made of the maximum realisable resource size and average costs of exploiting that resource. The maximum realisable resource estimates, shown in Table 3.4, are based on historical output in 2003/04, the maximum annual build-rate assumptions shown in Table 3.3, and the total estimated resource size. These provide an estimate of the maximum level of output from each technology type that could be achieved by a given year. For example, with a maximum build rate of 1GW per year, the annual output from offshore wind generation could increase to more than 18TWh by 2008/09. It should be noted that these figures simply represent an estimate of the maximum potential by a given year, rather than the actual level of output expected. Other factors, such as the economic viability of projects, will affect the actual level of capacity built by a given year, and hence the annual output. In addition, there is some uncertainty surrounding the actual level of build rates achievable, and therefore the actual level of capacity achieved by a given year could be higher or lower than that shown in Table 3.4.

Table 3.4 Maximum realisable renewable potential (TWh/year)

	2005/06	2008/09	2012/13	2016/17
Landfill (total)	4.7	8.7	15.8	26.0
Landfill (cheaper sites)	4.7	5.8	5.7	6.3
Onshore wind	4.7	13.4	29.0	51.5
Hydro <1.25MW	0.1	0.2	0.4	0.6
Hydro 1.25-20MW	1.8	3.1	5.4	8.8
Hydro > 20MW	0.4	0.8	0.8	0.8
Sewage gas	0.3	0.7	1.4	2.4
Offshore wind	3.1	18.5	46.2	86.1
Photovoltaics	0.0	0.0	0.1	0.2
Tidal	0.1	0.2	0.5	1.0
Wave	0.1	0.2	0.5	0.9
Gasification of municipal solid waste	0.1	0.5	1.2	2.2
Biomass—stand-alone	1.9	4.5	9.1	15.9

Source: Enviros and Oxera calculations.

Table 3.4 indicates that the majority of the realisable potential for renewable generation in the future is likely to come from four technology types: landfill gas, onshore wind, offshore wind, and dedicated biomass plant.[17] These technologies also appear to be among the cheaper forms of renewable generation, according to Enviros' unit cost estimates shown in Table 3.5. These estimates show the unit costs for additional generation under each technology type at its maximum realisable potential in certain years. The changes in estimated unit costs are a function of two factors: decreasing capital and operating costs over time as a result of learning (as described in Box 3.1); and increasing costs in the case of onshore wind and landfill gas projects as the less expensive sites become fully utilised.[18]

[17] This does not take into account biomass co-firing, which is considered to be outside the scope of this analysis.

[18] For technologies other than onshore wind and landfill gas, a supply curve has not been modelled, and therefore the change in costs only represents the effect of cost reductions due to learning.

Table 3.5 Unit costs of maximum realisable potential (£/MWh)

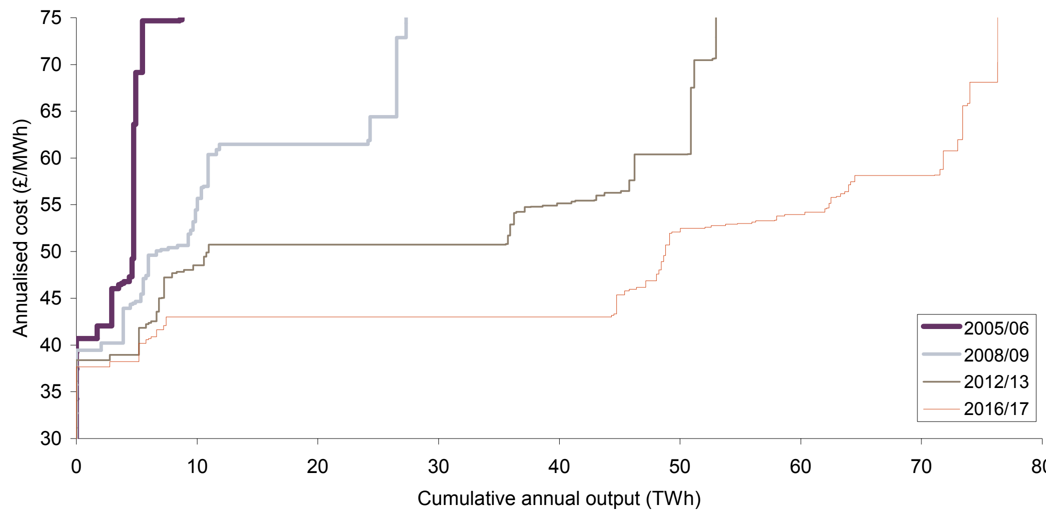
	2005/06	2008/09	2012/13	2016/17
Landfill (total)	44.3	61.9	70.6	58.8
Landfill (cheaper sites)	44.3	43.2	42.4	41.6
Onshore wind	52.5	57.2	56.2	62.1
Hydro <1.25MW	79.8	75.7	70.6	65.8
Hydro 1.25-20MW	63.6	60.4	56.3	52.5
Hydro > 20MW	74.8	72.9	70.5	68.1
Sewage gas	63.0	63.0	63.0	62.9
Offshore wind	74.7	61.5	50.7	43.0
Photovoltaics	555.1	451.2	348.2	275.0
Tidal	107.9	84.4	67.5	65.6
Wave	137.4	107.4	85.9	83.5
Gasification of municipal solid waste	158.6	157.8	155.3	152.4
Biomass—stand-alone	69.1	64.4	60.4	58.1

Note: All prices are quoted in 2004 real terms.
Source: Enviros.

In addition to looking at the resource potentials and costs for individual renewable technologies, it is useful to consider how an aggregate supply curve would look for the total volume of renewable generation likely to be available by a given point in the future. This aggregate supply curve, made up from the supply curves and realisable potentials of each of the individual technologies, will change depending on the year being considered. This is because both the costs of technologies and the potential that can be realised by a given point in time will change. This is illustrated by Figure 3.5, which shows the supply curves for total incremental renewable output in 2005/06, 2008/09, 2012/13 and 2016/17.[19] These incremental supply curves provide a useful measure of the likely level of support required (in the form of the ROC price) in order to achieve a given level of additional renewable generation.

[19] These curves represent the incremental renewable output relative to 2003/04 rather the total renewable output.

Figure 3.5 Base supply curves for total incremental renewable generation (relative to 2003/04 levels)



Source: Enviros and Oxera calculations.

The aggregate supply curve for incremental generation by 2005/06 covers a relatively small volume (especially at lower costs) due to the build-rate constraints assumed for each of the technologies. However, by 2008/09 the realisable volume for each technology will have increased (because of the potential to build at the maximum rate for three additional years), thereby shifting the aggregate supply curve to the right. In addition to this, the effects of learning mean that the costs of building certain technologies are expected to fall over time, shifting the supply curve downwards. The net effect of these two movements is that, over time, the volume of additional renewable generation that could be built at a given unit cost can be expected to increase. The most striking effect on the supply curves is provided by the potential growth in offshore wind generation, which, under an assumption of 1GW per year growth and sharply falling costs, provides for an increasing volume of cheaper renewable generation over time. For example, in 2005/06 there is expected to be just under 6TWh of additional renewable generation below £50/MWh. However, by 2016/17 nearly 50TWh could be available at this price.

4 Commercial viability

The primary objective of the Renewables Obligation is to provide financial support to encourage the efficient development of renewable electricity generation. This support is required because, at present, most forms of renewable generation are more expensive to build and operate than conventional generation. However, over time, technological improvements, changes in the electricity market and greater experience are expected to reduce the costs of certain types of renewable generation to the level where they may no longer need support from the RO in order to be commercially viable.

For a renewable generation technology to be commercially viable, project developers would need to be confident that the revenue streams from a project would be sufficient to recover the full costs of the project. Without support from the RO, the most significant source of revenue for renewable generators will be the sale of electricity via the wholesale electricity market. Further revenue will derive from the exemption of renewable electricity from the CCL. As described in section 2, renewable generators will receive LECs for their output. These certificates can be used to offset the CCL paid by energy consumers and could therefore provide additional revenues of up to £4.3/MWh.

To assess the future commercial viability of renewable generation technologies, it is necessary to explore the drivers on power station revenues and compare the potential range of future revenues for renewable projects against their expected project costs.

4.1 Revenue drivers

In addition to the value of LECs, the main revenue drivers for renewable generation will be factors that are likely to affect wholesale electricity prices. Over the next decade, the most important factors are likely to be:

– fluctuations in market prices for fuels used in electricity generation, primarily natural gas and coal;
– the level of growth in total electricity demand; and
– the value of carbon emission permits under the EU ETS.

Each of these is discussed below.

4.1.1 Input fuel prices

The costs of input fuels are a significant driver of the overall cost of electricity. For example, fuel makes up two-thirds of the overall costs of producing electricity from a new gas-fired power station. In the UK, the two major fuel sources used in the production of electricity are natural gas and coal, accounting for nearly 75% of generation in 2003/04.[20]

Both gas and coal are commodities traded in international markets. As such, prices are dictated mainly by market forces external to developments within the UK. This is particularly the case for coal, which has a much wider international market, and, as a result, prices will be influenced by global supply and demand. Evidence for this has been seen in recent increases in the internationally traded coal price, where economic growth in China has seen higher demand for coal and for bulk shipping used in the transportation of both coal and other commodities.

[20] DTI (2004), 'Energy Trends', Table 5.1, January.

Similarly, due to the interconnection between the UK and Continental Europe, gas prices in the UK are linked to those in the developing western European gas market. Price formation on the Continent could therefore increasingly drive UK gas prices. In particular, the indexation of the gas price to the oil price and the rate of market liberalisation will be significant drivers.

4.1.2 Electricity demand growth

Another driver of the wholesale electricity price is the overall level of demand that the electricity market needs to meet. If the demand to be met by the available generation is growing significantly then prices are likely to remain higher, as more expensive generation is needed to keep the system in balance while new generation comes on line.

The overall demand for generation is therefore dictated by two factors:

– the increase in demand for electricity by consumers—this is typically a function of overall economic growth and will probably rise or fall in line with overall changes in GDP; and
– the change in energy efficiency—any increases in overall final demand can be moderated by higher levels of energy efficiency.

4.1.3 EU Emissions Trading Scheme

The EU ETS began January 1st 2005, establishing an EU-wide cap-and-trade scheme for emissions of greenhouse gases from certain energy-intensive industries. Essentially, the scheme imposes mandatory maximum allowances for CO_2 emissions from the following industries: electricity generation, oil refining, cement, metal and steel production, and glass and ceramics production. Participants within these industries are able to trade allowances among themselves in order to match their actual level of emissions.

The EU ETS is widely expected to lead to an increase in electricity prices, as most forms of electricity generation will be covered by the scheme and therefore require carbon allowances to operate. Under the UK government's national allocation plan (NAP) for the EU ETS, generators will receive free 'grandfathered' allowances proportionate to their expected emissions.[21] However, as allowances can be traded among participants, the emission of CO_2 will represent an opportunity cost to generators, related to the market price for carbon allowances.[22] Allowances for the 2005 compliance period are currently trading at around €6.75/tonne of CO_2 emitted.[23] At these prices and typical CO_2 intensities of approximately 380g/kWh of output for a combined-cycle gas turbine (CCGT) and 850g/kWh for a coal-fired generator, the marginal value of carbon emissions would equate to around £1.75/MWh for a CCGT and £3.96/MWh for a coal-fired station.[24]

It is expected that generators will seek to recover the marginal opportunity cost of carbon allowances within the wholesale electricity market, thereby leading to higher prices.[25] Assuming that generators are able to pass through the full marginal cost of carbon then the EU ETS could be expected to increase wholesale electricity prices by around £2.85/MWh at current carbon prices.[26]

[21] Each EU Member State is required to submit a NAP setting out its allowance volumes and allocation mechanisms for the initial phase of the EU ETS up to December 31st 2007.

[22] Because allowances that are not used to offset the actual emissions could be sold to other users.

[23] This carbon price assessment is based on the values quoted on January 14th 2005 by carbon market analysts, Point Carbon.

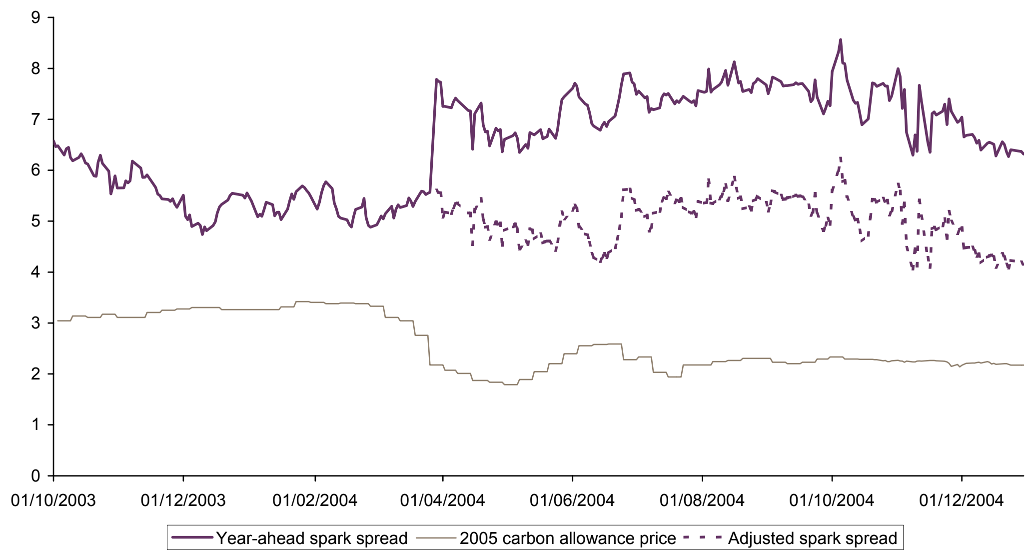
[24] The carbon intensities employed here are consistent with those used in the DTI's updated energy projections of May 2004, with efficiency factors for gas and coal generation of 50% and 35% respectively; a sterling to euro exchange rate of £1:€1.45 is also assumed.

[25] Ilex (2003), 'Implications of the EU ETS for the power sector—A report to DTI, DEFRA and Ofgem', September.

[26] This assumes that the marginal system-wide carbon intensity will be set by coal for 50% of the year and by gas for the remaining 50%.

At this early stage in the EU ETS, there is still some uncertainty about the degree to which the marginal costs of carbon are feeding through to electricity prices, although there does appear to be evidence within the forward markets to suggest that a significant proportion of the expected cost of carbon is being passed through. Figure 4.1 shows the year-ahead spark spreads calculated on data for each of the days from October 2003 to December 2004.[27] The figure shows that there was a sharp increase in the year-ahead spark spread from the end of March 2004, at which point the period covered by the year-ahead contracts changed from April 2004 to March 2005 (where there are few or no impacts from carbon pricing), to April 2005 to March 2006 (ie, after the start of the EU ETS); the implication of this being that the forward markets expected the price of electricity to rise in 2005/06 for reasons other than an increase in gas prices.

Figure 4.1 Forward spark spreads and EU ETS allowance costs (£/MWh)



Source: Argus reports, Heren reports, Point Carbon, and Oxera calculations.

There are a number of reasons why the spark spreads would be different between the two periods—for example, year-on-year changes in the relativities of fuel prices, a significant tightening in the electricity supply/demand balance between periods, as well as general expectations in the market. However, the inclusion of EU ETS allowance costs could also account for the shift. Also shown on Figure 4.1 is the marginal cost of carbon to a typical CCGT generator over time, based on the price of 2005 carbon allowances. Adjusting the spark spread by the estimated cost of carbon removes the step change in the spark spread from late March 2004 onwards, resulting in a pattern of spark spreads for 2005/06 similar to those seen for 2004/05. This indicates that the forward expectations of electricity prices under the EU ETS rose roughly in line with the expected opportunity cost of carbon allowances to gas-fired generators.

4.2 Creation of 'states of the world'

While each of the drivers described above would, in isolation, have greater (fuel prices and EU ETS costs) or lesser (demand growth assumptions) impact on electricity prices, it is useful to consider the broad range of electricity price outcomes that could occur as a result of the combination of scenarios for each driver. To this end, three 'states of the world' have been created for the purposes of this study in order to explore the boundaries of future

[27] The spark spread is defined as the difference in price between the market prices for electricity and natural gas at a given conversion efficiency, and is a useful measure of the net revenues earned by a gas-fired power station.

electricity prices. The intention is to investigate the impact that different potential electricity market environments could have on the commercial viability of renewable generation, rather than to predict what electricity prices will be. Therefore, the ‘states of the world’ represent the combination of scenarios most likely to lead to high and low electricity prices, as well as a set of scenarios reflecting a central electricity price outcome.

Central

In this state of the world, fuel prices start at relatively high current levels and then trend downwards closer to historical levels. The EU ETS allowance price out-turns are at a level similar to that seen in today’s forward markets. In the absence of any further advancement or information on the second compliance period, the current EU ETS price is carried forward to the end of the modelling horizon. The overall demand for electricity, net of any energy efficiency gains, continues at a rate consistent with that seen in recent years, growing annually at 0.7%.

The key variables of this ‘state of the world’ are described in Table A1.1 in appendix 1.

High

The combination of events that are likely to lead to high wholesale electricity prices will require high fuel costs, EU ETS prices and above-average demand growth. In this high ‘state of the world’, Oxera assumes that fuel prices remain high, perhaps owing to high economic growth internationally, with gas prices continuing at their current, historically high, levels into the future, and coal prices falling to around 20% above the long-term expected level (consistent with historical variations about the average). It is also assumed that strong UK economic growth drives demand for electricity to increase annually by 1.7%, boosted by a failure within the economy as a whole to make significant energy efficiency improvements. Furthermore, it is assumed that economic growth is also experienced in Europe, and a combination of increased demand for allowances and a tightening of national caps in response to strong environmental commitments sees the EU ETS allowance prices increase significantly beyond 2008.

The key variables of this ‘state of the world’ are described in Table A1.2.

Low

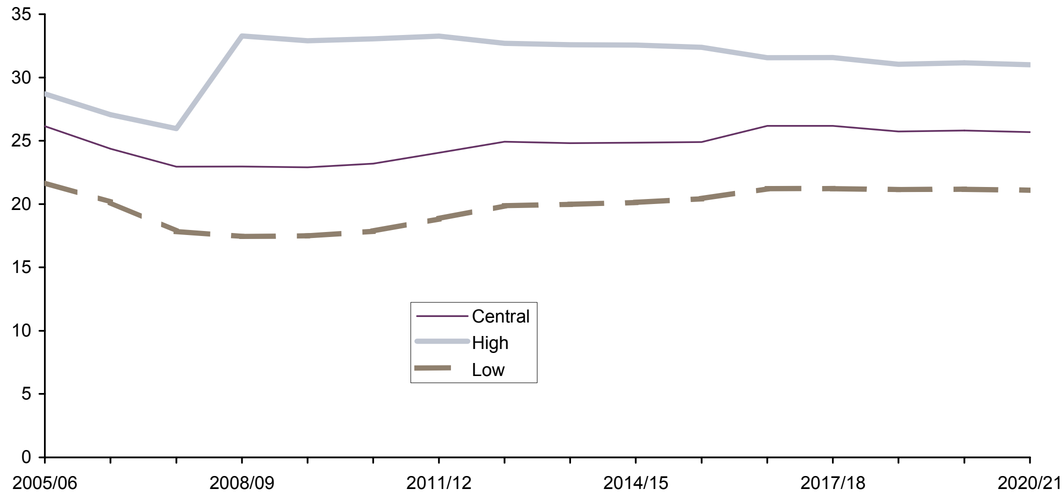
In this state of the world, economic growth slows. International fuel prices retreat much more rapidly from their current highs, and remain at relatively low levels through to 2020. The economic downturn also hits production across Europe, with output levels being significantly lower than expected. This, combined with much less stringent EU ETS caps imposed by Member States, results in a collapse in the EU ETS allowance price beyond 2008. The slowdown in GDP growth is also seen within the UK, and overall demand for electricity is consequently lower than in the other two states of the world.

The key variables of this ‘state of the world’ are described in Table A1.3.

4.2.1 Resulting wholesale electricity streams

The three states of the world were modelled using Oxera’s wholesale electricity market model to evaluate the likely out-turn price for wholesale electricity. The results for the three states of the world are shown in Figure 4.2.

Figure 4.2 Wholesale electricity price scenarios (£/MWh)



Source: Oxera.

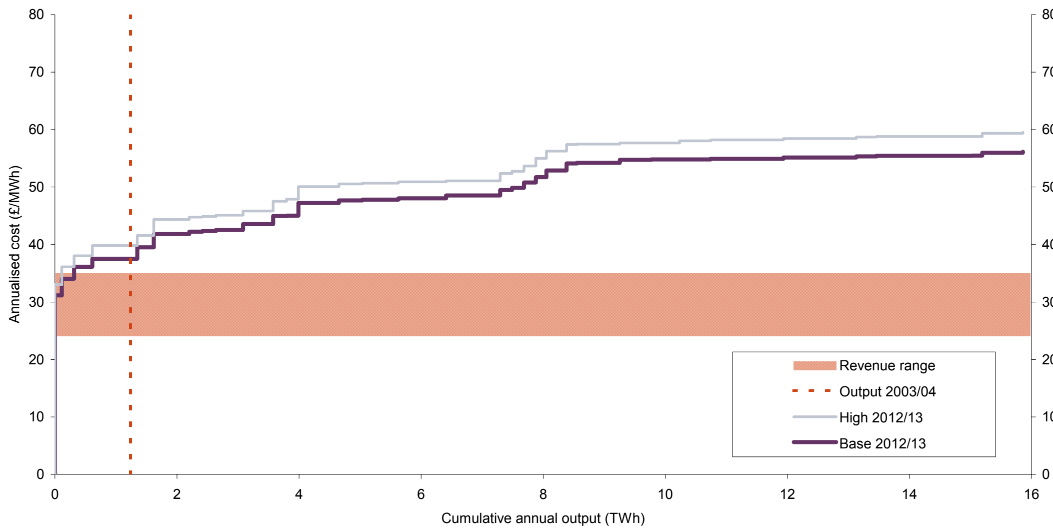
In both the low and central 'states of the world', a combination of falling fuel prices, and stable-to-falling EU ETS allowance prices sees prices drop in the near term, before gradually increasing as a result of rising gas prices lifting the future new-entrant CCGT cost.

In the high 'state of the world', the sharpest increase occurs between the first and second compliance periods of the EU ETS. The high 'state of the world' assumes that the price of allowances could jump to €25/tonne CO_2 in the second compliance period (from the €10/tonne CO_2 assumed up to 2008). This, combined with the higher fuel cost assumptions, means that fossil-fired generation technologies would face significant increases in their cost base and would keep electricity prices well above £30/MWh in the long term.

4.3 Will some technologies not require support from the RO?

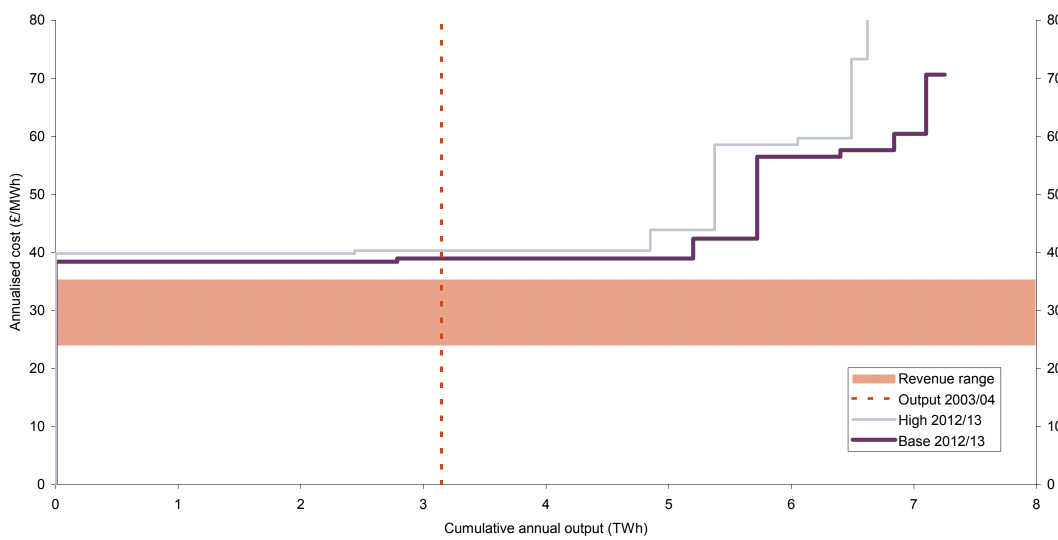
For a renewable generation technology to become commercially viable, it would be necessary for the expected revenues of a project (wholesale electricity sales and LECs) to exceed the total capital and operating costs. Therefore, it is possible to express a threshold for the commercial viability for a particular renewable technology as the point in time when the unit costs of developing additional capacity fall below the expected annuitised value of wholesale electricity prices and LECs over the life of the project. As previous sections of this report have shown, there is significant uncertainty in both renewables costs and future electricity prices. However, in the majority of cases, there appears to be little potential for the market revenues of new renewable generators to exceed their costs. Figures 4.3 and 4.4 illustrate the total of costs of new generation and expected revenue levels (based on the value of LECs and the 'states of the world' assumptions for wholesale electricity prices) in 2012/13, for onshore wind and landfill gas respectively.

Figure 4.3 Onshore wind costs and annuitised electricity prices (2012/13)



Source: Enviros and Oxera.

Figure 4.4 Landfill gas costs and annuitised electricity prices (2012/13)



Source: Enviros and Oxera.

In the case of onshore wind, very little of the supply curve falls within the range of expected market revenues, and, given the current output levels, those projects that do fall within the revenue range are likely to have been developed already. The landfill gas chart also shows that there are unlikely to be any projects in the near future that would be commercially viable without continued support from the RO.

As mentioned previously, whether a technology is likely to become commercially viable will depend on the interaction between wholesale electricity prices and renewable costs. A combination of drivers resulting in high electricity prices, together with the assumptions under the base unit cost scenario, is the situation most likely to lead to certain technologies becoming commercially viable. However, even under these favourable assumptions, none of the renewable generation projects would be commercially viable outside of the RO framework.

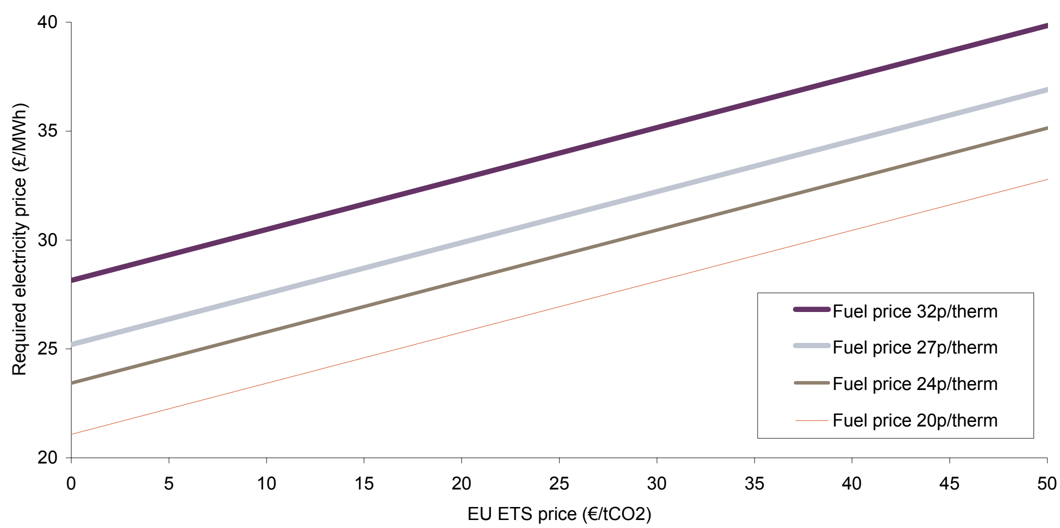
4.3.1 Competition with conventional technologies

Another factor to consider when assessing whether renewable technologies might be viable without support from the RO is whether they would be competitive against the most efficient forms of conventional electricity generation. The reason for this is that electricity generators are expected to invest in the generating technologies most likely to provide them with the greatest return. In all likelihood, this will mean that renewable generation without RO support will have to be competitive with high-efficiency CCGT generation. Development of CCGT generation is subject to slightly different economic drivers than renewable generation, mostly because the total costs for CCGT generators include the costs of input fuels and the effect of the EU ETS.

If it is assumed that new CCGT generators will have to purchase on the open market sufficient EU ETS allowances to cover their emissions then the price of carbon allowances will form part of the cost base against which the decision on whether to build a new CCGT would be made. Higher ETS prices would therefore lead to a higher overall cost for a CCGT project, which would need to be recovered through higher electricity prices. If, on the other hand, new CCGT projects receive a proportion of their output as a free allocation then the ETS price will have less of an impact on the project economics.[28]

Figure 4.5 shows the electricity price level that would be required for new investment in CCGT generation under a range of fuel price and EU ETS price assumptions. This analysis assumes a station has 58% efficiency with project capital costs of £360/kW at a capital cost of 12% and no free allocation of EU ETS allowances.[29] Under these assumptions, an increase in the price of the EU ETS by €10/tCO_2 would result in a £2.3/MWh increase in the cost of CCGT generation.

Figure 4.5 New-entry cost for a CCGT under different fuel and ETS price assumptions



Source: Oxera.

What can be seen from this figure is that, even with extremely high fuel cost and carbon price assumptions, the new-entry costs of CCGT generation is unlikely to exceed £40/MWh,

[28] Under the proposed UK NAP for 2005–07, a pool of allowances is available to be allocated freely to new entrants, including power stations. For compliance periods beyond the start of 2008, the new-entrant allocation rules are unclear at present. In the long term, continued allocation of free EU ETS allowances to new entrants will put pressure on incumbent generators to pass through less than the full opportunity costs of the EU ETS into wholesale prices, which could in turn reduce the impact of the EU ETS on wholesale electricity prices.

[29] These are broadly consistent with established industry values.

whereas more credible assumptions would result in a new-entry price below £30/MWh. As Table 3.5 showed, at this price there is limited volume of renewable generation that would be competitive with a CCGT.

4.4 How will the EU ETS affect the commercial viability of renewable generation?

The introduction of the EU ETS is likely to benefit renewable generators as it is expected to lead to higher electricity prices, without affecting the costs of renewable generation. However, the discussion in previous sections has shown that the impact of the EU ETS on electricity prices is likely to be relatively modest at current carbon allowance prices, being somewhere in the order of £2.85/MWh. Given the estimated costs of renewable technologies, the introduction of the EU ETS is unlikely to mean that RO support could be removed from any renewable generation technologies for at least the next decade.

In the longer term, the introduction of the EU ETS could increase the electricity price required to fund new investment in conventional generation, although this will depend on the way in which carbon allowances are allocated to new entrants. If new entrants have to purchase carbon allowances from the open market, these costs will need to be recovered through higher electricity prices, thereby raising the entry costs of conventional generators and making renewable generation relatively more attractive. However, if new entrants receive free allocations of carbon allowances then the cost of new entry will be independent of carbon prices. The continued free allocation of allowances to new entrants could, in the long term, lead to a lower pass-through of the marginal costs of the EU ETS into long-term electricity prices. At this stage it is unclear what the rules for allocating allowances to new entrants will be after 2008.

Assuming that the full impact of the EU ETS is factored into the new-entry cost assumptions for new conventional generators, the price of carbon allowances would need to be significantly higher than current levels in order for most forms of renewable generation to be competitive with a new CCGT. These carbon price thresholds are shown in Table 4.1 for a range of gas price assumptions.[30] These indicate that carbon prices would have to rise to at least €77/tCO_2 in 2008/09 before any of the renewable technologies (in this case, cheaper landfill sites) became competitive with CCGT generation, even at high gas prices of 27p/therm. All other technologies would require EU ETS prices above €100/tCO_2 in order to be competitive with CCGTs.

30 If less than the full marginal cost of the EU ETS were imposed on new CCGT generators (eg, through the free allocation of allowances), these EU ETS price thresholds would be proportionately higher.

Table 4.1 EU ETS price required to match CCGT costs in 2008/09 (€/tCO_2)

	Unit cost under base assumptions (£/MWh)	ETS price required under high fuel scenario	central fuel scenario	low fuel scenario
Landfill (total)	60.9	153	160	170
Landfill (cheaper sites)	43.2	77	85	95
Onshore wind	57.2	137	144	154
Hydro <1.25MW	75.7	216	223	234
Hydro 1.25–20MW	60.4	150	158	168
Hydro >20MW	72.9	204	211	221
Sewage gas	63.0	161	169	179
Offshore wind	61.5	155	162	173
Biomass—stand-alone	64.4	168	175	185

Source: Oxera.

The indications from this analysis are that, at realistic carbon price assumptions, the EU ETS will not provide sufficient additional support for renewable generators to no longer require support from the RO. Furthermore, the level of carbon prices that would be required to ensure that renewable generation would be competitive with new CCGT generators is significantly higher than any currently credible estimates of future allowance prices.

4.5 Levels of support required for renewable generation

While the analysis presented previously in this section suggests that it is unlikely that any form of renewable generation will become commercially viable within the next decade, not all of them will necessarily continue to require the level of support currently provided by the RO. Overall, the level of support required to encourage continued investment in a renewable generation technology will depend on the expectations of wholesale electricity prices in the future, and on the overall costs of building, maintaining and operating a renewable generator. As previously discussed, there is a range of uncertainty surrounding future electricity prices. Furthermore, the costs of developing each type of renewable generation are likely to change over time as a result of cost reductions due to learning and cost increases as favourable sites are used up. Therefore, the level of support required for each type of renewable generation will vary across electricity price and renewable cost assumptions.

Table 4.2 below shows the range of support that would be required to achieve the maximum realisable potential of 'close to market' technologies, given the range of electricity price and renewable cost assumptions used throughout this analysis.[31] This required level of support can be compared with current ROC prices of around £45/MWh and the RO buyout price for the 2004/05 compliance period, of £31.39/MWh.

[31] The maximum realisable volume in any given year assumes that capacity has been added at the build-rate limit in all previous years, and therefore provides an upper bound on the available capacity and support required. The level of support required to achieve less than the full realisable potential could be less than the figures shown.

Table 4.2 Level of support required for investment in each year (£/MWh)

	2005/06	2008/09	2012/13	2016/17
Landfill (total)	9.6–22.8	25.5–51.9	35.4–57.4	24.4–47.8
Landfill (cheaper sites)	9.6–22.8	6.8–22.0	7.1–19.9	7.3–18.8
Onshore wind	17.7–32.1	21.3–37.3	21.1–35.5	27.8–41.6
Hydro <1.25MW	45.2–56.3	40.2–52.4	35.8–46.5	31.6–41.5
Hydro 1.25–20MW	29.0–40.1	24.8–37.1	21.4–32.2	18.2–28.2
Hydro >20MW	40.2–51.3	37.3–49.6	35.6–46.4	33.8–43.8
Sewage gas	28.4–39.5	27.4–39.7	28.1–38.9	28.7–38.6
Offshore wind	40.1–51.3	25.6–38.4	15.7–26.7	8.7–18.7
Biomass—stand-alone	34.6–45.7	28.6–41.3	25.4–36.3	23.8–33.8

Source: Oxera.

An inspection of Table 4.2 shows that most of these close-to-market technologies are likely to be more or less economic in 2005/06 at current ROC prices (the exceptions being micro hydro and offshore wind under low electricity prices). However, it is also apparent that several of the technologies would remain economic with significantly lower ROC prices, in particular the cheaper landfill gas sites.[32] It is also apparent that the level of support required to encourage continued investment will vary over time as the cost of incremental investment in each technology changes. For example, the level of support required for investment in onshore wind continues to rise as the more favourable sites are exploited, whereas the support required for offshore wind may fall over time as costs reduce.

As described in section 2, ROC prices are determined through the interaction between the output of qualifying renewable generation and the size of the obligation, but the RO does not target or guarantee a particular level of support for renewable generators. Therefore, there is a distinct possibility that certain types of renewable generation may receive more support than is necessary to sustain continued investment. This is particularly likely if there is a limit on the rate at which new projects can be brought on line. Within the scope of the RO review, there are several policy options that could be pursued in order to address any over-support for particular technologies. These are investigated in the following section.

[32] This does not necessarily mean that these projects will be developed, as expectations of future ROC prices will also be an important consideration in the investment decision.

5 Policy options

The intention of the RO is to provide a financial incentive for the development of renewable electricity generation, recognising the fact that most forms of renewable generation would not be commercially viable without some form of support. However, the RO provides the same level of support to all forms of renewable generation, without reference to the likely level of support they may require. Over time as certain technologies become commercially viable, or require less support, there may be scope to alter the eligibility rules under the RO to reflect more closely the level of support needed and to ensure that this support is targeted efficiently. These considerations must be balanced against the risk of sending negative or uncertain messages to developers concerning their ability to invest profitably in renewable generation. The government is acutely aware that investor confidence could be adversely affected by its intervention, and, therefore, it is important to ensure that any changes to the RO do not result in currently profitable technologies becoming unprofitable. Within the remit of the RO review, there are five broad options that are open to the government to consider in relation to RO eligibility of a given technology:

– maintain the status quo—ie, retain the current eligibility criteria as described in the Renewables Order;
– completely remove a technology from eligibility—ie, projects initiated after a certain specified date would not be eligible for RO support;
– phase out eligibility for a given technology—ie, reduce the proportion of the output of the technology that qualifies for ROCs over time;
– shorten the period of eligibility—ie, limit the eligibility of output to a set number of years rather than allow eligibility for the full period of the RO (to 2027);
– segment the RO—ie, limit the proportion of ROCs that can be sourced from different technologies over time (as in the process for co-fired ROCs described in section 2.2).

This section investigates the implications of pursuing each of these options, looking at the reasons why it is important to consider changes to the eligibility rules, and how any changes could affect the market for renewable electricity, costs to consumers and the achievement of the government's renewable energy targets.

5.1 Benefits of revising eligibility for close-to-market technologies

The structure of the RO means that it provides the same level of support to all qualifying renewable technologies, regardless of the actual level of support required to be economically commercial viable. By adjusting the eligibility rules for some of the 'closer to market' technologies, it may be possible to target this support more efficiently or to reduce the cost to consumers of achieving a given level of renewable generation.

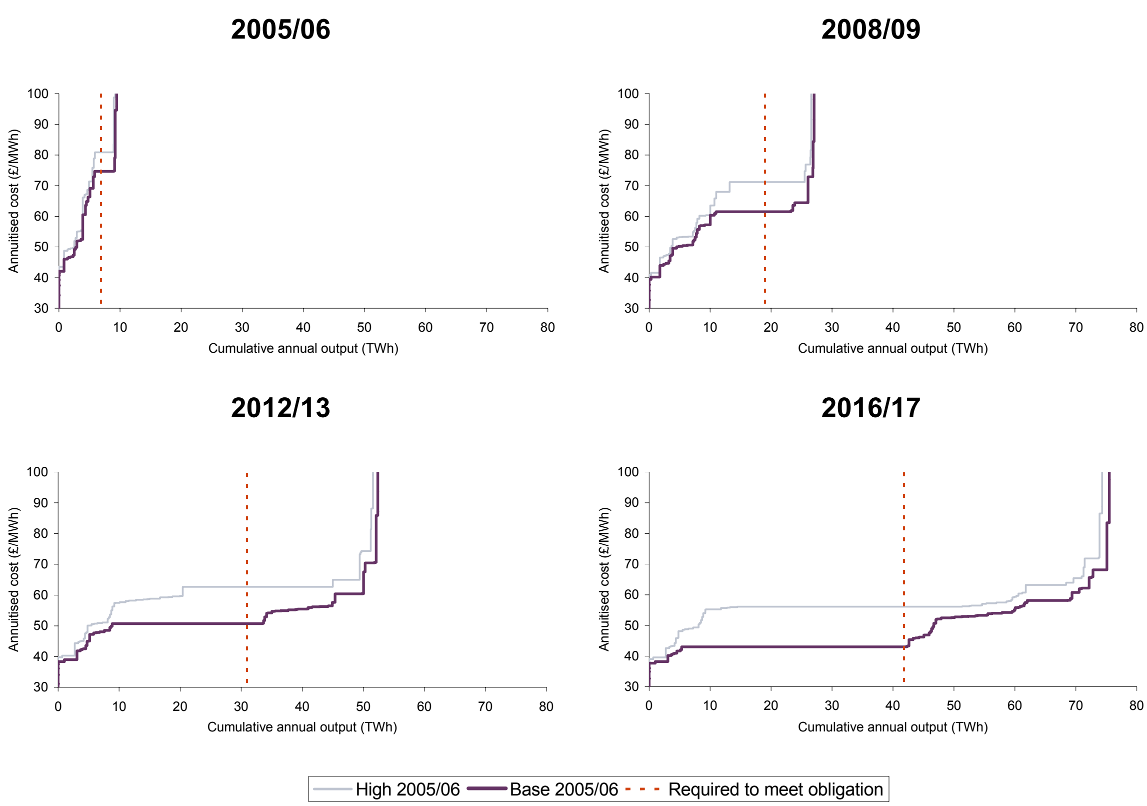
One of the key features of the RO is the ability for suppliers to meet their obligation by paying into the buyout fund, which is recycled back to ROC holders. This has two important consequences:

– the buyout mechanism caps the unit cost of compliance with the RO for a supplier at the buyout price, although the total cost of compliance is still dependent on a supplier's sales volume and the RO target proportions; and
– the value of a ROC will increase as the volume of qualifying generation gets further away from the renewables target volume.

As a result, any moves that decrease the volume of qualifying generation relative to the target volume (such as limiting the eligibility of cheaper technologies) will increase ROC prices without changing suppliers' RO compliance costs and hence the cost passed through to consumers. If this approach were targeted correctly then, although the level of support given to the lower-cost technologies would be reduced, investment in them would remain profitable and continue at the same pace. Meanwhile, higher ROC prices would benefit the technologies remaining within the RO and could result in increased levels of investment in higher-cost other technologies. The net effect could be higher overall levels of renewable generation without any increase in the cost to consumers.

Another possibility is that restricting the eligibility of lower-cost technologies might reduce the need to increase future RO targets in order to meet the government's 20% target by 2020. As mentioned previously and in section 2, the market price of ROCs is strongly related to the ratio of qualifying renewable generation to the size of the RO target. Therefore, in the medium to long term, the volume of qualifying generation could be expected to increase relative to the target size until the ROC price falls to the level required by the marginal renewable technology. However, the increasing size of the RO to 2015/16, combined with changes in the supply curve for renewable generation over time, means that there may not be a significant fall in costs for the marginal renewable generation required to meet the obligation target. This is illustrated in Figure 5.1, which shows the relationship over time between the supply curve for incremental renewable generation and increases in the obligation size.

Figure 5.1 Incremental supply curves and obligation sizes over time



Source: Enviros and Oxera.

By 2016/17, Figure 5.1 shows that the annuitised cost of the marginal technology at the obligation target would be between £43 and £56/MWh, depending on the cost assumption scenario. With the revenues from electricity prices and LECs likely to fall within the range of £24–£34/MWh, the ROC prices would still need to be between £9 and £32/MWh to reach the 15.4% target level. However, the strong relationship between ROC prices and the ratio of qualifying generation to the target level means that ROC prices will not exceed the buyout price of £31.39/MWh (in 2004 real terms) if the obligation target is met. Furthermore, qualifying volumes in excess of the 15.4% target could lead to a significant fall in ROC prices below the level required.[33]

The analysis presented above suggests that, under the current eligibility rules, the RO target would need to continue to increase past 2015/16 in order to facilitate the government's aspiration of 20% renewables by 2020. However, an increase in the size of the RO target will directly increase the volume of renewable generation that suppliers must purchase and hence the cost to consumers. Another approach would be to limit the eligibility of close-to-market technologies, which, as described earlier, would support higher ROC prices and hence increase investment in renewable generation without increasing the cost to consumers. Although this approach alone may not be sufficient to achieve the levels of additional renewable generation necessary to reach the 20% target, it may reduce the size of the RO target increase required.

5.2 Impact of changing eligibility

Any decision regarding revisions to the eligibility of a renewable technology would need to take account of the impact of the revised regime on the cost of achieving the government's targets for renewable energy, which, for the purposes of this discussion, are assumed to be a 20% share of renewables in electricity generation by 2020. The status quo must be seen as the benchmark against which the alternative options are considered.

5.2.1 Status quo

Under the status quo, new investments in all currently eligible technologies would remain part of the RO and continue to produce qualifying generation. However, as the analysis in section 5.1 shows, even the cheapest forms of renewable generation by 2016/17 are still likely to require support from the RO. The interaction between ROC prices and qualifying volumes means that it would therefore be unlikely for renewable generation to significantly exceed 15.4% of supply without an increase in the obligation size after 2015/16.

Renewable generation levels might continue to increase above the target level if some technologies had become fully commercially viable by that stage. However, retaining commercially viable technologies within the RO could lead to a complete collapse in ROC prices, as the market would be flooded with excess qualifying generation. A ROC price collapse could leave higher-cost existing generators with stranded assets. Furthermore, the risk of a ROC price collapse in the future could deter some current potential investors.

5.2.2 Full removal of eligibility

One of the options open to the government under the terms of reference for the RO review is to remove ROC eligibility for new investments in a particular technology. As discussed previously, removing ROC eligibility of a 'commercially viable' technology would result in higher ROC prices for those technologies remaining within the RO, potentially increasing the levels of investment in higher-cost technologies without increasing the cost to consumers from the RO.

Essentially, the removal of a commercially viable technology would mean that increases in renewable generation under the RO would need to come from more expensive technologies. The relationship between ROC prices, qualifying volumes and the RO size means that, for higher-cost projects to be profitable, the level of total qualifying volume will need to be lower than would be the case if the commercially viable technology remained within the RO.

[33] With the demand for ROCs fixed by the target levels, an excess of qualifying generation could see existing generators cutting the price they ask for ROCs in order to sell their full output, leading to a collapse in price. This collapse could be exacerbated by the fact that most renewable generation projects have low marginal costs but high fixed costs, which means that the output of existing renewable generators would be insensitive to a fall in ROC prices. The only way that ROC prices could be maintained in a situation of excess capacity is if some generators choose to restrict their output.

Overall, however, there would be a net increase in the total level of investment in renewable generation, provided that continued investment in the technology removed from the RO remained profitable and competitive with other forms of generation outside of the RO (see section 4.3.1).

The uncertainty surrounding future electricity prices and renewable costs means that there may be considerable doubt as to whether a given technology has become commercially viable. The implication of incorrectly judging a technology to be 'commercially viable' ahead of time would be to stifle further development of a cheap form of renewable generation. By contrast, the impact of incorrectly identifying a viable technology as still requiring support would be less severe. It is therefore likely that a high threshold would be required before technologies could be safely removed.

5.2.3 Phased removal of technologies

Under a phased removal approach, new close-to-market technologies would only receive ROCs for a proportion of their output, thereby reducing the level of support they receive. This approach would have a similar effect to that described under the full removal approach, although the impact would be dampened due to the proportionately lower volume that is removed through the transition. Furthermore, because some RO support is retained, it would be possible to reduce the level of support provided to new projects slowly over time and help to smooth the transition to commercial viability.

5.2.4 Shortening the period of eligibility

Section 4 showed that there is limited scope for any renewable technologies to reach full commercial viability within the next decade, but that there are several technologies that may not require the level of support currently provided by the RO. One option to reduce the level of support provided to these technologies, without fully removing the technology from the RO, would be to shorten the period over which its output qualifies for ROCs. At present, qualifying projects receive ROCs over their entire lifetime, regardless of the project payback period. By restricting the length of time over which close-to-market technologies receive ROCs, it might be possible to reduce the support provided to them while still ensuring that projects remain profitable. More importantly, it is expected that these generators will continue to operate, outside of the RO, once their eligibility has expired, as it is likely that the wholesale electricity prices would be sufficient to cover the ongoing operational costs of most renewable technologies.[34]

Shortening the duration of eligibility for some projects would not directly affect the ROC price in the short term since the volume of qualifying generation would not be reduced. It would, therefore, be unlikely to change the short-term profile of new renewable investment. In the longer term, however, the knowledge that the eligibility of certain projects will end will decrease the level of qualifying volumes expected in the market in the future, and hence increase future ROC price expectations. This expectation of a reduction in the qualifying volumes from existing projects may help to offset the perceived risk of significant ROC price reductions after 2015/16 and lead to continued investment in additional generation.

In addition, this type of adjustment will not inefficiently deter investment in the technology itself. The terms on which qualification for the RO will be determined are straightforward and easy to understand, and the level of support provided over the shortened period should still be sufficient to ensure that build levels are maintained. However, the precise period of eligibility for new projects would be expected to depend on the anticipated level of support required, as discussed in section 4.5.

[34] With the majority of the capital costs having been recovered during the period of ROC eligibility.

5.2.5 Segmentation of the RO

Another approach that could be used to manage the transition of a technology to commercial viability would be segmentation of the RO, placing limits on the volume of ROCs that suppliers can use from particular technologies. This approach is currently being applied to biomass co-firing, with the effect that ROCs from co-firing are typically traded at a discount to other ROCs. Over time, as the proportion of ROCs that can come from co-firing reduces, it is expected that the value of co-fired ROCs will fall, without adversely affecting the price of ROCs for other technologies.

This approach could be extended to other close-to-market technologies, with either a fixed or declining proportion of suppliers' ROCs allowed to come from these sources. The drawback of this approach is that it could limit the contribution from the restricted technologies to the predetermined proportions. As the volume of qualifying generation for the restricted technologies reaches or exceeds the predetermined proportion limits, there could be a sharp drop in the price of ROCs from those technologies, for the same reasons described in section 5.1. Unless the technology had become fully 'commercially viable' by that stage, any further growth in investment beyond the fixed proportion of the target would be unlikely, as this would only depress further the price of 'restricted' ROCs. While this restriction in growth from the close-to-market technologies will benefit other technologies through higher unrestricted ROCs, the net effect could be lower overall renewable volumes.

5.3 Timing of policy change

The timing of any policy change is also important since there remains a high degree of uncertainty over future renewable generation costs, wholesale electricity prices and ROC prices. Furthermore, to maintain investor confidence in the RO, any decision on changing eligibility must have an appropriate lead time before implementation.

Decisions on full or partial removal of eligibility for a particular renewable technology must be based on the expectation that investment in that technology would remain profitable under a range of wholesale electricity price scenarios. Although, at present, there do not appear to be any fully commercially viable technologies, there could be some benefit in pursuing alternative options, which seek to reduce the level of support provided. Decisions on these would have to be based on expected future levels of support required, and, as Table 4.1 shows, there are some important considerations to bear in mind during such a process:

- there is a high degree of uncertainty over the level of support that may be required due to the uncertainty inherent in the underlying generation costs (as indicated in the supply curves in section 3). Thus, for technologies where costs are anticipated to fall over time, the speed with which this reduction occurs will affect the efficiency of reduced support packages;

- support required may actually increase over time as the lowest-cost projects are exhausted and investors are forced to move up the supply curve. Thus, basing decisions on current costs of a given technology could have an adverse effect on the future growth of that particular resource type.

Further work will be required to understand not only the relative merits of different policies, but also the threshold point at which to implement the policies to minimise the downside risk associated with inappropriate removal of eligibility.

5.4 Appropriate technology definition

So far, the discussion has looked at changing RO eligibility for entire categories of renewable generation. However, as section 3 showed, there can be significant differences in the unit costs, and hence the support required for different projects within a technology category. The technologies focused on were onshore wind, where the average wind speed of a site can have a large effect on its output, and landfill gas, where the age of the site and Landfill Regulations will influence the capital investment required.

Within this context, there could be scope for refining the definition of technology types to allow for the differential treatment of diverse types of project within a broad technology category. This is currently the case with hydro generation, where all generators below 20MW capacity are included within the RO, but only new investments are eligible for generators above 20MW. The value of refining the definition of technology categories will depend on the extent to which there is:

– an objective measure by which to distinguish sub-categories of a technology (eg, project size or coverage of other legislation);
– a significant difference in the expected support required by each of the sub-categories;
– a reasonable volume of potential projects in the cheaper sub-category, such that changing their eligibility rules would have a material impact on the achievement of overall renewables objectives.

Based on the analysis presented in the Enviros report and summarised in section 3, there appears to be some potential for separating landfill gas projects on the basis of whether the site is subject to the Landfill Regulations and also possibly on the basis of site size. Enviros' analysis suggests that the unit costs for producing landfill gas from closed sites could be more than £20/MWh higher than active or recently closed sites owing to the requirement under the Landfill Regulations for the latter to be completely capped and have flaring equipment installed. Furthermore, Enviros estimates that the remaining unexploited potential of these cheaper, fully capped sites could be in excess of 2MWh per year by 2016/17.

For onshore wind there appears to be less potential to define separate sub-categories. Enviros' analysis and the supply curve shown in Figure 3.1 suggest that there is no significant step change in onshore wind costs within the range of realisable future projects. This is because the factor most likely to substantially differentiate the unit costs of onshore wind projects is the average wind speed of the site. Enviros expects that the wind speed potential of various sites throughout the UK is likely to come from a regular distribution, rather than there being sharp jumps between the number of sites of a particular wind speed. Locational effects, such as different levels of transmission network use-of-system (TNUoS) charges, may also have an impact on the unit costs of different projects. Differentiation on the basis of location is likely to be problematic, however, and hence has not been considered in detail.

6 Conclusions

This interim report for the DTI's Renewables Obligation Review has focused on analysing the prospects for commercial viability of certain low-cost technologies by assessing the likely cost curves for renewable technologies in conjunction with the main drivers on market revenues (in particular, the EU ETS). The issue of whether certain renewable technologies are likely to become commercially viable, and whether their RO eligibility should be amended, requires careful consideration. The policy implications for the options for dealing with close-to-market renewable generation are discussed qualitatively within this report.

6.1 Renewables costs and revenue drivers

There is still considerable uncertainty surrounding the current and future levels of costs for most renewable generation technologies. The analysis in section 3 of this report, along with the more detailed work carried out by Enviros Consulting, has illustrated a wide variation in the underlying renewables costs in both a static and a dynamic setting.

It is generally expected that the costs of developing particular types of renewable generation technologies will reduce over time as a result of technological and efficiency gains. However, weighed against this will be the fact that, as the more favourable sites for a technology are fully utilised, the costs of incremental investment in that technology will begin to rise. Therefore, the path of future renewable generation costs will depend not only on the rate at which expected capital and operating costs might fall over time, but also on the rate at which the available resource is utilised. Uncertainty surrounding how the level and shape of the supply curve for renewable technologies might change in the future, in addition to the potential variability in revenues from the wholesale electricity market, means that the level of support required for continued investment in a given technology, or indeed any assessment of its commercial viability over time, will be subject to a fair degree of uncertainty.

The main revenue drivers on renewable generation, other than the value of ROCs and LECs under the CCL, is the value of selling output into the wholesale electricity market. A number of interrelated drivers are expected to influence long-term wholesale electricity prices, the most significant of which are levels of demand growth, the cost of fuels used for electricity generation, and the price of carbon allowances under the EU ETS. Variations in the price of fuels in the future are expected to continue to have the greatest influence on wholesale electricity prices. However, the market's unfamiliarity with the EU ETS, combined with a lack of transparency in its long-term structure and the level of allocations made to participants, mean that the long-term cost implications for electricity generators are still unclear. Further uncertainty arises from the fact that there is, as yet, no clear evidence to suggest the degree to which generators' costs under the EU ETS will be passed through to electricity prices, although the assumption of full cost pass-through provides a good upper bound.

At current market prices the EU ETS is expected to increase wholesale electricity prices by around £2.85/MWh, assuming that the full marginal cost is passed through into wholesale prices. However, in terms of looking at the overall revenue drivers on renewable generators, it is necessary to consider the interaction of the EU ETS with the other drivers on wholesale electricity prices. The approach taken has been to look at three broad states of the world, which combine scenarios of the main revenue drivers in order to represent the credible range of long-term electricity prices. It is against these prices that the commercial viability of different types of renewable generation has been analysed.

6.2 Commercial viability of renewable generation

For a renewable generation technology to become commercially viable, it would need to be able to recover its full lifetime costs via the sale of electricity and LECs, without any support from the RO. As it stands, given the renewable generation cost and electricity price assumptions derived in this study, there appears to be limited potential for any renewable technologies to reach commercial viability within the next decade. The technology that currently comes closest to being commercially viable is landfill gas when site capping is required under the Landfill Regulations. However, even under favourable electricity price assumptions, these projects do not appear to be commercially viability without some support from the RO.

The comparison of renewable generation costs and revenue does indicate that, although renewable generation is unlikely to become commercially viable in the foreseeable future, the current level of support provided to some technologies via the RO may be in excess of the levels needed to ensure continued investment. In particular, there appears to be scope to reduce the levels of support provided to onshore wind and some landfill gas projects in the short term, and offshore wind projects in the longer term if development costs continue to fall. The two most practical ways of reducing the levels of support to these technologies are:

– full or partial removal of eligibility from the RO; or
– shortening the duration of time for which a project is eligible for ROCs.[35]

6.3 Implications for renewables policy

In general, there are clear benefits to adjusting the eligibility of different technologies to reflect the level of support they require. In particular, it would result in greater efficiency under the RO as support would be redirected away from close-to-market technologies and towards higher cost projects that would otherwise not be built. The process of reducing eligibility for certain technologies would need to be managed carefully so as to ensure that investment continued in the close-to-market technologies, but the benefit would be potentially higher total levels of renewable generation, without an increase in the cost that the RO imposes on consumers. Alternatively, limiting the eligibility of some technologies might reduce the degree to which the RO target might need to increase after 2015/16 in order to achieve the government's aspiration of 20% of generation from renewable sources by 2020.

Full or partial removal from the RO of future investment in cheaper forms of renewable generation would result in higher ROC prices than would otherwise be the case, as more expensive forms of renewable generation would need to be used to meet the obligation.[36] Meanwhile, the buyout mechanism ensures that the total cost of the RO to suppliers is capped at the buyout price.

The alternative approach of limiting the duration over which certain technologies would remain eligible for ROCs would have a similar effect, reducing the future level of ROCs expected to be available in the market and hence raising future ROC price expectations. The difference with this approach is that there would be no immediate effect on the level of ROCs available to the market in the short term, and therefore this would not affect ROC prices or the level of build for other technologies. However, the expectation of higher ROCs in later years could provide a stimulus for increased investment in the medium term.

A full investigation of the impact of applying these different policy responses will need to take into account how the incentives on investment for all renewable generation technologies

[35] Partial removal of eligibility could be achieved by allocating ROCs equivalent to less than 100% of the output of a particular project

[36] A corollary to this is that the buyout recycling mechanism means that the value of ROCs will increase as the volume of qualifying generation moves further away from the RO target.

would change. To quantify these effects, it is necessary to model the dynamics of the renewable generation market and the role that expectations and risk plays in developers' investment decisions.

Appendix 1 Wholesale electricity market assumptions

Table A1.1 Key input assumptions in the central state of the world

	Coal price (US$/tonne ARA)	Gas price (p/therm NBP)	EU ETS allowance price (€/tonne CO_2)	Annual demand growth (%)
2005	70.6	29.0	8.5	0.7
2006	60.3	26.0	8.5	0.7
2007	49.6	25.0	8.5	0.7
2008	49.3	24.0	8.5	0.7
2009	49.1	23.0	8.5	0.7
2010	48.8	23.0	8.5	0.7
2011	48.6	22.0	8.5	0.7
2012	48.3	21.0	8.5	0.7
2013	48.1	21.0	8.5	0.7
2014	47.9	22.0	8.5	0.7
2015	47.6	23.0	8.5	0.7
2016	47.4	24.0	8.5	0.7
2017	47.1	24.0	8.5	0.7
2018	46.9	24.0	8.5	0.7
2019	46.7	24.0	8.5	0.7
2020	46.4	24.0	8.5	0.7

Note: ARA, Amsterdam-Rotterdam-Antwerp; NBP, National Balancing Point.
Source: Oxera assumptions.

Table A1.2 Key input assumptions in the high state of the world

	Coal price (US$/tonne ARA)	Gas price (p/therm NBP)	EU ETS allowance price (€/tonne CO_2)	Annual demand growth (%)
2005	70.6	32.0	10.0	1.7
2006	70.2	28.0	10.0	1.7
2007	63.0	27.0	10.0	1.7
2008	59.2	27.0	25.0	1.7
2009	58.9	27.0	25.0	1.7
2010	58.6	27.0	25.0	1.7
2011	58.3	27.0	25.0	1.7
2012	58.0	27.0	25.0	1.7
2013	57.7	27.0	25.0	1.7
2014	57.4	27.0	25.0	1.7
2015	57.1	27.0	25.0	1.7
2016	56.9	27.0	25.0	1.7
2017	56.6	27.0	25.0	1.7
2018	56.3	27.0	25.0	1.7
2019	56.0	27.0	25.0	1.7
2020	55.7	27.0	25.0	1.7

Source: Oxera assumptions.

Table A1.3 Key input assumptions in the low state of the world

	Coal price (US$/tonne ARA)	Gas price (p/therm NBP)	EU ETS allowance price (€/tonne CO_2)	Annual demand growth (%)
2005	61.2	25.0	7.0	0.5
2006	50.4	23.0	7.0	0.5
2007	41.4	20.0	7.0	0.5
2008	39.5	20.0	3.5	0.5
2009	39.3	20.0	3.5	0.5
2010	39.1	19.0	3.5	0.5
2011	38.9	18.0	3.5	0.5
2012	38.7	18.0	3.5	0.5
2013	38.5	19.0	3.5	0.5
2014	38.3	20.0	3.5	0.5
2015	38.1	21.0	3.5	0.5
2016	37.9	21.0	3.5	0.5
2017	37.7	21.0	3.5	0.5
2018	37.5	21.0	3.5	0.5
2019	37.3	21.0	3.5	0.5
2020	37.2	21.0	3.5	0.5

Source: Oxera assumptions.

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