Oxera

What is the impact of limiting ROC eligibility for low-cost renewable generation technologies?

Report prepared for Department of Trade and Industry

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Final report

Executive summary

As part of the Department of Trade and Industry's current review of the Renewables Obligation (RO), Oxera investigated the impact of limiting the eligibility to receive Renewable Obligation Certificates (ROCs) for low-cost renewable generation technologies. This study follows on from previous analysis conducted by Oxera and Enviros Consulting for the Renewables Obligation Review, which indicated that certain forms of renewable generation technologies may not require full support from the RO.[1]

The approach used in this study has been to develop a detailed project finance model in order to analyse the economic viability of several hypothetical projects under a variety of market revenue and project finance assumptions. The example projects span a range of potential landfill gas and onshore wind developments, as these were the technologies expected to have the greatest potential to remain viable with reduced levels of ROC support. Four landfill gas projects were analysed, representing variations in the size of installation, while variations in the four onshore wind projects analysed encompass project size, location and the average wind speed expected at the site. The cost and output assumptions for each of these projects were based on the work carried out by Enviros and presented as part of a preliminary consultation in the Renewables Obligation Review.[2]

The main conclusions of this study are as follows.

– The analysis is consistent with earlier findings that some landfill gas and onshore wind projects would remain economically viable with reduced ROC support (either with a time-limited or output-limited approach).

– For landfill gas, the analysis suggests that new large and medium-sized projects would remain viable with reduced ROC support under a broad range of scenarios. However, the findings are less clear for smaller projects (less than 1MW capacity) where relatively optimistic revenue and cost of capital assumptions are required in order for these projects to remain viable with less than full ROC support.

– For onshore wind, the viability of projects with reduced ROC support will depend on site-specific factors, particularly average wind speed. While projects sited in areas with high average wind speeds (8.5m/s or more) would be clearly viable with reduced support, the same conclusion cannot be reached with confidence for sites with lower wind speeds.

– The option of reducing ROC support by limiting the volume of output eligible for ROCs granted has the potential to address some of the site-specific variation in project economics since it would automatically allow projects with lower load factors to receive ROC support for longer. This approach would therefore be particularly relevant if the support for onshore wind is reduced in the future, although the same approach could also be applied to landfill gas.

[1] Oxera (2005), 'What is the Potential for Commercially Viable Renewable Generation Technologies?', January, available at www.oxera.com; and Enviros (2005), 'The Costs of Supplying Renewable Electricity', February.

[2] DTI (2005), '2005–06 Review of the Renewables Obligation: Preliminary Consultation Document', March.

The assumptions used in the project finance model were intentionally conservative, reflecting a desire to avoid drawing conclusions on ROC eligibility that could lead to low-cost investments no longer being pursued. However, there are some assumptions relating to areas where there is considerable uncertainty, such as expected future project revenues and the rates of return required by investors. A wide range of scenarios was employed to represent these factors and reflect this uncertainty. In addition, there are a number of other factors beyond those considered in this report that could impact on the economics of individual projects or have a wider affect on the RO as a whole, and may therefore be relevant to any final policy decisions regarding ROC eligibility. Such considerations could include the typical lifetime of projects, the size of the remaining potential resource, and the number of projects that would potentially be affected by any policy changes.

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1 Introduction

In March 2005, the Department of Trade and Industry (DTI) issued a preliminary consultation as part of its review of the Renewables Obligation (RO).[3] One of the issues addressed in this consultation was whether, in future, there would be potential for certain lower-cost forms of renewable generation to become commercially viable without continued support from the RO. Work undertaken by Enviros Consulting and Oxera, presented alongside the consultation, indicated that, although it is unlikely that any technologies will become commercially viable in the foreseeable future without continued support from the RO, there could be potential to reduce the level of support provided to some projects.[4]

Of the various options that could be used to reduce RO support for low-cost technologies, the preliminary consultation identified the two most attractive options as either those that limit the duration of time over which projects remain eligible for Renewables Obligation Certificates (ROCs), or those that restrict the total lifetime volume of ROCs allocated to these projects. This report investigates the impact of applying these types of limitation to the two forms of renewable generation previously identified as having the greatest potential to remain economic with lower levels of support: landfill gas and onshore wind.

The main objective of the study has been to establish, for a range of example projects within these low-cost technologies, the duration of ROC eligibility and the total volume of ROCs required to meet investment hurdle rates. This information can be used to establish the feasibility of reducing ROC support for some types of renewable generation; however, it is important that decisions affecting ROC eligibility do not result in any perverse incentives on developers or reduce the volume of low-cost generation projects being built. The analysis described in this report has been carried out with this consideration in mind, using conservative assumptions, and, in cases where there is uncertainty, presenting the results of the analysis across a wide range of potential assumptions.

The structure of this report is as follows.

- Section 2 provides a description of the project finance model used in the analysis, and the main revenue and financial assumptions.
- Section 3 presents the analysis of the duration of ROC eligibility required by each of the example projects.
- Section 4 analyses the total lifetime ROC volumes expected to be required.
- Section 5 draws together the conclusions of the study and discusses the wider implications of limiting ROC eligibility on the RO as a whole.

[3] DTI (2005), '2005–06 Review of the Renewables Obligation: Preliminary Consultation Document', March.

[4] Oxera (2005), 'What is the Potential for Commercially Viable Renewable Generation Technologies?', January, available at www.oxera.com; and Enviros (2005), 'The Costs of Supplying Renewable Electricity', February.

2 Financial modelling of renewables projects

To understand the impact of changes in ROC eligibility on investments in low-cost renewable electricity generation projects, it is necessary to understand the factors affecting project profitability, and how potential equity investors and debt providers are likely to view the risks and potential returns associated with these investments. To this end, Oxera developed a purpose-built project finance model to estimate the cash flows to equity and the net present value (NPV) of renewables projects under a range of assumptions about market prices, ROC eligibility and financing options. This model can be used to test for the effect of reducing the length of ROC eligibility on returns to equity in a selection of renewables projects and hence estimate the minimum level of ROC eligibility that would be required for these projects to remain attractive to equity investors.

In addition to the basic financial assessment of projects under consideration, Oxera ran a careful selection of sensitivity and robustness checks to assess the stability and consistency of results in line with the model's adaptation to different technologies. In the course of the project analysis, Oxera's model also attempted to simulate potential financing choices that could be adopted in these projects under different policy and risk scenarios, in order to capture investment criteria and analyse value to investors more accurately.

The approach taken in this analysis has been to assume that investors will seek to finance renewables projects as stand-alone entities through a combination of debt and equity. In practice, however, some renewable generation projects are expected to be developed and financed on the balance sheets of large energy companies. Despite the same project risk, on-balance-sheet developments would benefit from implicit support from the company's other less risky assets, as well as from the application of the company's cost of capital. Since the cost of capital may be lower than the discount rate applied in project finance, the investment hurdle rate could be lower for on-balance-sheet-funded projects. However, other considerations such as the opportunity cost of investments could result in a higher investment hurdle rate for on-balance-sheet-funded projects.

2.1 Revenue and cost structures typical of renewables projects

Renewable generation projects have two main sources of revenue: that derived from selling the electrical output of the project, and the ROCs associated with this output. Over a project's life, both revenue sources are variable and uncertain, with electricity prices tending to follow movements in the price of input fuels and, more recently, the cost of carbon emissions under the EU Emissions Trading Scheme (EU ETS), while the value of ROCs will be related to the total volume of renewable generation relative to the size of the RO. By contrast, the cost structure of a renewables project is relatively stable, with the costs of financing the relatively high upfront capital costs forming the largest part of the cost base.

The need to fund debt repayments and provide returns to equity investors from a variable revenue stream will have an impact on the perceived risks of a renewables project and affect the financial structure, financing costs and required rate of return of the project. One way in which developers can reduce these risks is by entering into a long-term power purchase agreement (PPA) with electricity suppliers, which provides renewable generators with a fixed price for combined electricity and ROCs of the project. The price of a PPA contract is generally lower than the sum of the expected market prices for electricity and ROCs, reflecting the reduced risk for the seller; however, in some cases, a PPA could include some sharing of upside revenues—for example, the value of the buyout fund recycled to ROC holders.

Anecdotal evidence suggests that renewables projects over recent years have been able to negotiate PPA contracts at around £50–£55/MWh, with sharing factors of up to 50% of the recycled buyout value. This compares with average electricity prices during 2004/05 of £25.8/MWh and ROC values of £48.6/MWh.[5]

2.1.1 The impact of ROC eligibility on project revenues

The implications of reducing ROC eligibility for new projects—either through limiting the duration of eligibility or capping the total volume of ROCs allocated to a project—will be to reduce the expected revenues of the project at the point in time when ROCs are no longer received. As well as affecting the total expected revenues of the project, this step change in revenues could have an impact on the project financing structure and leverage that a project could support and hence the overall cost of financing the project.

A further implication of limiting ROC eligibility is that it could place a limit on the duration or volume of PPA contracts into which suppliers are willing to enter. More than half the value of current PPA contracts can be attributed to the value of ROCs. If renewables projects receive ROCs for only a limited period, suppliers may be unwilling to enter into PPAs (even at a lower price) for durations of longer than the expected ROC eligibility. Although it may be possible to negotiate electricity-only PPA contracts for the ROC-ineligible phase of the project, Oxera has assumed that it is more likely that revenue expectations during this period will be based on expected wholesale electricity prices, therefore implying a higher degree of revenue risk.

2.2 Overall financing methodology

The basic analytical framework used in Oxera's project finance model consists of three basic steps:

– analyse different revenue and cost scenarios inclusive of the effects of depreciation, tax, and the ongoing value of core assets;

– optimise the financing structure for each project to proxy the financing policy that investors would adopt to maximise their returns;

– given the optimised financing policy, calculate real, post-tax returns to equity and the project NPV based on a range of risk scenarios (see section 2.3 for the discussion of different risk assumptions).

Oxera's model paid particular attention to the step change in expected revenues for renewables projects that will occur when ROC eligibility for a given project ceases, and the possible implications of this for the duration of any PPA contracts.

The main criterion used within the model for assessing the attractiveness of potential investments is the expected project NPV. The approach taken to estimate the NPV, based on cash flows to levered equity, is one that can correctly account for varying levels of leverage throughout the project life. Corporate finance models based on a constant discount rate are not appropriate in these circumstances, since they are likely to underestimate investors' required rate of return under the high and variable leverage conditions typical of renewables projects.

[5] Sources: average of day-ahead electricity prices quoted by Energy Argus and the price of ROCs sold in the Non-Fossil Purchasing Agency's ROC auctions.

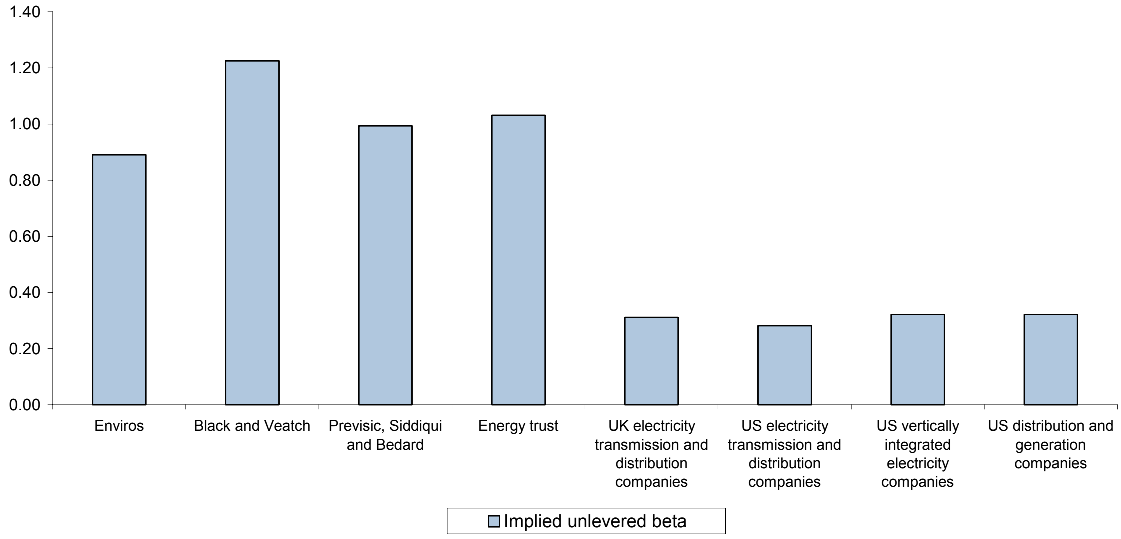
The model has been used to assess the financial viability of a variety of renewables projects under a range of assumptions regarding expected revenues and project risks, and for varying durations of ROC eligibility. In each case, it has been assumed that the projects operate with PPA contracts during the ROC-eligible period, with revenues in the ROC-ineligible period determined by estimates of future wholesale electricity prices. The results and conclusions of the project finance model are based on a central-case estimate of future electricity prices; however, the financial structure employed by the project was stress-tested to ensure that it continues to meet its liquidity and debt sustainability requirements under low electricity price conditions.

Although the methodology used in this analysis is typical of standard valuation models in project finance, the specific treatment of certain assumptions can vary across different analyses. To aid interpretation of the results of this analysis, further details of these assumptions are included in Appendix 1.

2.3 Relationship between risk and return in renewables investments

A fundamental element in determining the economic viability of investments in renewable generation projects is the degree of risk perceived by equity and debt providers, and hence the returns they will require. Based on publicly available information, it is difficult to assess the level of risk currently assumed by renewables investors; moreover, it is likely that risk assessments will vary for specific projects depending on the ownership and contracting structure employed. Therefore, the approach taken in this analysis has been to use a wide range of risk assumptions to assess projects' viability. These risk assumptions, as shown in Figure 2.1 below, are based on a number of published reports on the costs of renewable generation projects, as well as on the risk parameters of several energy sector investments. The regulatory structure of the distribution and transmission sectors means that the energy sector investments used in this comparison represent relatively low-risk assets. The asset betas for these comparator companies have been calculated based on recent market evidence, although regulators in the past have tended to use slightly higher asset beta assumptions (around 0.4 to 0.5) for transmission and distribution companies. Despite the fact that some renewables projects may be low-risk investments, especially those with a PPA contract over the entire project life, the estimated asset betas of the comparator companies are likely to represent a lower bound on the asset betas of renewables projects.

Figure 2.1 Unlevered (asset) beta estimates



Source: Enviros (2005), op. cit,; Black and Veatch (2005), 'Kaua'I Island Utility Cooperative Renewable Energy Technology Assessments', March; Previsic, M. Siddiqui, O. and Bedard, R., Electricity Innovation Institute and Electric Power Research Institute (undated), 'Economic Assessment Methodology for Offshore Wave Power Plants'; and EnergyTrust of Oregon, CH2MHill (2005), 'Phase II Biopower Market Assessment: Sizing and Characterizing the Market for Oregon Biopower Projects', April.

The impact of changing ROC eligibility has been tested using asset beta assumptions of 0.3, 0.9 and 1.5. These parameters represent a very broad spectrum of the possible asset risk assumptions, with a beta of 0.3 representing a highly 'optimistic' view and a beta of 1.5 being highly 'pessimistic'. Although the actual asset betas used by investors will depend on the specific risks of individual projects, and could vary significantly, it is likely that most projects will fall within this range. Appendix 2 provides further information on the relationship between asset risk and required rates of return as well as more details on the comparators used to estimate the range of potential asset betas for renewables investments.

2.3.1 Interpreting results under different risk scenarios

The project NPV estimates for various ROC-eligibility periods have been calculated under a range of assumptions regarding the underlying risk of assets. As indicated above, these differing risk assumptions are reflected by varying levels of unlevered beta and translated into variable discount rates under relevant financing structures, which in turn affect resulting NPV levels. The range of underlying risk assumptions used allows the sensitivity of the model's results to be tested against different potential viewpoints about the expected risk of renewables investments.

When interpreting the results of the financial modelling, for a given level of underlying risk (ie, for each level of the unlevered beta), an NPV of zero implies that investors would be *fully compensated* for their risks and receive sufficient returns to equity to make investment in a project attractive. Similarly, an NPV of greater than zero implies that the investor would earn greater than their required rate of return, while an NPV of less than zero implies that the investors hurdle rate would not be met.

3 Impact of reducing the duration of ROC eligibility

As discussed previously, the impact of reducing the duration of ROC eligibility for new low-cost technologies would be to decrease the expected cash flows of a project towards the end of its economic life. Not only will this reduce the total expected lifetime revenues of the project, but it could also have consequences for the way in which the project is financed. In particular, the loss of ROC eligibility towards the end of the project could:

– reduce the duration of time for which a project can secure a PPA contract;[6]
– decrease the level of debt that the project can support in the ROC-ineligible period;
– increase the revenue risk during the ROC-ineligible period; and consequently
– increase the cost of debt and equity risk.

Each of these factors has been captured in the project finance model and the model has estimated how the expected project NPV will change under different assumptions of ROC eligibility. The objective of this exercise is to determine the minimum number of years of ROC eligibility that would still provide sufficient returns to investors to ensure continued investment. Two of the most significant assumptions in making this assessment relate to the level of returns required by investors and the expected revenues of the project. As described in Appendix 2, the required rate of return for a project is related to an investor's perception of the risk associated with the project. Because there is a great deal of uncertainty regarding investors' perceptions of risk for renewables generation, and this level of risk will vary depending on the specific circumstances of each project, the analysis has estimated project NPVs over a wide range of risk estimates. This range is represented by scenarios of the assumed unlevered asset beta of the project, at levels of 1.5, 0.9 and 0.3.

The range of revenue uncertainty is represented by three scenarios on the price of a PPA contract under which the project might operate:

– a £50/MWh PPA with 50% sharing of the value of any buyout fund recycling;
– a £55/MWh PPA with 50% sharing of the value of any buyout fund recycling;
– a £60/MWh PPA with no sharing of the buyout fund.

Common to each of these scenarios are the assumptions used for wholesale electricity prices during the ROC-ineligible phases of a project, and the size of the ROC buyout fund. These assumptions were based on separate Oxera modelling of the electricity and ROC markets and are outlined in Table 3.1 below.

[6] It is assumed that, at the time of making an investment decision, a renewables developer would be unable to secure an electricity-only PPA contract for the later years of the project.

Table 3.1 Electricity price and ROC recycle value assumptions (£/MWh)

	Low electricity price	Central electricity price	Low recycle value (per ROC)	Central value (per ROC)
2010/11	21.0	33.6	0.47	2.89
2011/12	20.1	31.6	0.28	2.68
2012/13	21.8	31.6	0.59	3.72
2013/14	23.6	31.6	0.32	4.54
2014/15	23.7	31.6	0.48	5.75
2015/16	23.9	31.6	0.39	6.74
2016/17	24.6	31.6	0.38	7.29
2017/18	24.5	31.6	0.26	7.45
2018/19	24.4	31.6	0.13	7.79
2019/20	24.3	31.6	0.59	8.51
2020/21	24.2	31.6	0.09	9.34
2021/22	24.2	31.6	0.22	10.20
2022/23	24.2	31.6	0.50	11.01
2023/24	24.2	31.6	0.74	11.33
2024/25	24.2	31.6	0.99	11.65
2025/26	24.2	31.6	1.24	11.97
2026/27	24.2	31.6	1.49	12.29
2027/28	24.2	31.6	1.74	12.92

Source: Oxera.

Within each of the low-cost generation categories (landfill gas and onshore wind), there are large variations in the cost structures and expected levels of output for potential projects. A key requirement of any changes to the ROC eligibility of new low-cost projects will be to ensure that the changes do not result in efficient projects becoming unattractive to investors. Therefore, the impact of restricting ROC eligibility was tested over a range of example projects, may be considered by investors in 2010. These are:

– a 7MW landfill gas site;
– a 2MW landfill gas site;
– a 1MW landfill gas site
– a 0.75 MW landfill gas site;
– a 30MW wind farm with an average wind speed of 8.5m/s;
– an 80MW wind farm with an average wind speed of 7m/s;
– a 10MW wind farm with an average wind speed of 7m/s;
– an 80MW wind farm with an average wind speed of 6.5m/s.

The technical and costs assumptions used to create these example projects were based on the analysis carried out by Enviros Consulting in its report for the Renewables Obligation Review.[7] On the advice of the DTI, operating cost assumptions for onshore wind have been

[7] Enviros (2005), op. cit.

increased beyond those set out in the Enviros report to reflect changes in the business rate regime for renewables.

3.1 Landfill gas projects

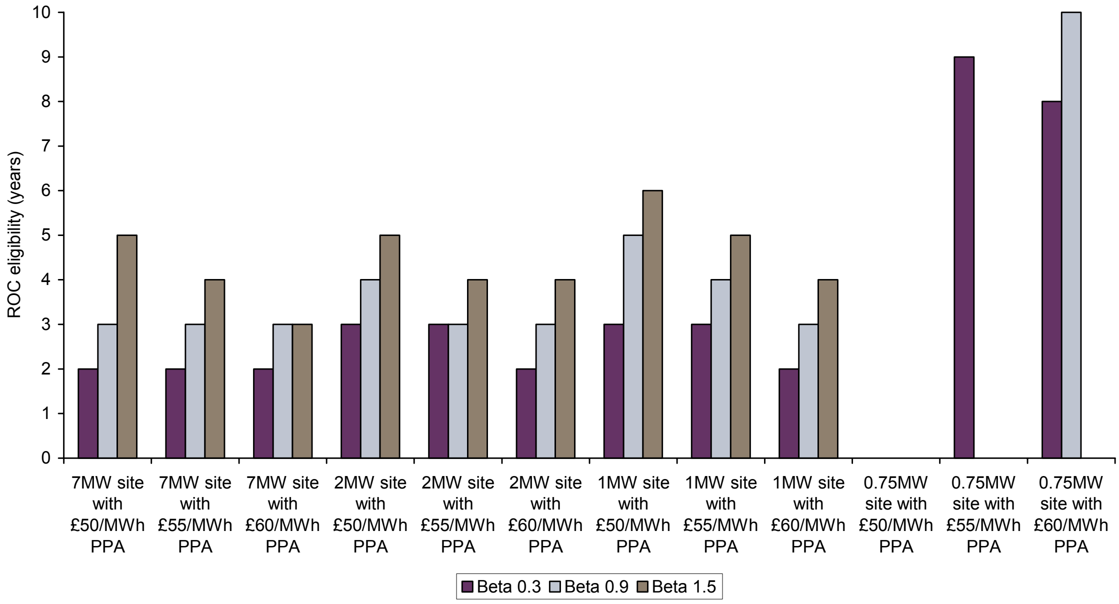
The viability assessments for landfill gas projects were based on operational landfill gas sites, with effective gas collection and flaring systems already installed in conformance with the Landfill Regulations (2002). Future development of landfill gas generation is expected to be based primarily on sites of this type, since older sites are expected to have either been fully utilised or not economically viable.[8]

The main variations between the three types of project relate to the size of the gas resource available, the type of generating engine used, and the relative costs of developing the sites. The smallest site assessed was assumed to be capable of supporting only 0.75MW of generating capacity (comprising three 0.25MW engines), while the larger sites 1MW, 2MW and 7MW were all assumed to use 1MW engines. The Enviros estimates of generating costs result in the costs per unit of installed capacity falling as the size of the site increases. This is a function of utilising the larger-sized engines and spreading the fixed costs of the project over a larger generation volume.

For each of the landfill gas projects, the project finance model was used to establish the minimum number of years of ROC eligibility that would be required under each scenario of contract prices and asset betas for investment in the project to remain attractive. These results are summarised in Figure 3.1. Intuitively, the analysis shows that the number of years of ROC eligibility required decreases as a function of increasing the level of PPA prices and decreasing the level of asset risk assumed. Note that no results are shown for scenarios where a project would not be economically viable even with full ROC support (eg, the 0.75MW landfill site with a £50/MW PPA).

[8] Older sites falling outside of the Landfill Regulations would not necessarily be required to capture the landfill gas emitted. Therefore, to generate electricity from these sites, it would be necessary to retrofit gas capture and storage equipment.

Figure 3.1 Minimum ROC eligibility required by landfill gas sites



Note: Scenarios with no result indicate that the project, even with full ROC eligibility, would not be attractive to investors.
Source: Oxera.

As the figure shows, the projects based on 1MW engines could remain attractive under a wide range of PPA price and asset risk scenarios, even if ROC eligibility were reduced to six years. Under the more optimistic assumptions of a £60/MWh PPA and an asset beta of 0.3, ROC eligibility could be reduced to as little as two years. By contrast, there appears to be less potential to reduce the ROC eligibility for the landfill site based on 0.25MW engines, due to the higher cost per unit of output. The analysis suggests that these projects only begin to become economic with a £55/MWh PPA under low asset risk assumptions, and even with a £60/MWh PPA, a small landfill site might require at least eight years of ROC eligibility to remain attractive to equity investors.

3.2 Onshore wind projects

The range of onshore wind projects analysed encompasses variations in the location and size of the project as well as different levels of average site wind speed. The largest variation in the economics of the projects is provided by the different assumptions on average wind speed since this determines the expected load factor of the project. Higher average wind speeds will result in higher load factors and hence lower costs per unit of output.[9] The location and size of the project will influence its economics by affecting the cost assumptions related to transmission connections and use-of-system charges. The smaller 10MW and 30MW sites are assumed to connect to the electricity system via the local distribution network, while the larger 80MW sites are expected to be connected directly to the national grid. The location of connection for these larger sites is important as transmission charges vary across the network.

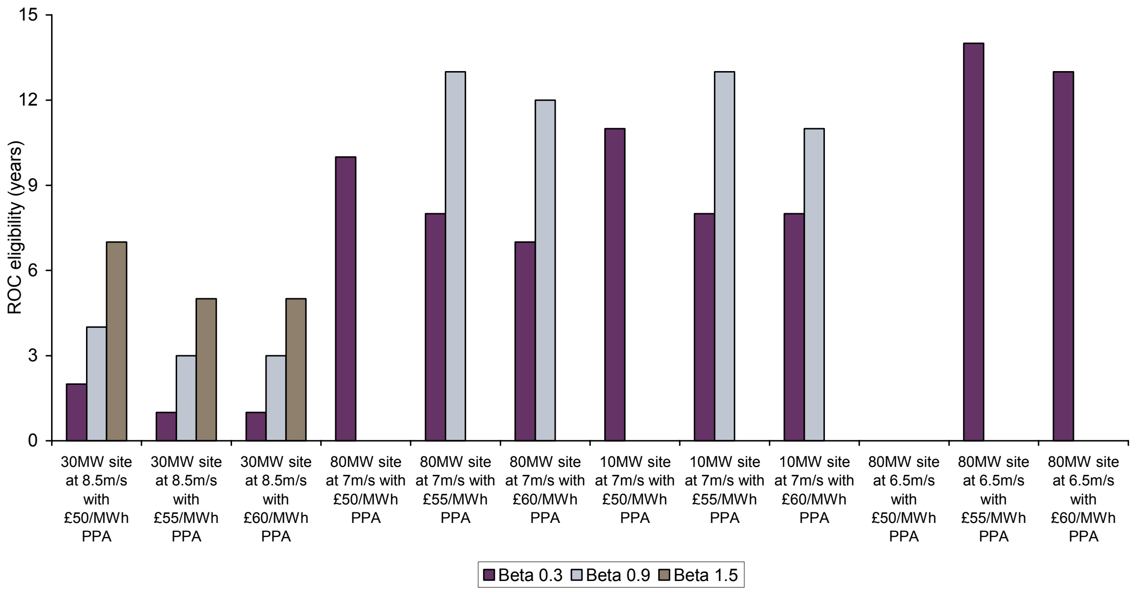
The example projects used in this analysis range from a 30MW wind farm in Scotland with an average wind speed of 8.5m/s, which is expected to be very attractive to investors, through

[9] The majority of wind farm costs are related to the installed capacity of the site rather than the output; therefore, for a given capacity, the cost per unit output will decrease as the load factor increases.

to an 80MW wind farm in north-east England with an average wind speed of 6.5m/s, which may be only marginally economic under the current arrangements.

As Figure 3.2 below shows, the high wind-speed project remains attractive to investors under the full range of PPA prices and asset betas considered. Furthermore, the analysis suggests that these projects would remain viable with ROC eligibility reduced to seven years or less. The conclusions for the moderate and low wind-speed sites are less definitive. There could be some scope for reducing ROC eligibility for moderate wind-speed sites under the higher-price and lower-risk scenarios; however, it appears that the low wind-speed sites may struggle to be economic even with full ROC eligibility.

Figure 3.2 Minimum ROC eligibility required by onshore wind sites



Note: Scenarios with no result indicate that the project, even with full ROC eligibility, would not be attractive to investors.
Source: Oxera.

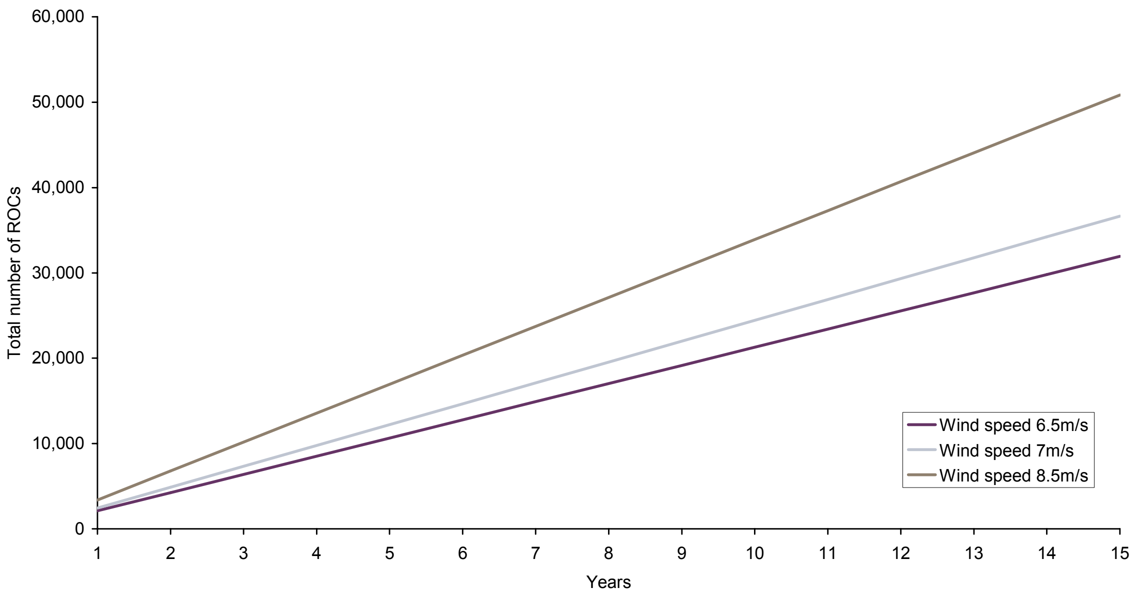
Further details of the cost assumptions and model results for each of the landfill gas and onshore wind projects are provided in Appendix 3.

4 Impact of reducing the ROC volumes

The analysis presented in section 3 shows that some projects would remain attractive to investors with a reduced period of ROC eligibility; however, the duration of eligibility required varies markedly across the range of projects considered. In the case of onshore wind projects in particular, the feasibility of limiting ROC eligibility may depend on the feasibility of applying different levels of restrictions to different types of project. One way of achieving this differentiation could be to apply limits on the total volume of ROCs that a project can receive rather than the duration of time.

Determining a ROC limit based on the installed capacity of a project would allow for projects with lower load factors to receive ROC support for longer than high load-factor projects. For example, limiting ROC eligibility to 30,000 ROCs per MW of installed capacity would equate to approximately nine years of production for an 8.5m/s site, 12 years for a 7m/s site and just over 14 years for a 6.5m/s site.[10] The relationship between duration of ROC eligibility and lifetime ROC volume per MW of installed capacity is shown in Figure 4.1.

Figure 4.1 Lifetime ROC volume per MW of installed capacity

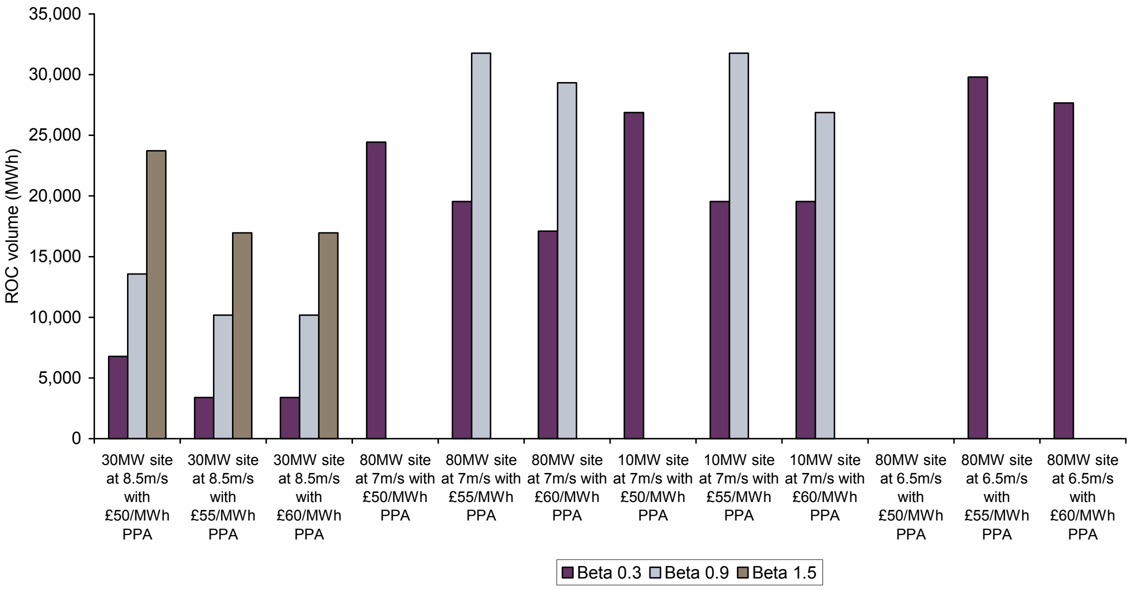


Source: Oxera.

The expected output for different types of onshore wind development can be used to determine the minimum volume of ROCs required for each project to remain attractive to investors. This is presented in Figure 4.2 below, in terms of the lifetime volume of ROCs required for each MW of installed generating capacity. Presented in this way, there is a lower differential in the level of support required for the different projects (compared with limiting the duration of ROC eligibility). However, it is still apparent that, under some scenarios, the medium and low wind-speed projects would not be attractive to investors if ROC volumes were limited to less than the expected lifetime output of the project.

[10] These estimates are based on Enviros' assumed capacity factors of 43%, 31% and 27%, respectively, and an average availability of 90%.

Figure 4.2 Minimum ROC volumes per MW required by onshore wind sites

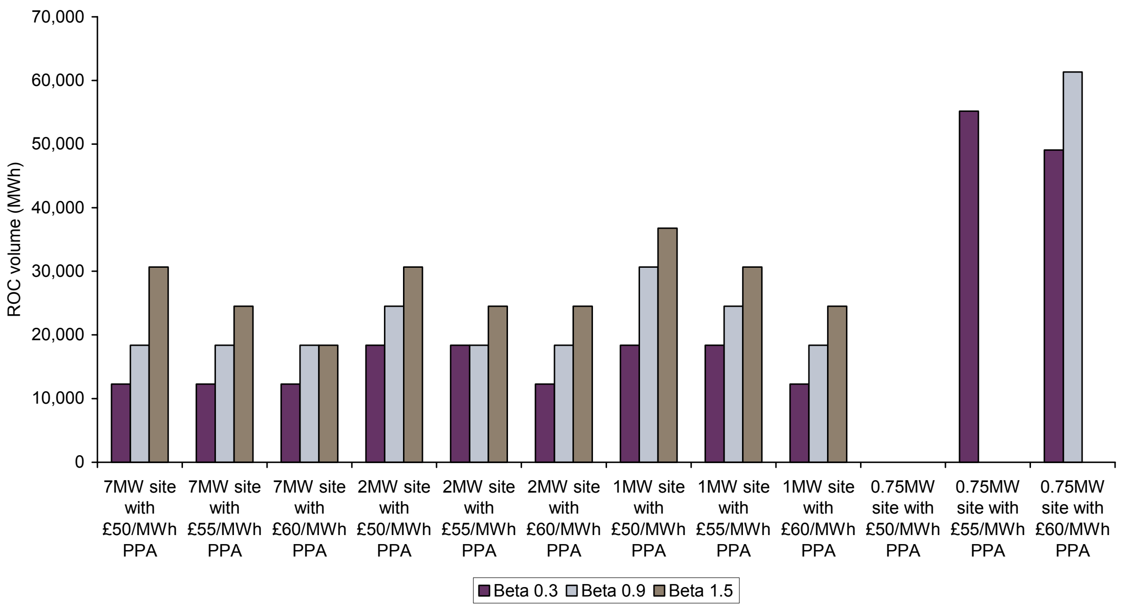


Source: Oxera.

The advantage of limiting the volume of ROC eligibility rather than duration is that it may be possible to set a volumetric limit that is higher than the expected output of a less favourable site, yet still reduce the volume of ROCs allocated to a more favourable site. For example, Figure 4.1 suggests that low and medium wind-speed projects would not be affected by a limit of 37,000 ROCs per MW of capacity, as this would exceed the expected output of these projects over the assumed 15-year lifetime. By contrast, a limit of 37,000 ROCs would be binding for a high wind-speed site, although not to such an extent that it would be likely to deter investment in these projects. Across the lifetime of the project, applying a limit of 37,000 ROCs per MW would reduce the total expected ROCs allocation for a high wind-speed site by around 14,000 ROCs per MW.

Unlike onshore wind projects, landfill gas developments are expected to have similar levels of output per unit of installed capacity. This means that the use of volume limits on ROC eligibility would be less effective at differentiating between projects requiring different durations of ROC support. However, as Figure 4.3 below shows, the main difference in the levels of support required is based on the size of the generating engine assumed to be used in the project, with the small sites using small engines being either uneconomic or requiring a higher volume of ROCs per MW of capacity to remain attractive to investors. One way of addressing this difference could be to limit ROC eligibility, in terms of either duration or volume, only for landfill gas projects above a fixed size.

Figure 4.3 Minimum ROC volumes per MW required by landfill gas sites



Source: Oxera.

5 Conclusions

The results of this analysis indicate that there is potential to reduce the level of ROCs received by some landfill gas and onshore wind projects without making them unattractive to investors. This conclusion is consistent with previous analysis undertaken by Oxera in January 2005 as part of the Renewables Obligation Review, although the conclusions in this report are based on a more detailed representation of the likely financial structure of these projects and hence provide a more robust understanding of the levels of ROC support likely to be required by the different types of project.

The use of a detailed project finance model has also enabled the analysis to investigate the sensitivity of renewables projects to assumptions on expected future revenues and rates of return required by equity investors. The sensitivity of projects to these assumptions is an important consideration as any decision to reduce the level of ROC eligibility would need to be made on the basis that the changes would not result in a reduction in the level of investment in these projects.

5.1 Required levels of ROC eligibility

This report shows that there is clear evidence to suggest that large and medium-sized landfill gas sites could remain economically viable with reduced levels of ROCs, under a wide range of revenue and asset risk assumptions. For smaller landfill sites (less than 1MW installed capacity), there appears to be limited scope to reduce eligibility, as relatively optimistic revenue and asset risk assumptions would be required to meet likely investment thresholds. The conclusions for onshore wind projects follow a similar pattern, with the most attractive projects clearly able to remain viable with reduced ROC eligibility. However, for less favourable projects at moderate and low wind-speed sites, it is less certain that projects would remain economically viable.

This variability in the ROC support required by different projects could be partly addressed by limiting ROCs on the basis of the total volume of ROCs allocated rather than the duration of eligibility. For onshore wind projects, deriving ROC limits on the basis of an allocation per MW of installed capacity would mean that less favourable sites, with lower expected load factors, would remain eligible for ROCs for a longer period of time than the more favourable sites with higher load factors. For landfill gas projects, the costs per MW of capacity are likely to be less variable than for wind projects; however, volume-based ROC limits could still be applied to landfill gas projects.

5.2 Wider implications for the RO

The general principle behind reducing the duration or total level of ROC eligibility for low-cost projects is that this would increase the efficiency of the RO by reallocating some of the 'unnecessary' support provided to these projects to other, more marginal, projects, thereby increasing the total volume of renewable generation being developed. Shortening the duration of eligibility for low-cost projects would not directly affect the ROC price in the medium term, since the volume of qualifying generation would not be reduced. In the longer term, however, the knowledge that the eligibility of certain projects will end will reduce the level of qualifying volumes expected in the market in the future, and hence increase future ROC price expectations, which would in turn increase the support provided to higher cost forms of renewable generation. The extent to which this leads to an overall higher volume of renewable generation will depend on the costs of other renewable technologies and the expected change in total ROC volumes as a result of limiting ROC eligibility.

This study has focused on investigating the sensitivity of several examples renewable projects to changes in ROC eligibility, based on a number of specific assumptions regarding the costs, revenues and investment risks for the various projects. However, the overall impact of any changes to ROC eligibility may also be influenced by other factors such as the typical lifetime of projects, the size of the remaining potential resource, uncertainties surrounding development costs and planning issues, and the number of projects that could be affected by any policy changes. Investigating these factors is beyond the scope of this analysis, although they could be relevant considerations for any final policy decisions on ROC eligibility.

Appendix 1 Financial assumptions

A1.1 Modelling real, post-tax equity returns

The project finance model used in this analysis is set in real terms (ie, with no inflation). All prices, financing costs, and rates of returns are converted to real terms according to the long-term GDP deflator. This implies that all reported rates of return to equity are given in *real* terms and must be inflated prior to any comparison with nominal benchmarks from other studies or analyses, where relevant.

All reported equity returns are post-tax. Furthermore, all NPV calculations incorporate appropriate adjustments to discount rates, to take into consideration varying levels of gearing. In this respect, the employed methodology makes the necessary year-on-year adjustments to the discount rate in each case, according to the changing level of gearing throughout the project life, as explained below. This point is particularly important, since it would not be appropriate to compare directly unlevered and levered equity returns from different sources or equity returns calculated at different levels of leverage since they refer to fundamentally different cash flows.

A1.2 General business assumptions

In the course of this analysis, each investment is considered as a separate, stand-alone project. In contrast to on-balance-sheet projects, a constant level of gearing has not been assumed. On-balance-sheet projects typically benefit from implicit guarantees from a company's other potentially less risky businesses, as well as diversification of risk at the company level. While the required rate of return on such projects should not be assumed to be different, in practice many corporate investors discount all on-balance-sheet project cash flows at the overall company cost of capital.

In line with market practice, Oxera's analysis models net equity cash flows to be repaid to investors as soon as possible through dividends in order to maximise the NPV of the project. The cash flows available for repayments are subject to the preservation of a minimum level of liquidity, compliance with debt covenants, and, therefore, ensuring the required level of protection for creditors. In this context, the model requires a minimum level of cash balances equal to at least 2–3 years of future cumulative interest payments as a liquidity-proof mechanism. This assumption simulates necessary levels of protection for future debt repayments.

In business terms, assumed rates of depreciation reflect the depreciating asset's ongoing expected levels of future revenue generation. The cost of original investment in the productive asset is assumed to be fully depreciated by the end of the project life. Any sale value of the asset is incorporated into the model as a discount on the initial capital expenditure. In practice, depreciation levels might differ from those assumed in the analysis if, for example, straight-line depreciation is used, subject to the asset life. If effective tax benefits were to be front-loaded under such a scenario, returns may be higher.

The initial asset investment is assumed to take place one year prior to the start of business operations, and all calculations of NPV are made for that day. Equity cash flows are assumed to take place at the end of each year, so that the first cash flows from the project reach investors no earlier than two years after the initial investment, as reflected in discounting.[11]

A1.3 Financing structure and returns

Oxera's analysis optimised the financing structure separately for each renewables project and for each combination of ROC eligibility, revenue expectation and risk profile, thereby simulating the variations in financing structure that would be likely to occur as a result of reducing the duration of ROC eligibility. In that sense, the financing decision is endogenised within the model. While, in practice, various additional financial market considerations at the time of the investment might ultimately determine the detailed financing terms for each project, the objective of this exercise is to take into account important considerations of investors that are likely to influence their effective rates of return.

The generic financing structure assumed for each project consists of two financing periods:

– the period covered by any potential PPA in line with ROC eligibility;
– the ROC-ineligible period when output is sold at prevalent market prices.

Separate financial assumptions have been made regarding these two periods to reflect greater risks associated with the period of operation not covered by a PPA contract. Table A1.1 presents the assumption set that was used to develop the final results presented below. Many of these assumptions are subject to a certain degree of uncertainty; however, the estimates utilised are broadly in line with recent practice in project finance and prevalent industry benchmarks, and the results of the analysis remain robust within reasonable variations in these assumptions.

Table A1.1 Key financing assumptions

	Period covered by a PPA	Period not covered by a PPA
Risk-free rate (%)	2.0	2.0
ERP (%)	4.0	4.0
Corporate tax rate (%)	30.0	30.0
GDP deflator (%)	2.0	2.0
Real debt interest rate (%)	3.5	4.5
Minimum EBIT interest coverage (times)	3.5	4.0
Minimum FFO/total debt (%)	30.0	30.0
Minimum FFO interest coverage (times)	3.5	4.5

Notes: ERP, equity risk premium; FFO, funds from operation; EBIT, earnings before interest and taxes.
Source: Oxera.

In line with the relatively smooth revenue assumptions, a mortgage-type payment schedule is assumed within each of the financing periods. However, a bullet-type or partially amortised structure is allowed, if optimal, with the loan in the second period being used to fully refinance the first-period loan. Where relevant and optimal, a single loan financing structure is also assumed. All loans are fully amortised by the end of project life.

[11] The alternative assumption of mid-year dividends would result in higher returns than those used in the model.

A1.4 Optimising the financial structure

The optimisation of the financing structure can be broadly summarised as being governed by the overarching principle of maximising leverage subject to:

– satisfaction of certain benchmark financial ratios (as likely to be required by creditors);
– NPV maximisation, as the ultimate goal of equity investors.

In the majority of cases, this results in the choice of the highest possible leverage that can be supported by cash flows subject to typical financial covenants and debt requirements. Benchmark financial ratios have been constructed, to approximate investment-grade ratings for both loans at current market rates. Specific benchmarks used in the model include the minimum interest coverage, the minimum free FFO to total debt, and the minimum free FFO debt service coverage.

All benchmarks are tested under a central revenue expectation (encompassing the central electricity price assumptions). However, the analysis includes the financial assessment of a low-revenue expectation (based on low electricity price expectations), to test for creditors' risks including liquidity risk. In effect, each financing plan is structured such that it can withstand the low-case scenario across the life of the project. In each case, the amount of leverage is brought down if it cannot be supported under the low-case scenario. Therefore, the model incorporates liquidity and refinancing risk considerations into the financing plan.

Appendix 2 Risk and returns required for renewables projects

The expected rate of return to equity from the investor's perspective can be estimated in several ways, although the ultimate goal of any given methodology is to compensate investors for risk according to the quantification of the risk–return trade-off. The capital asset pricing model (CAPM) is a one-factor model, which predicts a linear relationship between the risk and expected return of any asset. The model is founded on the premise that investors hold well-diversified asset portfolios; thus, the only risk priced is that which cannot be diversified away—the systematic risk. The non-diversifiable risk that remains is measured relative to the portfolio of all marketable securities, commonly proxied by a broad stock market index, such as the FTSE All-share index. The marginal contribution of a stock to the market portfolio is measured by beta—the sensitivity of the stock's returns to changes in the returns of the market portfolio.

Within the CAPM framework, the cost of equity is measured as the sum of the risk-free rate and the product of the ERP and the risk parameter, beta, as shown in the equation below:

$$r_e = r_f + \beta \times \text{ERP} \qquad \text{Equation A2.1}$$

where:

- r_e is the cost of equity—the rate of return expected by equity investors;
- r_f is the risk-free rate; this is proxied by the yield on index-linked government gilts;
- ERP is the additional return required by investors for holding equities as opposed to risk-free assets;
- β is the equity beta, which measures the sensitivity of asset returns to returns on the market portfolio.

A2.1 Estimating the cost of equity for renewable generation projects

Estimating the cost of equity raises a number of issues: key among these are the measurement concerns surrounding the ERP and the beta. While these issues are always present, irrespective of the asset for which the estimate is being derived, estimating the required rate of return on equity for renewable generation projects poses an additional problem owing to the lack of exchange trading data for similar projects, as no publicly quoted pure-play comparators are available.

However, although the beta component of the cost of equity can only be directly calculated for exchange-listed firms, for unquoted companies and individual projects such as renewable generation projects, beta estimates for listed companies that have broadly similar operational structures and risk profiles might provide an insight into the true beta value. If sufficient care is taken in the choice of such comparators, the derived beta estimate should provide a reasonable proxy.

As the proportion of debt in total financing rises (leverage increases), the variability of equity returns, and hence equity risk, increases proportionally to the increase in leverage. Therefore, while the asset beta reflects the underlying business risk irrespective of gearing (or leverage), the equity beta used for calculating required returns to investors incorporates the effects of both business risk and leverage.

A2.2 The impact of leverage on the cost of debt

Another way in which changes in gearing affect the overall cost of capital is through the debt premium. The debt premium will reflect the probability and costs of bankruptcy. As gearing increases and the amount of equity falls, the probability of default rises. Increases in gearing will therefore tend to affect the credit rating assigned to debt, which will feed through to higher costs of debt finance.

As gearing increases, financial indicators, such as interest cover, will tend to deteriorate. Most debt includes covenants that require the company's behaviour and financial indicators to meet certain guidelines, to protect the debt providers' investment. Increases in gearing that lead to, or increase the probability of, breaches of such covenants will also have a direct impact on credit ratings and the cost of debt.

A2.3 Beta estimates for comparators

To derive appropriate equity beta values to use in the estimation of the cost of equity for the renewable generation projects, equity beta estimates were calculated for a number of comparator companies using published market data. These estimates were then transformed into asset betas (reflecting the underlying core risks irrespective of the financing structure) using gearing levels for the comparator companies. Under the assumption that the group of comparators have a similar risk profile to the projects under consideration, their asset beta is taken to be a reasonable proxy for the asset beta of renewable generation projects.

Table A2.1 presents average asset beta estimates for a number of comparator groups.

Table A2.1 Average asset betas for UK and US comparators

Comparators	3-year daily asset beta	5-year daily asset beta	3-year monthly beta	5-year monthly beta
UK electricity transmission and distribution companies	0.31	0.29	0.19	0.20
US electricity transmission and distribution companies	0.28	0.19	0.16	0.02
US vertically integrated electricity companies	0.32	0.26	0.39	0.26
US distribution and generation companies	0.32	0.21	0.42	0.13

Note: Average estimates are derived by taking simple arithmetic averages of asset betas for each individual company within the comparator sample. Asset betas are estimated using the Miller approach.
UK electricity transmission and distribution companies: National Grid Company, Viridian, Scottish & Southern and ScottishPower;
US electricity transmission and distribution companies: First energy, Northeast Utilities, Consolidated Edison and Ameren;
US vertically integrated electricity companies: AES, Allegheny, Constellation, DTE, FPL, Idacorp, PPL, Puget;
US distribution and generation companies: Progress Energy, TXU and Xcel.
Sources: Datastream and Oxera calculations.

A2.4 Asset betas implied by third-party estimates of the cost of equity for renewable generation projects

An alternative method for deriving a proxy for the value of the beta for renewable generation projects is to calculate the value of the beta implied by previous work on the cost of equity of renewable generation projects.

Table A2.2 outlines third-party estimates of the cost of equity for various projects and the likely value of the asset beta required to derive those estimates, given the gearing assumptions used in deriving them.

Table A2.2 Asset beta values implied by third-party estimates of the cost of equity for renewable generation projects

	Estimate of the cost of equity (%)	Gearing (%)	Implied asset beta range
Enviros (2005)	18	75	0.81–0.97
Black and Veatch (2005)	16	60	1.10–1.35
Previsic, Siddiqui and Bedard	17	70	0.90–1.09
EnergyTrust (2005)	12	50	0.88–1.19

Source: Oxera analysis of the figures presented in Enviros (2005), op. cit.; Black and Veatch (2005), 'Kaua'I Island Utility Cooperative Renewable Energy Technology Assessments', March; Previsic, M. Siddiqui, O. and Bedard, R., Electricity Innovation Institute and Electric Power Research Institute (undated), 'Economic Assessment Methodology for Offshore Wave Power Plants'; and EnergyTrust of Oregon, CH2MHill (2005), 'Phase II Biopower Market Assessment: Sizing and Characterizing the Market for Oregon Biopower Projects', April.

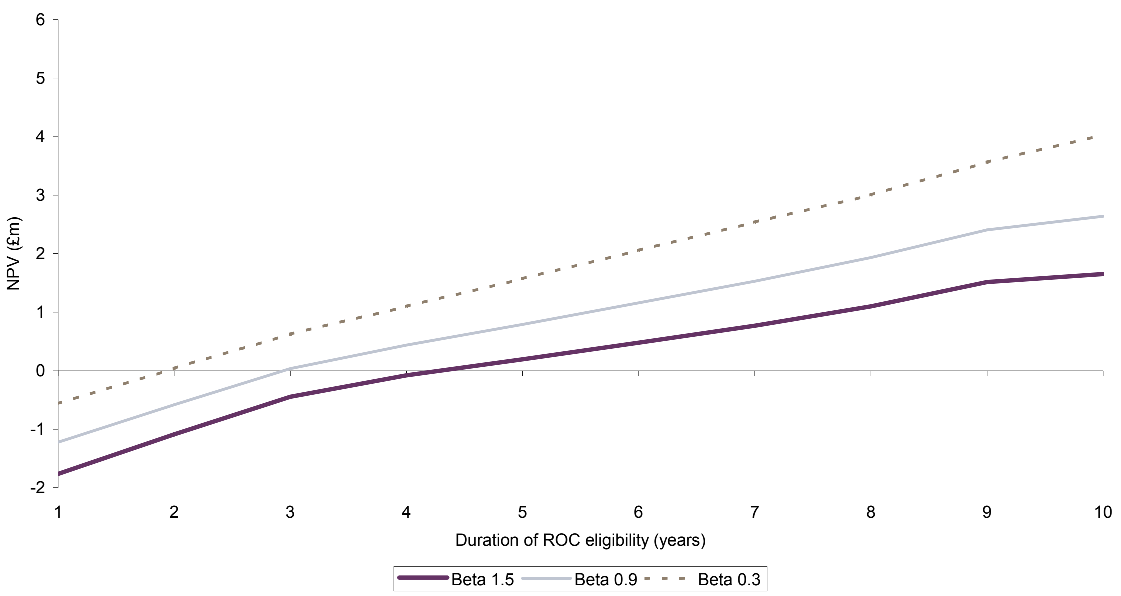
Appendix 3 Detailed modelling results

A3.1 7MW landfill gas site

The assessment for landfill gas projects was based on a large-sized operational site with effective gas collection and flaring systems required as part of the Landfill Regulations (2002). This type of site is referred to as Type 3b in the Enviros report on the costs of renewables, and represents one of the lower-cost options for landfill gas development.[12] The site consists of seven 1MW generating engines and is assumed to be connected to the electricity system via the local distribution network. Other key assumptions with regard to this project are:

– an economic life of ten years;
– capital costs of £6.45m;
– annual operating costs of £0.712m;
– an expected annual output of 42.9GWh.

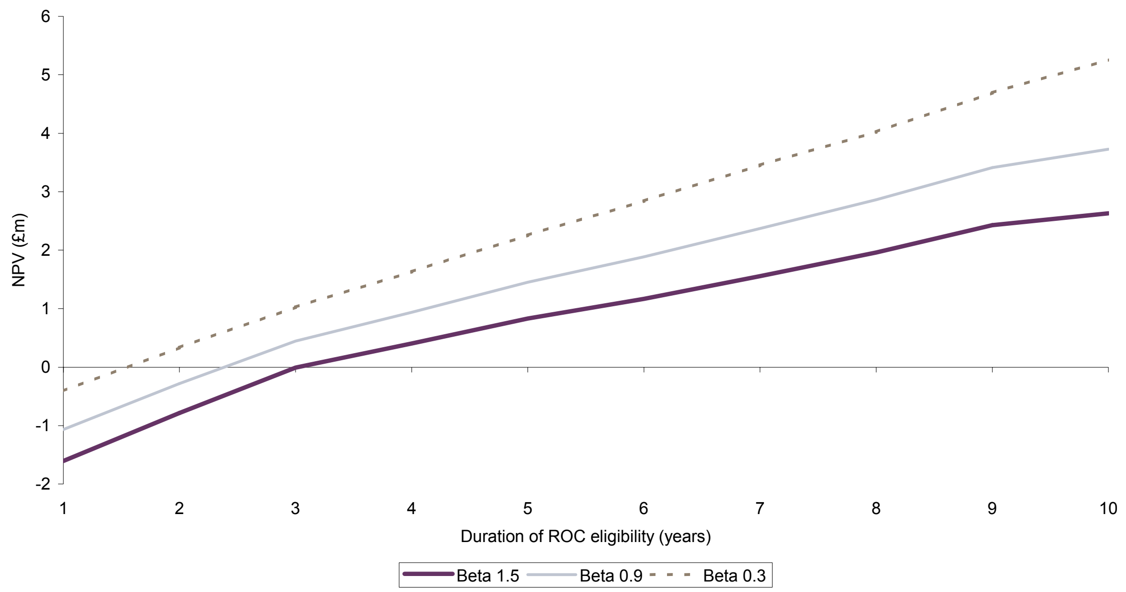
Figure A3.1 NPV for a 7MW landfill gas project with £50/MWh PPA



Source: Oxera.

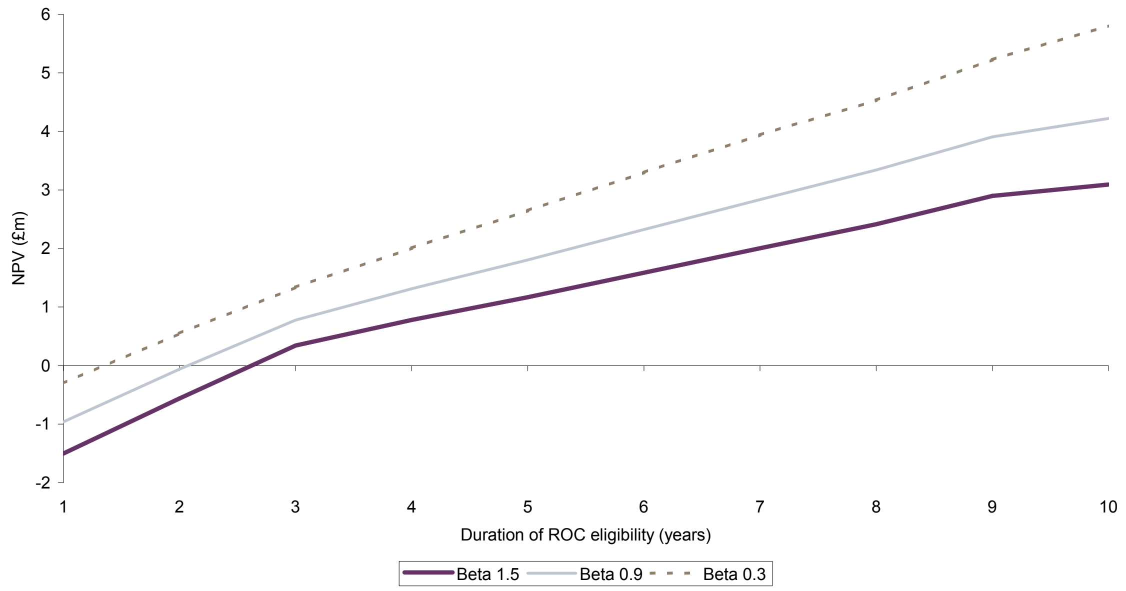
[12] Enviros (2005), op. cit.

Figure A3.2 NPV for a 7MW landfill gas project with £55/MWh PPA



Source: Oxera.

Figure A3.3 NPV for a 7MW landfill gas project with £60/MWh PPA



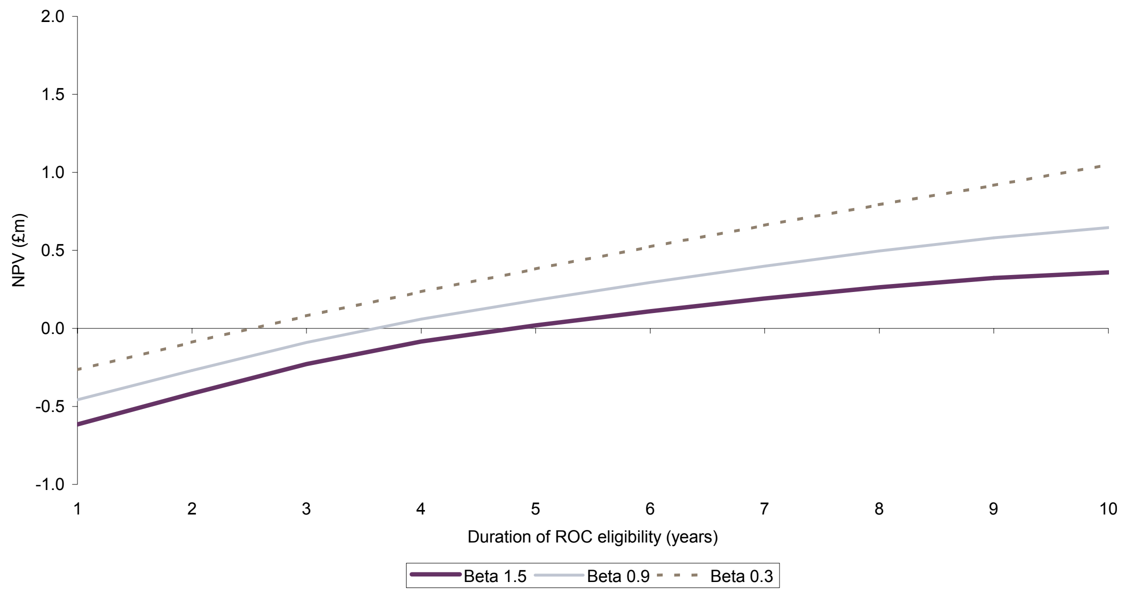
Source: Oxera.

A3.2 2MW landfill gas site

The assumptions underlying this project are similar to the large landfill gas project, with the main difference being a lower expected volume of gas available from the site. This results in a lower generating capacity of 2MW (based on two 1MW engines) and the following financial assumptions:

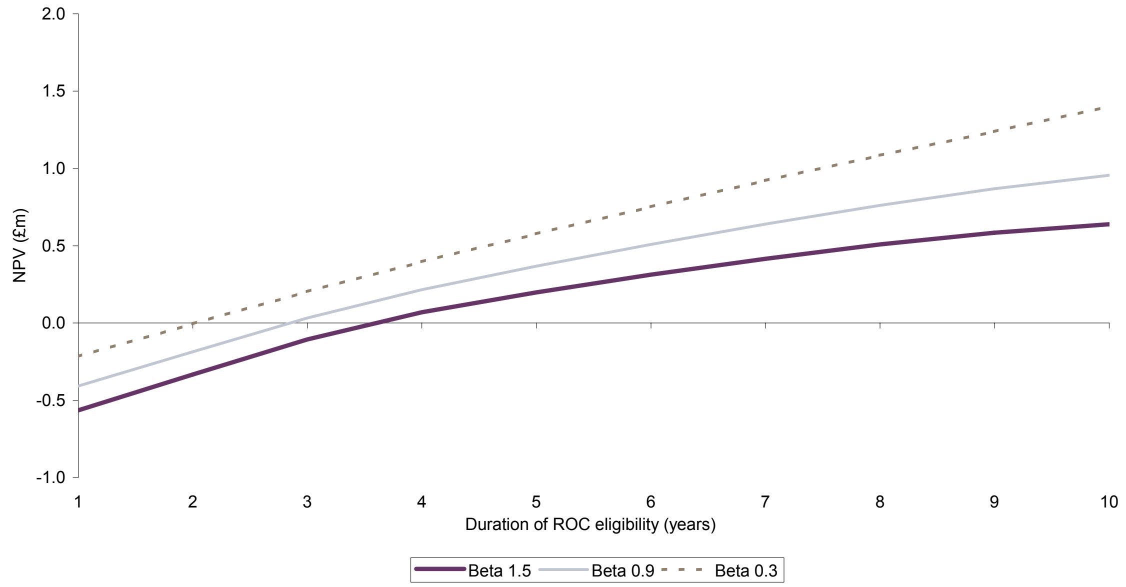
– an economic life of ten years;
– capital costs of £1.98m;
– annual operating costs of £0.2m;
– an expected annual output of 12.3GWh.

Figure A3.4 NPV for a 2MW landfill gas project with £50/MWh PPA



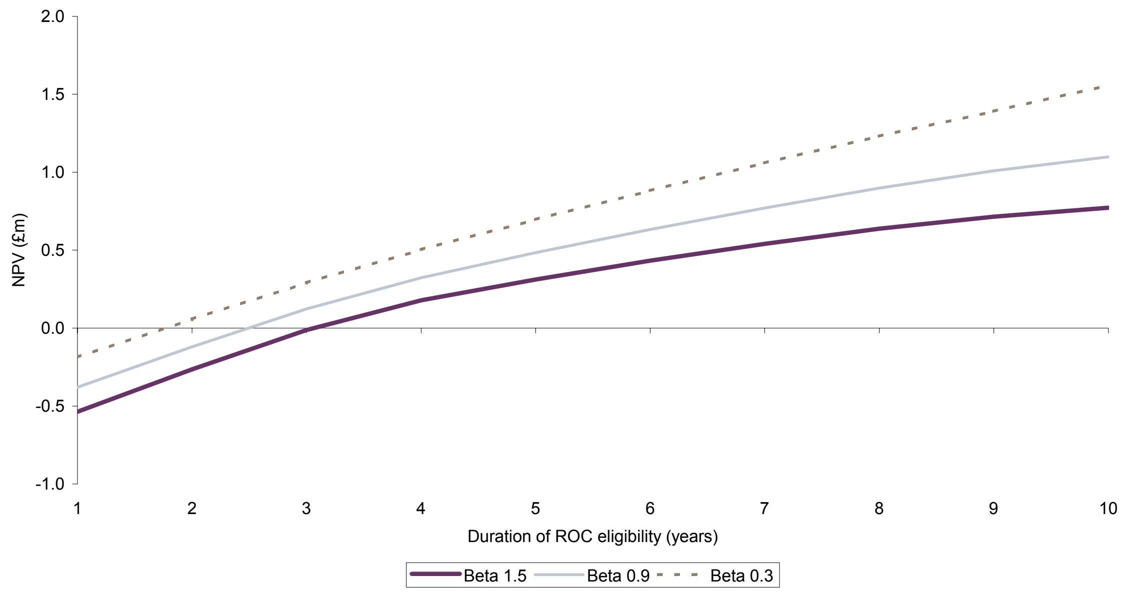
Source: Oxera.

Figure A3.5 NPV for a 2MW landfill gas project with £55/MWh PPA



Source: Oxera.

Figure A3.6 NPV for a 2MW landfill gas project with £60/MWh PPA



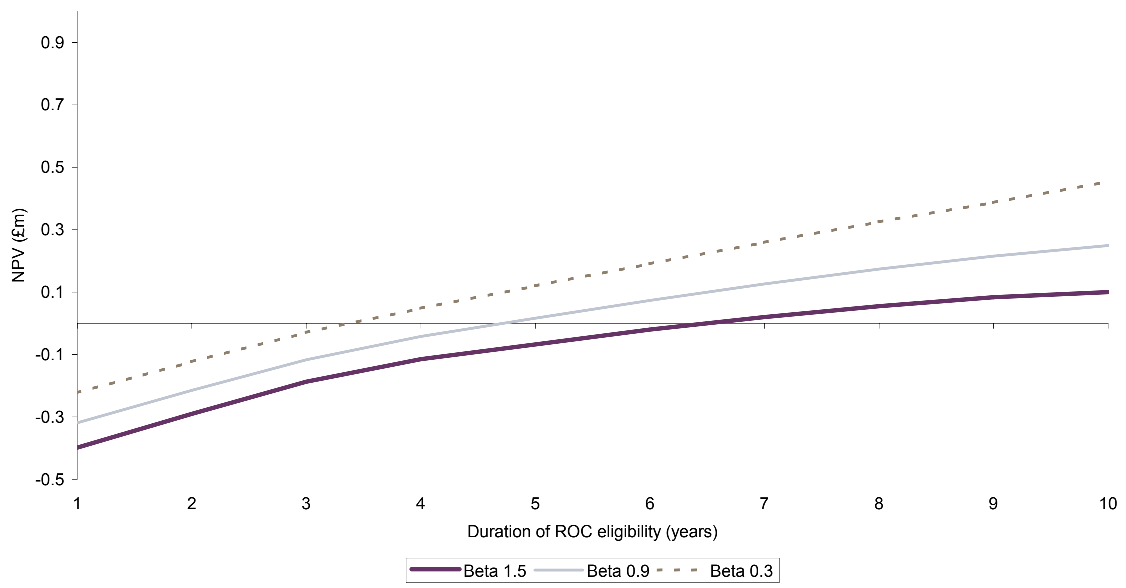
Source: Oxera.

A3.3 1MW landfill gas site

This project also assumes the use of a single 1MW engine and therefore has a similar cost per unit as the project described above. The main difference between the two projects is that the project design and planning costs, which are related to the size of the project, will be spread over a smaller capacity. The financial assumptions used for this project are:

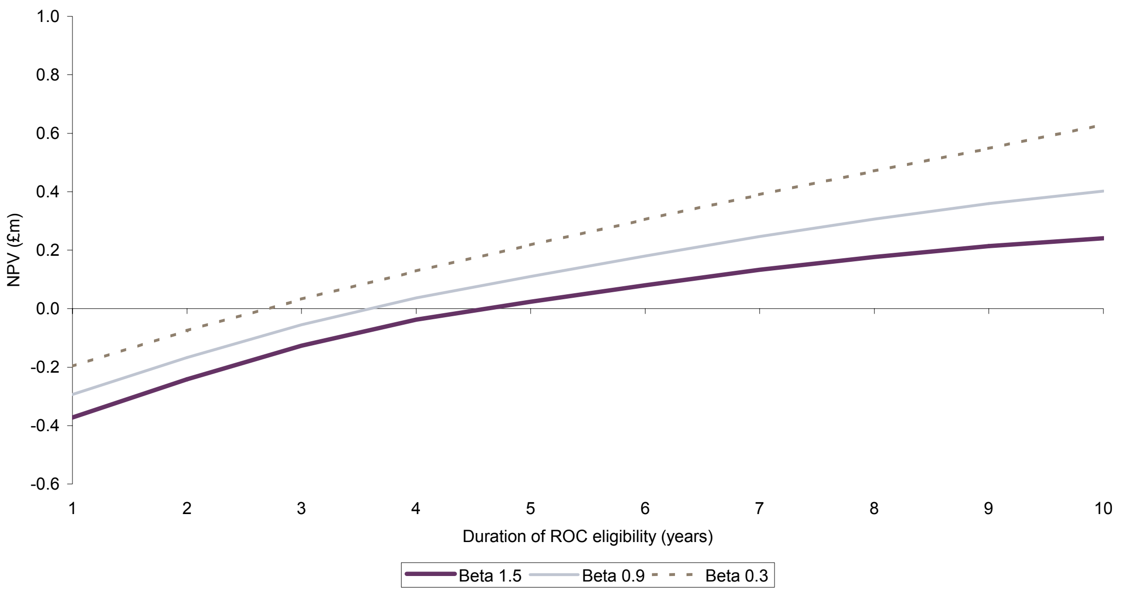
– an economic life of ten years;
– capital costs of £1.08m;
– annual operating costs of £0.102m;
– an expected annual output of 6.1GWh.

Figure A3.7 NPV for a 1MW landfill gas project with £50/MWh PPA



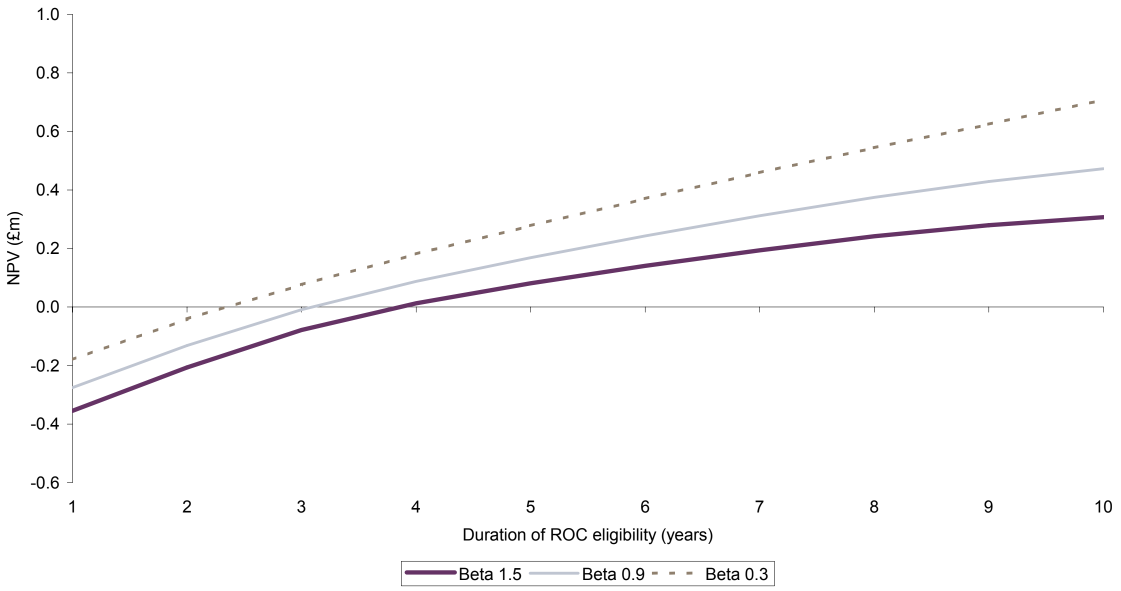
Source: Oxera.

Figure A3.8 NPV for a 1MW landfill gas project with £55/MWh PPA



Source: Oxera.

Figure A3.9 NPV for a 1MW landfill gas project with £60/MWh PPA



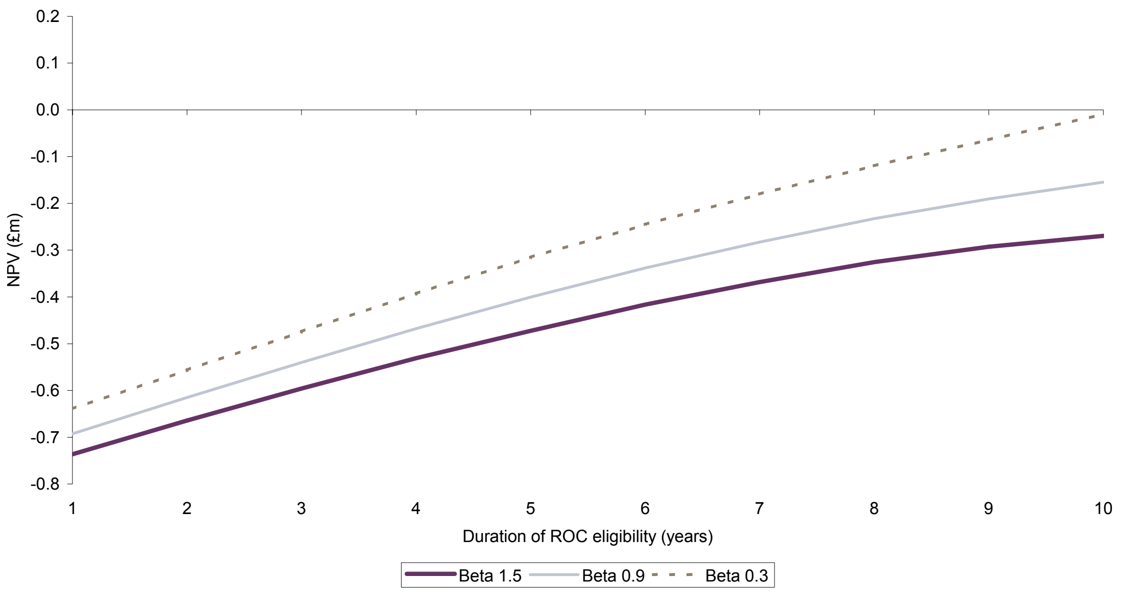
Source: Oxera.

A3.4 0.75MW landfill gas site

The small landfill gas project differs from the two previous landfill projects in that it assumes that the level of gas from the site would be insufficient to support a 1MW engine. Instead, three 0.25MW engines have been used in this project, resulting in a higher cost per unit of capacity. The key financial assumptions of the project are:

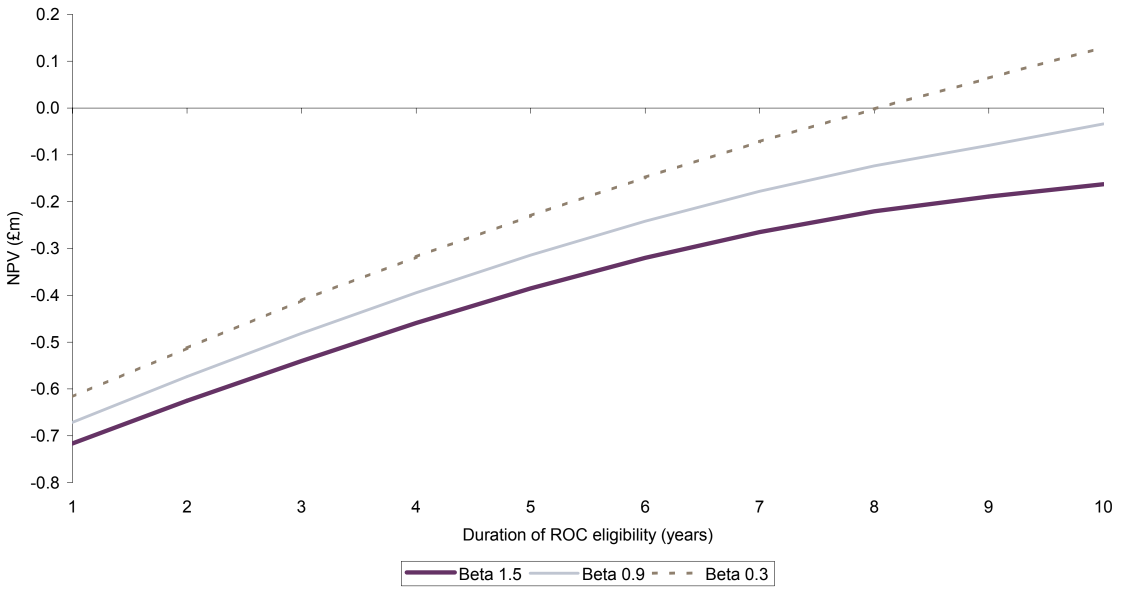
– an economic life of ten years;
– capital costs of £1.1m;
– annual operating costs of £0.1m;
– an expected annual output of 4.6GWh.

Figure A3.10 NPV for a 0.75MW landfill gas project with £50/MWh PPA



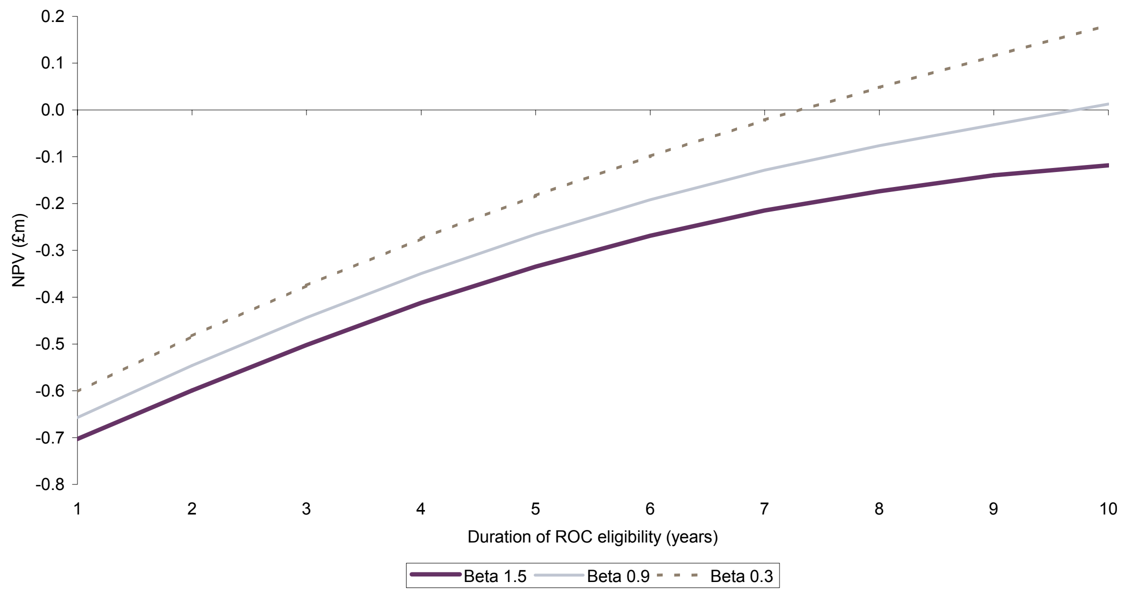
Source: Oxera.

Figure A3.11 NPV for a 0.75MW landfill gas project with £55/MWh PPA



Source: Oxera.

Figure A3.12 NPV for a 0.75MW landfill gas project with £60/MWh PPA



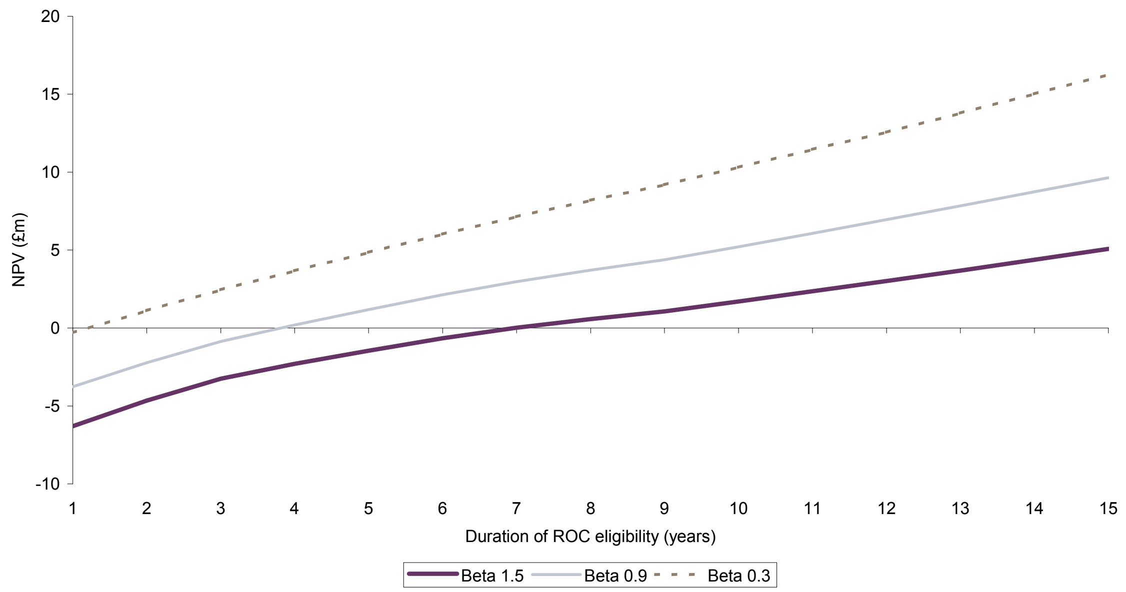
Source: Oxera.

A3.5 30MW onshore wind site with high wind speed

The project represents an onshore wind development expected to be highly profitable under the current RO structure. It is based on a 30MW project sited in Scotland with an average wind speed of 8.5m/s. The key assumptions of the project are:

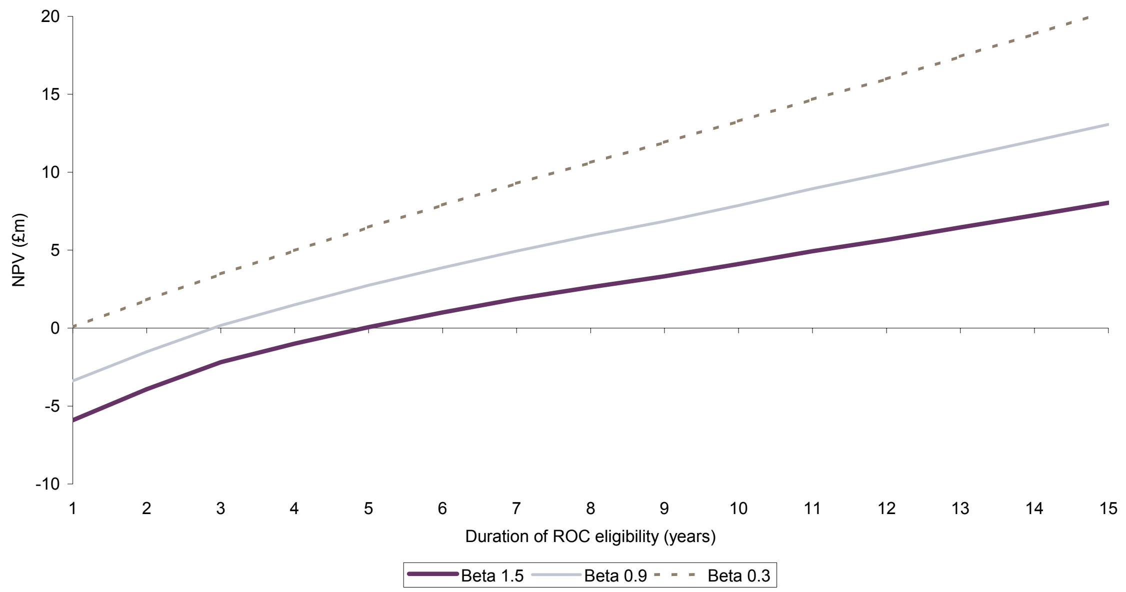
– an economic life of 15 years;
– capital costs of £22.6m;
– annual operating costs of £1.220m;
– an annual output of between 91.3GWh and 112.7GWh.

Figure A3.13 NPV for a 30MW onshore wind site at 8.5m/s with £50/MWh PPA



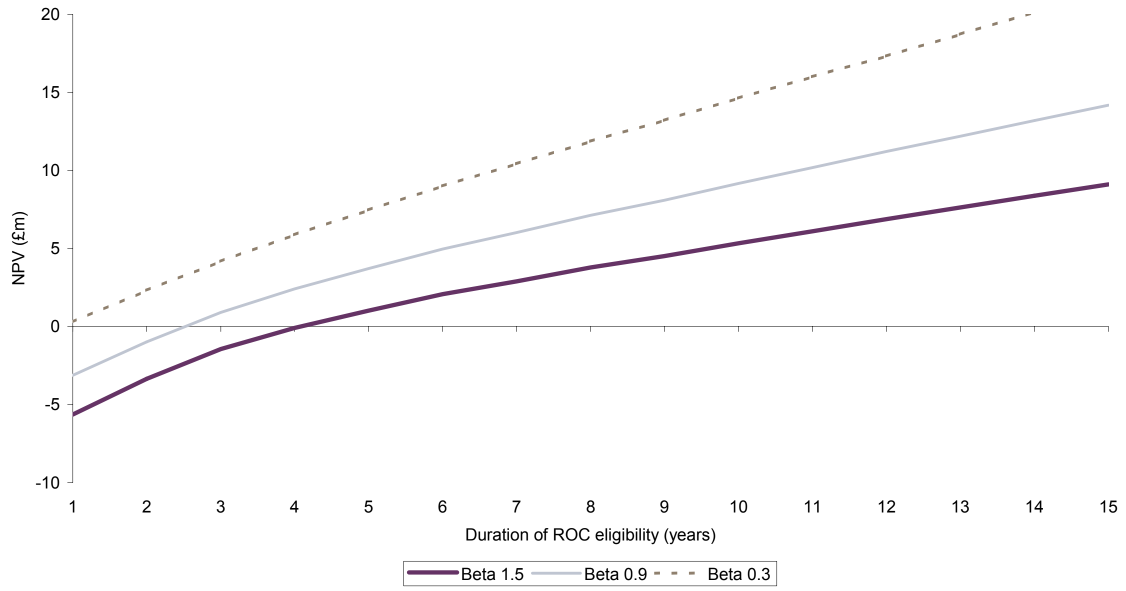
Source: Oxera.

Figure A3.14 NPV for a 30MW onshore wind site at 8.5m/s with £55/MWh PPA



Source: Oxera.

Figure A3.15 NPV for a 30MW onshore wind site at 8.5m/s with £60/MWh PPA



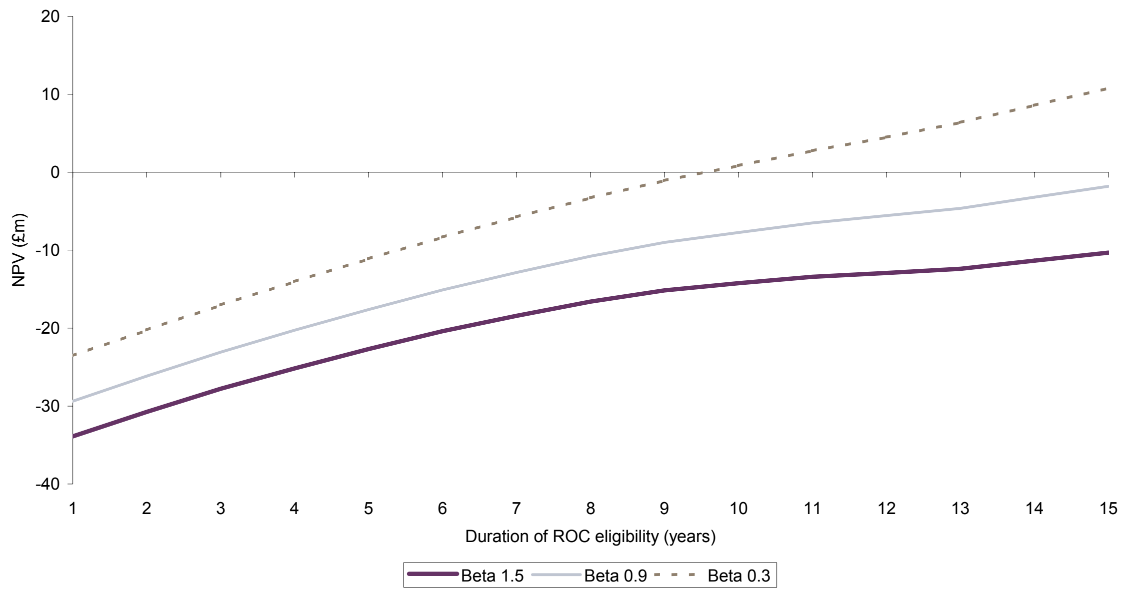
Source: Oxera.

A3.6 80MW onshore wind site with moderate wind speed

This project represents a potential onshore wind development expected to be marginally profitable by 2010. It is based on an 80MW project sited in the east of England with an average wind speed of 7m/s. The key assumptions of the project are:

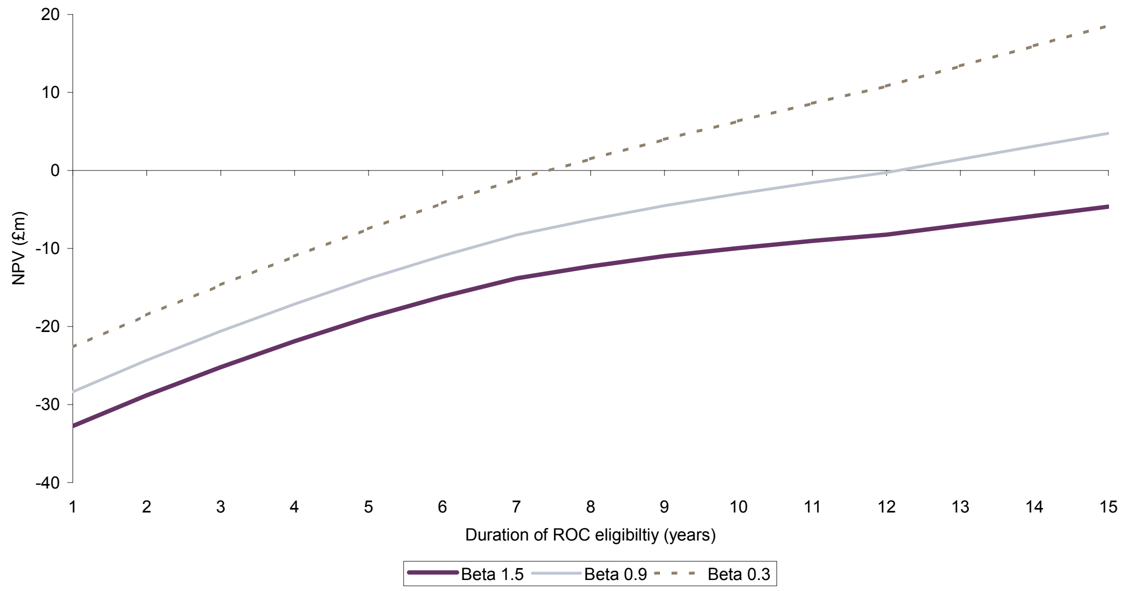
– an economic life of 15 years;
– capital costs of £60.79m;
– annual operating costs of £3.226m;
– an annual output of between 175.4GWh and 216.7GWh.

Figure A3.16 NPV for an 80MW onshore wind site at 7m/s with £50/MWh PPA



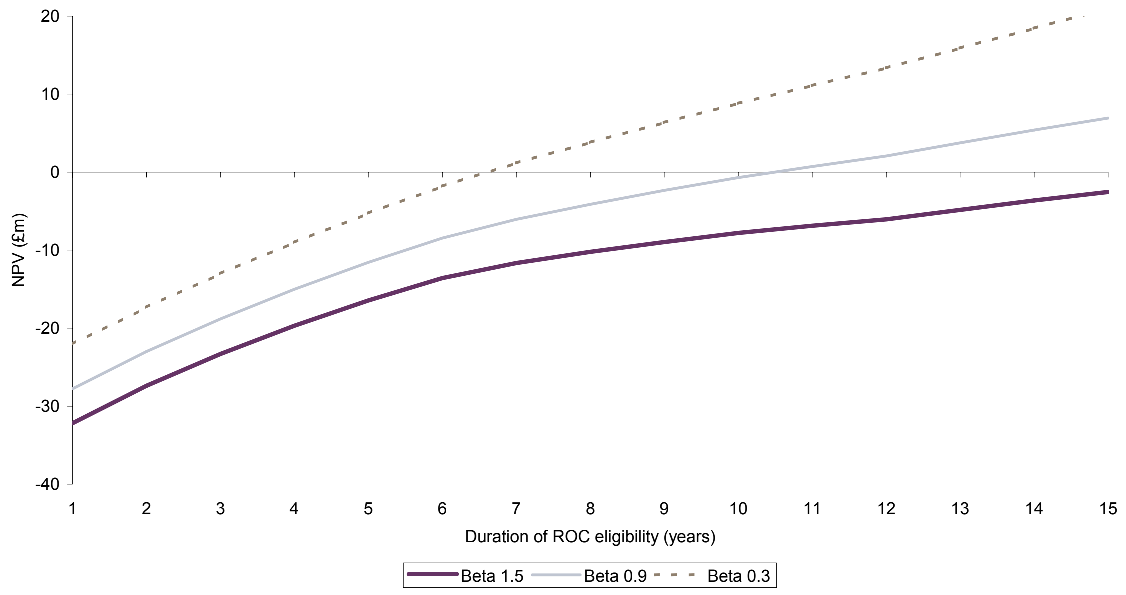
Source: Oxera.

Figure A3.17 NPV for an 80MW onshore wind site at 7m/s with £55/MWh PPA



Source: Oxera.

Figure A3.18 NPV for an 80MW onshore wind site at 7m/s with £60/MWh PPA



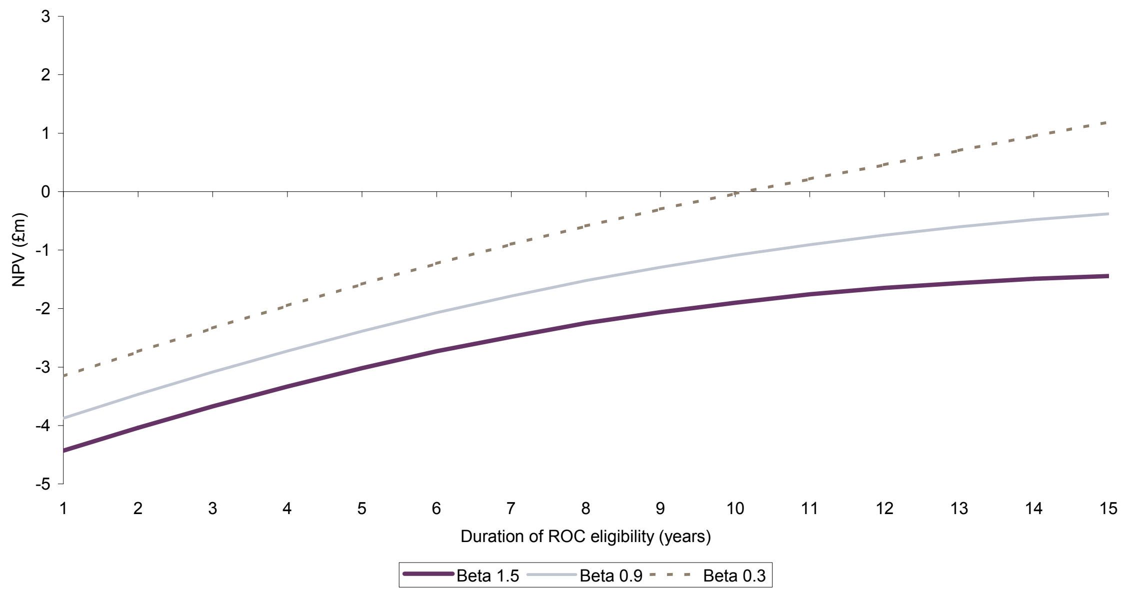
Source: Oxera.

A3.7 10MW onshore wind site with moderate wind speed

This project is also expected to be marginally profitable by 2010. It is based on a 10MW project sited in the east of England with an average wind speed of 7m/s. The key assumptions of the project are:

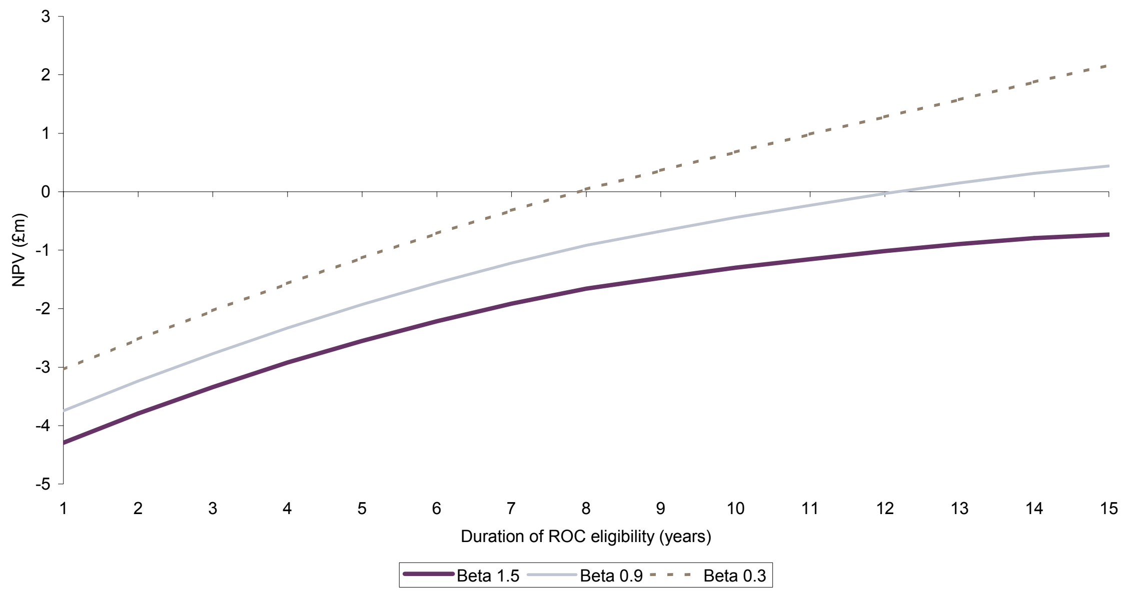
– an economic life of 15 years;
– capital costs of £7.72m;
– annual operating costs of £0.411m;
– an annual output of between 21.9GWh and 27.1GWh.

Figure A3.19 NPV for a 10MW onshore wind site at 7m/s with £50/MWh PPA



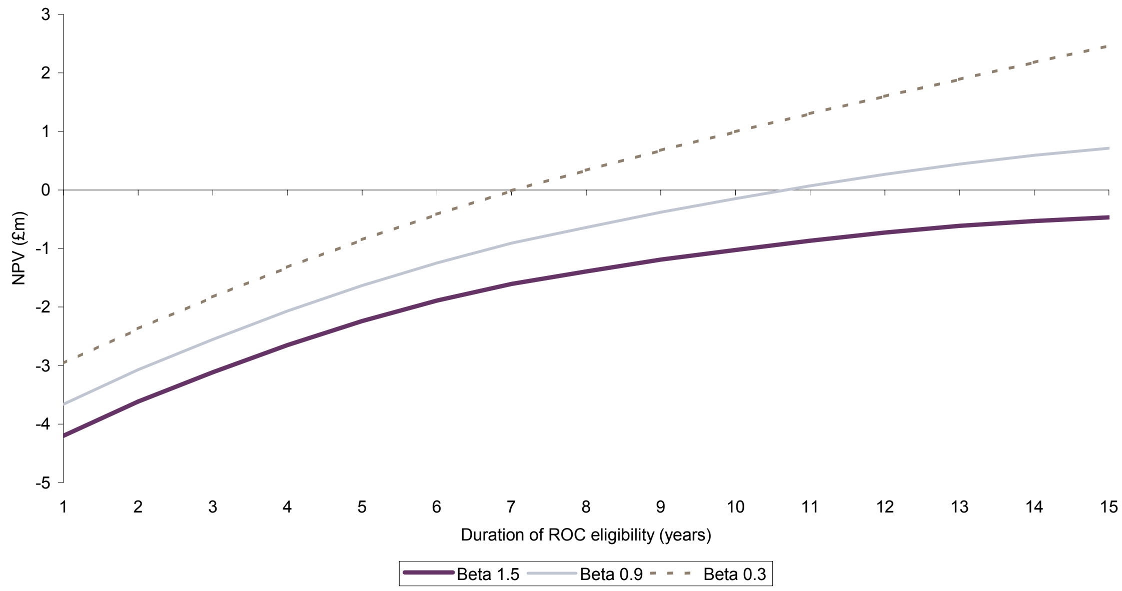
Source: Oxera.

Figure A3.20 NPV for a 10MW onshore wind site at 7m/s with £55/MWh PPA



Source: Oxera.

Figure A3.21 NPV for a 10MW onshore wind site at 7m/s with £60/MWh PPA



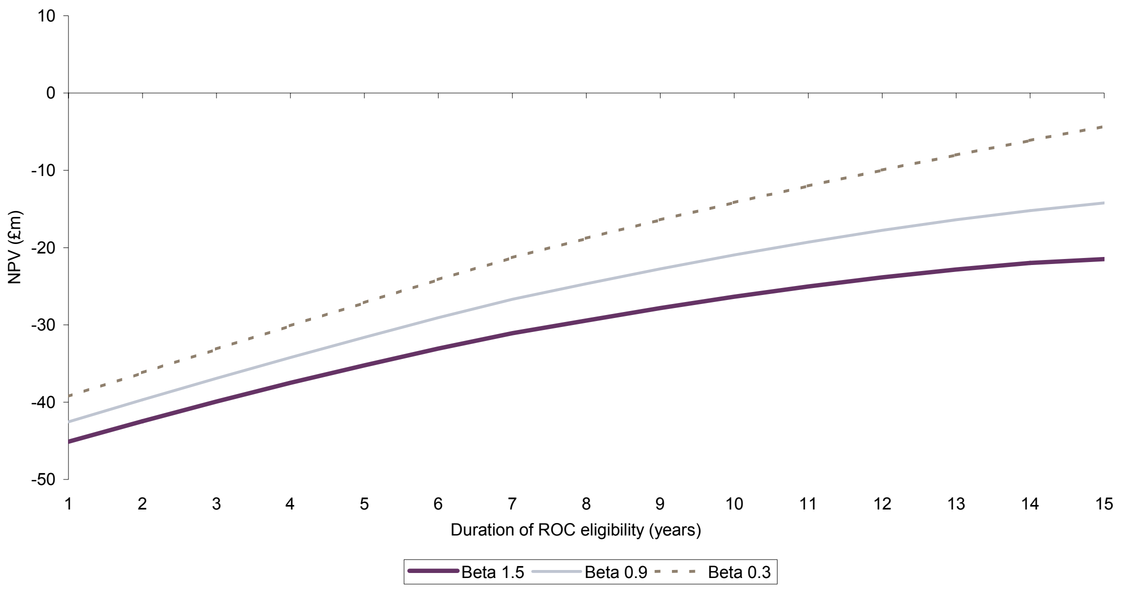
Source: Oxera.

A3.8 80MW onshore wind site with low wind speed

This project represents a potential onshore wind development with limited profitability by 2010. It is based on an 80MW project sited in the north-east with an average wind speed of 6.5m/s. The key assumptions of the project are:

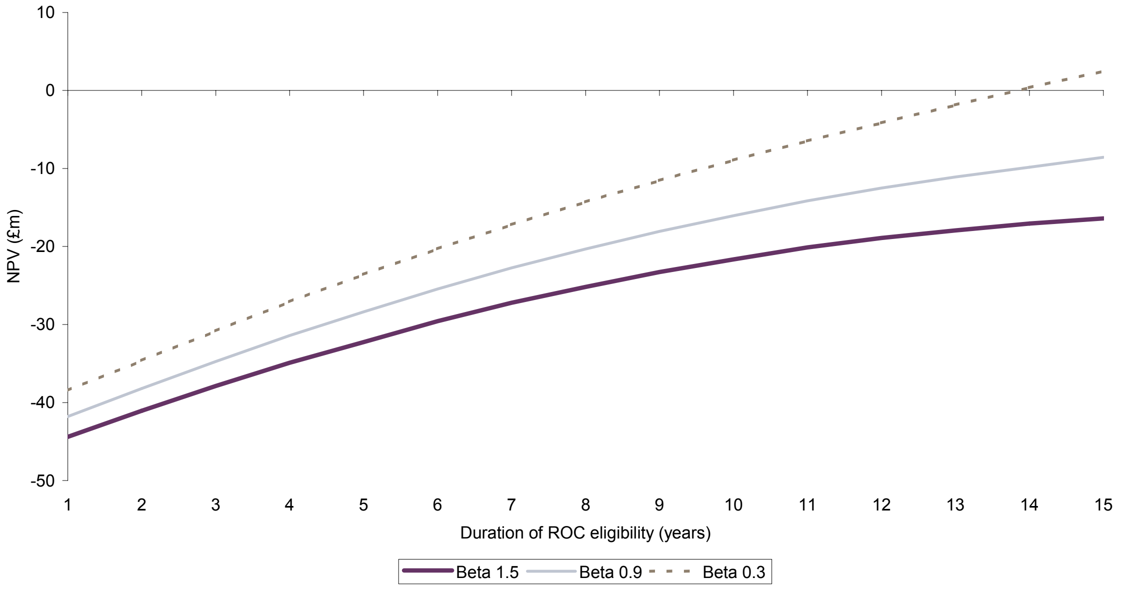
– an economic life of 15 years;
– capital costs of £60.79m;
– annual operating costs of £3.766m;
– an annual output of between 152.8GWh and 188.7GWh.

Figure A3.22 NPV for an 80MW onshore wind site at 6.5m/s with £50/MWh PPA



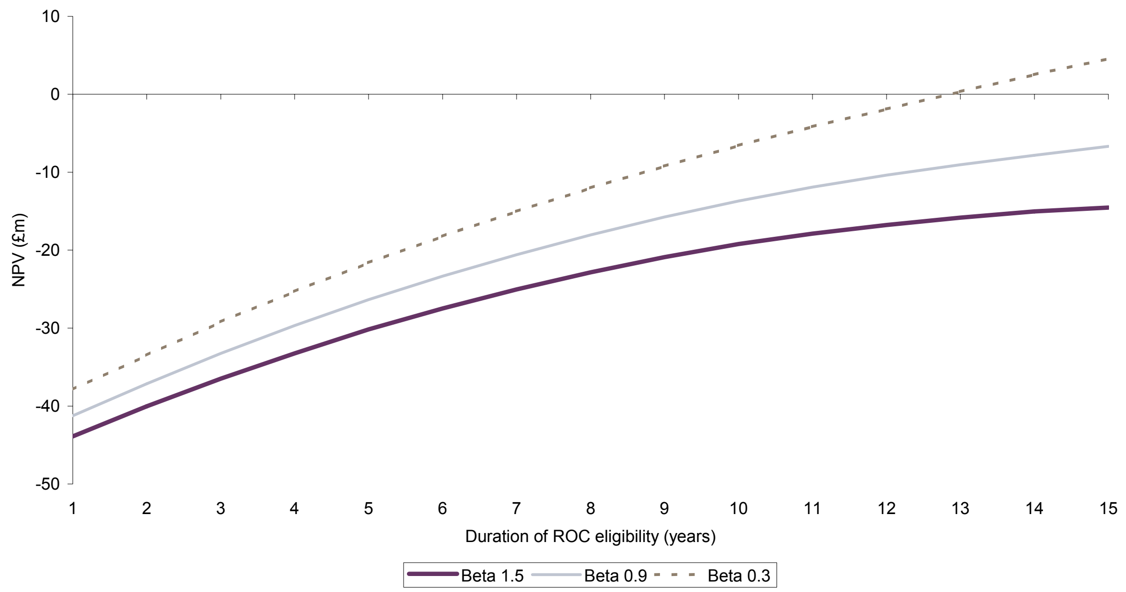
Source: Oxera.

Figure A3.23 NPV for an 80MW onshore wind site at 6.5m/s with £55/MWh PPA



Source: Oxera.

Figure A3.24 NPV for an 80MW onshore wind site at 6.5m/s with £60/MWh PPA



Source: Oxera.

Oxera
Blue Boar Court
Alfred Street
Oxford OX1 4EH
United Kingdom

Tel: +44 (0) 1865 253 000
Fax: +44 (0) 1865 251 172

www.oxera.co.uk