Final Report to

Comhairle Nan Eilean Siar and The Highland Council

An Evaluation of Alternative/Renewable Energy Schemes

by

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in association with

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1.1 Overview

This report has been prepared to provide Comhairle Nan Eilean Siar and the Highland Council (together "the Councils") with an economic evaluation of a range of alternative renewable energy developments – onshore wind, offshore wind, hydro electric and wave/tidal technologies – in the North-West of Scotland. It is designed to provide the Councils with an understanding of the potential financial value of such projects, which the Councils may consider as an input into their deliberations on the issue of community benefits, or indeed in their consideration of developments on Council land or of any partnership arrangements for the development of renewable energy resources that the Councils may be involved in, now or in future.

The report provides an overview of the economics of renewable energy developments, followed by a detailed analysis of seven sample developments, each of different technology and/or size, as shown in Table 1 below. The sizes chosen represent typical sizes of future developments in the given technologies. Onshore wind farms over 50 MW in size are subject to different planning and regulatory procedures to smaller wind farms, and therefore we have considered both a small (40 MW) and large (100 MW) option. Similarly, although most future dammed hydro schemes are likely to be small (e.g. 5 MW), there is potential for at least one much larger development in Scotland, so this has been shown as a separate option.

Table 1 – Technology Types and Sizes in Megawatts (MW)

Technology	Size (MW)
Large Onshore Wind	100
Small Onshore Wind	40
Offshore Wind	200
Large Dammed Hydro	80
Small Dammed Hydro	5
Run-of-River Hydro	1
Wave/Tidal	5

In addition, each of these sample projects was analysed further, according to whether it was assumed to be developed by a large utility company, a smaller private developer, or a joint venture between the community and a private developer. The report summarises the key financial indicators for each of these sample projects and scenarios.

Finally, the report provides a discussion of the risks and sensitivities of renewable energy projects, and concludes with implications for the Councils' consideration of community benefits from renewable energy developments.

1.2 Key Findings

- **The main market driver affecting the economics of renewable energy developments in Scotland is the Renewables Obligation Scotland (ROS)**, which came into force in April 2002. The Obligation requires licensed electricity suppliers to supply a certain percentage of their electricity from renewable sources, which they demonstrate by purchasing Renewables Obligation Certificates (ROCs) from renewable energy generators. The market for renewable energy is driven by the level of the required percentage and the 'buy-out' price, which is the cost levied on suppliers who fail to meet their obligation.

  This market mechanism is designed to drive prices for ROCs up to a level sufficient to make investments in new renewable energy projects commercially attractive. The decision to invest in a project depends upon the forecast price levels and assessment of project-specific costs, revenues and risks.

  The annual obligations under the ROS currently increase to around 10% in 2010. However, the Government recently announced a proposal to increase this to 15% by 2015. These targets are extremely challenging and are therefore likely to lead to commercially attractive conditions persisting in the renewable energy market for some time.

- **Renewable energy capital costs range from around £750,000 per megawatt (MW) installed capacity for wind turbines to twice this amount for wave/tidal developments.** Average annual profits before interest and tax range from around £50,000/MW for wave/tidal up to £200,000/MW for a high-utilisation run-of-river hydro scheme. The pre-tax internal rate of return ranges from 5.6% for the wave/tidal model to 17.7% for run-of-river hydro, with wind farms around 14%.

  Annual average profits expressed as £/MW vary widely between technology types, primarily because the capacity utilisation of renewable energy plant is highly variable. Therefore there is no handy 'rule of thumb' which can predict profits in £/MW for all renewable energy developments. However, it may be possible to use the figures quoted in this report to compare different projects within a single technology type.

- **Average annual profits do not provide a reliable indication of the potential community benefits that could be supported by a scheme.** This is for several reasons. One is that accounting profits are not the same as project cash flows. Another is that different types of developer require different rates of return to satisfy their investors. Therefore a project may be profitable, yet still be considered uneconomic if its rate of return falls below the threshold set by the investors.

- **A more appropriate indicator of the amount of community benefit that a project could sustain over its lifetime is the Net Present Value (NPV)** of the project to investors. This is based on actual cash flows, rather than accounting profits. The project's future cash flows are expressed in terms of their present value by discounting by a factor appropriate to the risk of the project and the nature of the investor. The NPV is simply the sum of these discounted future cash flows. Generally, an investor will only consider investing in projects with a positive Net Present Value at their threshold discount rate.

- **Under the assumptions used in this report, a wide range of renewable energy investments are commercially viable at a discount rate of 8%**, apart from the wave/tidal scheme, which would only be developed either with Government grant support or in the interests of research and development. However, only the run-of-river hydro, large dammed hydro and small onshore wind schemes would be developed at a discount rate of 15%. The range from 8%-15% represents the likely range of discount rates in the private sector (for example from a large utility company to a smaller private developer).

- **A community joint venture would typically require a lower rate of return on its investment and therefore the NPV of the project would generally be higher.** Therefore community joint venture projects could potentially support the highest rates of community benefit (over and above the returns to the community as investors in the scheme).

- **Net Present Value analysis also enables the impact of various different forms of community benefit to be considered.** For example, an up-front lump sum of £13,000/MW would be equivalent to a payment of £1,000/MW (rising with inflation) over 20 years, for a developer using a discount rate of 8%. Benefit payments could also be structured to begin at a low rate and increase as cash flows increase.

- **Ideally, any community benefit should be negotiated with a developer so as to create maximum community benefit at least cost to the developer.** This is best achieved through an understanding of the impact of a community benefit on a project's cash flows and NPV.

1.3 Sensitivities and Risks

A sensitivity analysis was carried out for the 40 MW onshore wind model (utility developer). We would expect the findings of this sensitivity analysis to be broadly similar for all the renewable energy models, but not identical. The key finding of the sensitivity analysis was that the capacity factor (a measure of the proportion of time the plant is generating at full capacity) is the key determinant of profits. Renewable energy resources are inherently variable and hence profits are also variable, both over time and between projects at different locations.

The second most critical factor is the price of Renewables Obligation Certificates, followed by the electricity price. These are also the areas where the perception of risk is currently depressing the prices of long-term Power Purchase Agreements for renewable energy. The price of ROCs is difficult to predict, but the Government's recent announcements have tended to confirm a positive view of future price drivers. There is reason to be optimistic about future electricity prices, due to the fact that prices in recent years have been at historical lows, and most future pressures are upward.

1.4 Community Benefits

The rationale for any renewable energy development to provide community benefits is simply that it utilises a communal resource: the wind, sun, waves and tides are all 'public goods' which are not 'owned' by the developer. In theory, the appropriate level of community benefits would be linked to the impact of the development on all of these communal resources. However, such impacts are extremely difficult to measure.

Therefore while an appropriate starting point for negotiations is the environmental assessment made during the planning process, in practical terms it is also necessary for local authorities to understand the level of community benefits at which the project would become uneconomic. The best measure of this is the difference between the Net Present Value of the project at one particular location, and the NPV of the project at an alternative location where community benefits would not apply.

Given a wide range of alternative locations for renewable energy projects, it is likely that a high community benefit requirement in one area would be 'undercut' by lower requirements in other, perhaps otherwise less favourable, areas. This would tend to drive the realisable community benefits down to a minimum level. However, as more sites are used up, the most attractive remaining sites will be increasingly valuable and there may be more potential to negotiate higher rates of community benefits for developments on these sites. The same applies for sites close to existing grid and road infrastructure.

One option to maximise the value of a community benefit at least cost to the developer may be to negotiate a benefit in the form of additional infrastructure improvements, for example an upgrade to the electricity grid or a road improvement. Similarly, a local manufacturing base that would provide spin-off benefits to the community in the form of employment may also be in the developer's longer-term interest in terms of reducing costs.

Finally, it is noted that Power Purchase Agreements for renewable energy projects typically range from five to fifteen years, and the length of the Agreement should be taken into account in any negotiations over community benefits.

1.5 Conclusions

The following conclusions can be drawn from this report:

- The economics of renewable energy are driven by Government policy in the form of the Renewables Obligation;
- At present this means that a wide range of renewable energy developments are commercially attractive to at least some types of developer;
- However, some technologies such as wave/tidal are unproven and can only be expected to be marginally attractive in the near future;
- Average annual profits vary considerably between technology types, therefore there is no 'rule of thumb' which can predict profits across all renewable energy types;
- The Net Present Value of a project provides a better indication of the potential community benefits that a project could support; and
- Ideally, any community benefit should be negotiated between the developer and the community, so as to create maximum community benefit at least cost to the developer. This is best achieved through an understanding of the impact of a community benefit on a project's NPV. In addition, it may benefit a developer to align a community benefit with the uncertainties in a project's future (for example, the term of a Power Purchase Agreement).

2. INTRODUCTION

IPA Energy Consulting has been asked to provide analysis to assist Comhairle Nan Eilean Siar, the Highland Council and possibly other local authorities, herewith called "the Councils," to understand the potential financial value of alternative/renewable energy schemes in the North-West of Scotland. The purpose of evaluating these projects is to provide the Councils with an understanding of the potential financial value of such projects, which the Councils may consider as an input into their deliberations on the issue of community benefits.

IPA has built a 'Base Case' economic model for a sample project in each of the designated technology and technology sizes: small and large onshore wind, offshore wind, run-of-river hydro, small and large dammed hydro and wave/tidal schemes. The model calculates the electricity generated by each scheme and the revenue arising from the sale of electricity, Renewables Obligation Certificates and other benefits. It also calculates the capital costs involved in construction of a new renewable energy project, and the ongoing operating costs. Depreciation is deducted to arrive at the profit before interest and tax. Interest is calculated separately based on the percentage of the capital cost that is assumed to be borrowed, and tax is calculated after taking various tax benefits such as Enhanced Capital Allowances into account, leading to the profit after interest and tax. The model also calculates actual cash flows in order to arrive at a Net Present Value Calculation.

All of the models are based on information in the public domain, market information and IPA's best estimates of key cost and revenue parameters. Generic economic inputs to the models have been described in Section 4 of this report and technology-specific assumptions are attached at Annex A, together with further background information to aid understanding of the renewable energy market.

In addition, each of these sample projects was analysed further, according to whether it was assumed to be developed by a large utility company, a smaller private developer, or a joint venture between the community and a private developer. The report summarises the key financial indicators for each of these sample projects and scenarios.

Our valuation of the projects is based on considerable experience within the electricity industry and the best public-domain information available. Nevertheless, these models merely represent typical or 'average' projects, and given the volatile nature of electricity markets and the substantial uncertainties that remain about a number of the parameters in the models, it is necessary to understand the implications for the project value if some of the key costs or revenue streams are significantly different from those anticipated. We have therefore provided a discussion of potential risks to a project (Section 5) together with a quantitative sensitivity analysis for one of the sample projects (the 40 MW onshore wind farm, utility developer). In addition, it must be recognised that any individual project will vary from these typical projects in a number of ways according to local conditions.

Our results are presented in Section 5, and in Annex F the Profit and Loss and Cash Flow Statements for each of the designated schemes and developers have been displayed.The stages involved in a typical renewable energy development have been summarised in Annex G.

3. DEVELOPMENT OPTIONS

This report focuses on three development options:

- Large utility developer;
- Small private developer; and
- Community/Landowner/Local Authority/developer partnership.

The impact of each of these options on the project economics has been modelled for each of the technology options. The development options are described in greater detail below.

3.1.1 Large Utility Developer

Most developments in established technologies such as wind and hydro are currently being developed by large utilities, or in the case of wind, large turbine manufacturers such as GE. These companies have the advantage of large capital reserves which they can draw upon to invest in such projects. They can also benefit from being able to offset the losses in the early years of a project against their taxable profits elsewhere. Finally, they can benefit from economies of scale and from synergies with the rest of their business portfolio.

3.1.2 Small Private Developer

Many smaller wind developments and most of the more experimental technologies such as wave and tidal are being developed by small private developers. In some cases, these companies may be offshoots of large utilities or turbine manufacturers, but many others are truly independent. Small developers are exposed to higher risks as they do not have the benefits available to large utility developers as outlined above. They therefore expect higher returns and seek to exploit niches in the market such as those offered by newer technologies, or by focussing on the development stage and selling on to a large utility at construction and operation stage (see Annex G). Typically, development costs are funded by a combination of internal resources and high-risk capital investments from sources such as renewable energy funds or 'business angels' (high net worth individuals). Construction costs would typically require debt financing.

3.1.3 Community/Landowner/Local Authority/Developer Partnership

There are very many possible permutations of a partnership arrangement between a community, local authority and developer. In theory, such a partnership could have several advantages over a development by either a large utility developer or a small private developer:

- The involvement of the community at an early stage would help to minimise community objections to the development;
- The involvement of the local authority may help to streamline the planning process and reduce development costs;
- Any financial contributions from the community or local authority would increase the amount that could be borrowed from a bank, thus enabling larger projects to proceed;
- Community benefits could be negotiated at an early stage between all parties, enabling realisation of more 'win-win' benefits for all parties.

However, there are complex issues to do with taxation of such an arrangement, and limitations on the powers of Local Authorities to invest in such a vehicle. With many partners in such an arrangement, the scope for disagreements and divergent objectives may be as great as the scope for synergies and mutual benefits.

4. COMMON ECONOMIC PARAMETERS

Although this analysis covers several different technologies and project sizes, there are several parameters that are common to them all. This section describes these common economic parameters, explaining the rationale and assumptions that support them.

4.1 The Electricity Market

The GB electricity industry is currently going through some very significant changes. Market and transportation arrangements, especially in Scotland, are undergoing a fundamental redesign, which is creating significant new risks for market participants. Where ten years ago, the industry in GB was dominated by a handful of vertically integrated companies involved in both monopoly and competitive activities, the Government and industry Regulator (Ofgem) has increasingly forced separation between the inherently monopolistic 'wires' businesses (transmission and distribution) and potentially competitive generation/supply businesses. New GB-wide trading and transmission arrangements (known as BETTA) are due to be introduced in 2005, to tackle the dominant position of Scottish Power and Scottish and Southern Energy in Scotland - the last bastion of vertical integration.

The electricity regime is continuing to change and by 2007, when we have estimated that the first power might be expected from any of the modelled projects, the market could look substantially different from now. Nevertheless, we have built economic models around a 'Base Case' for each of the projects, basing the major inputs on market data and IPA's price forecasts. In Section 4.3.4 we discuss the implications for the Base Case model if the schemes were to be introduced before the proposed introduction of the GB wide transmission and trading arrangements in April 2005.

Further background on the history and development of the GB electricity markets can be found in Annex B.

4.2 The Structure of Electricity Trading

In England and Wales (E&W) generators compete in a market. Until March 2001, this market was a compulsory Pool, in which generators bid against each other, in what was effectively an auction, for the right to run in each half-hour. Since March 2001 the Pool has been abolished and generators compete with each other to sell their output directly to suppliers. In Scotland, there is currently no competitive market and almost all generation is provided by the two incumbents, ScottishPower (SP) and Scottish and Southern Energy (SSE).

These electricity markets are considered in more depth in Annex B.

However, the current structure is set to change in 2005 and a GB wide market, based on the current E&W arrangements, will be introduced. This effectively means that all generators will need to enter into bilateral contracts with either suppliers or traders to sell their output. These contracts are commonly termed Power Purchase Agreements (PPAs).

PPAs can vary in both their length and make-up, depending on the type of generation and the requirements of both parties. Contracts can vary in length from a single day to several years and can specify varying amounts of power per half-hour. Power required on an ad-hoc basis and for shorter terms than a day is typically traded either Over The Counter (OTC) or through power exchanges. For example, a generator with a very flexible plant (able to ramp up and ramp down very easily) may not want to enter into a long term contract at a fixed price, as they would then not be able to trade their output in the power exchanges at times of unexpected high demand and consequent high prices.

However, to attract financing generators do generally need to enter into long term power purchase agreements with electricity suppliers or electricity traders. This is in order for a generator to demonstrate reliable profitability to potential lenders and minimise risk. In the modelling of each of the renewable schemes we have assumed that a 100% off-taking agreement at the market price throughout the 20 year period being analysed is in place.

4.3 Project Revenues

The key determinants of the renewable project's revenue will be the value realised from the sale of:

- The power station's electricity output;
- Renewables Obligation Certificates (ROCs); and
- Climate Change Levy Exemption Certificates (LECs).

These are all on a £/MWh basis and are therefore dependent on the amount of electricity generated by the stations. This is determined by the resources available, the amount of time required for routine maintenance and any unplanned shut-downs. These parameters are discussed for each technology in Annex A.

4.3.1 Base Electricity Price

By the time the projects are constructed, there is likely to be a unified GB-wide electricity wholesale market (BETTA). We have therefore produced a GB electricity market price forecast based on our 'central' view of the main price drivers over the course of the project. We have modelled the electricity prices using our specialised in-house modelling tool "ECLIPSE."

Electricity prices are driven by demand/supply fundamentals like any other market-based commodity. Although there is currently an over-supply of generation in GB and real prices have recently been as low as they have ever been, it is expected that as demand increases and old plant closes over the next few years, the demand/supply position will return to balance and prices will rise. Indeed this currently can be seen in the forward electricity curve, which has shown prices rising over the near term.

An EU wide emissions trading scheme is to be introduced in 2005 that will put a market price on the carbon emitted from most major industrial sources (including power generation). This will have the effect of increasing the price of electricity from conventional fossil fuelled power generation. This impact has been included in our electricity price forecast and so is not noted as a separate income stream.

However, all power does not change hands at the base or average price. There are a number of aspects to the electricity market that result in some electricity having greater value than the rest.

Electricity spot market prices in GB vary each half-hour of the day. Movements in half-hourly prices reflect the demand/supply position at different points in the day, week or year. For example, within a week-day, prices increase first thing in the morning and again in the early evening when demand is highest. During off-peak periods, during the night for example, when demand is low, prices fall to reflect the excess of generation on the system. Prices also tend to be higher during the week than at weekends, and higher in winter than in summer.

In order to avoid the risks associated with half-hourly price volatility, generators and suppliers enter into longer-term bilateral contracts at fixed prices. The period of contracts ranges from day-ahead and week-ahead to quarterly and yearly or longer. The price of a contract will vary depending on the 'shape' of the power provided. For example, a 'flat' or 'baseload' contract supplies the same amount of energy in each half-hour. A 'shaped' contract typically provides energy only during 'peak' periods – those periods with high demand – or 'off-peak' periods – those with low demand. Peaking contracts will therefore be more expensive than a baseload contract and off-peak contracts are cheaper than baseload contracts.

Some types of generation are more controllable than others – e.g dammed hydro schemes and pumped storage schemes that can be switched on and off very easily – and so can choose to generate at specific times of the day and hence access the higher prices.

Historically, dammed hydro plant (including pumped storage schemes) has operated at the peaking end of the market – providing power only during periods of highest demand and hence highest price. This maximises the revenue from the limited amounts of water available. Hydro plant also has a role to play as 'balancing' plant. Under the current market arrangements, participants face significant penalties if in any half-hour their contractual position (how much electricity they have bought or sold) fails to match their physical position (how much electricity they actually use or produce). Dammed hydro plant is often used to compensate for any imbalances, because it can be ramped up or down very quickly, both to avoid imbalance penalties and to maintain a physical balance on the system.

Wind power and run-of-river hydro run when the resource is available, i.e. when the wind blows or there is enough water in the river, and thus cannot choose to access the periods of high prices. Similarly, wave and tidal power will run when there are waves and tidal currents.

The electricity price used for all the models, except the dammed hydro schemes, is IPA's forecast of yearly average baseload contract prices over the course of the project, reflecting the value of selling flat power to a third party.

For the dammed hydro schemes we have used IPA's forecast of yearly average peak contracts, reflecting the controllability of such schemes.

Firm Power

Generators who produce more or less energy in any half-hour than they have sold under contract are subject to ***Imbalance charges***. These charges can be penal. In order to minimise these charges the projects require active management, which must provide good quality information flows between the generator and buyer. We have assumed that wind developments of the size analysed will have such systems in place and the risk of the farms not delivering the stated output will be reduced.

However, we recognise that some imbalance charges will be incurred and we have therefore introduced an ‘Access Factor’ which adjusts the electricity prices and represents the risk discount due to the variability of the developments’ output. For example, intermittent generation, such as onshore wind, typically does not achieve the full market price of electricity and the access factor simulates this by reducing the forecast electricity prices correspondingly. The value of this ‘Access Factor’ has been set at 0.75 for onshore wind developments. Offshore wind developments are expected to have steadier output than onshore developments and so we have increased the access factor to 0.8.

Hydro schemes are less prone to output fluctuations but still have some output variability due to variations in seasonal rainfall. We have therefore increased the access factor to 0.85 for the run-of-river hydro model and again further, to 0.95, for dammed hydro schemes due to reflect the controllability of such schemes.

For tidal developments we have set the access factor to 0.9 to reflect its expected regular nature.

4.3.2 Renewables Obligation Certificate (ROC) Value

In addition to a core energy price, renewable projects also receive income from the sale of Renewables Obligation Certificates (ROCs). The power station will earn one ROC for each MWh of electricity produced.

The Renewables Obligation (RO) in England and Wales and the Renewables Obligation Scotland (ROS) came into force in April 2002. Under the Obligations, licenced electricity suppliers are required to supply a certain proportion of their energy from renewable sources, which they demonstrate by purchasing ROCs from ‘green’ generators. This obligation creates a market demand for renewable generation in the form of ROCs. The value of ROCs is driven by a ‘buy-out’ price, the cost facing suppliers who fail to meet their Renewables Obligation. The buy-out price was set initially at £30/MWh (in 2002) and rises with inflation. The ‘buy-out’ money, collected from suppliers who have *failed* to meet their Renewables Obligation, is recycled to those suppliers who *have* presented ROCs, thus creating additional demand for ROCs and further increasing their value. The Renewables Obligations extend to 2027 with the targets rising to 10% in 2010 but with currently no definite increase between 2010 and 2027. However, it is noted that the Deputy Enterprise Minister in Scotland recently announced a strong determination to build and maintain confidence in the industry – implying a favourable view on extension of rising targets beyond 2010.

Currently Renewables Obligation Certificates (ROCs) are trading at around £48/MWh. This is in addition to the income received from the sale of the energy. The value of ROCs in future years will depend entirely on the demand/supply balance. As long as there is a shortfall of renewable generation, the value should remain buoyant. If however, the Government’s renewable target is achieved, i.e. supply exceeds demand, then the value of ROCs will fall, potentially to zero[1].

The target in the statutory instrument is currently 10% of electricity demand to be met by renewable generation by 2010. In August last year the Scottish Executive published a consultation paper[2] looking at increasing Scotland’s renewable energy in the period beyond 2010. This consultation stated that 40% of Scotland’s electricity requirements could

[1] In practice there are reasons to expect that it will not fall below £7/MWh, due to the expected role of biomass co-firing, which carries a cost of fuel estimated at this level
[2] “Scotland’s Renewable Energy Potential – Beyond 2010”. A Consultation Paper. August 2002

realistically be produced from renewable sources by 2020. In March 2003 the Executive officially adopted this target. If this is progressed and further enabling legislation put in place, for example by an increase in the ROC targets, we would envisage the ROC value to remain at a value significantly above the initial buy-out price of £30/MWh.

In the modelling of the ROC values we have assumed an average value of ROCs at £45/MWh going out to 2009 and then a decrease to £35/MWh thereafter. Implicit in these figures is the assumption that generators are able to obtain value from the recycled payments. However, the value of ROCs in a long-term Power Purchase Agreement has been assumed to be 25% less than the full market value, reflecting the risk taken on by the off-taker.[3]

4.3.3 Climate Change Levy (CCL)

In April 2001, the Climate Change Levy (CCL) was introduced in the UK. This is a tax on the consumption of energy by non-domestic customers. The tax on electricity consumption is 0.43p/kWh (or £4.30/MWh), but electricity produced from renewable sources is levy exempt. This creates an additional demand for electricity produced from renewable sources. Consumers are prepared to pay a premium for Climate Change Levy Exemption Certificates (LECs) in order to avoid paying the levy. This premium is an extra source of income for the renewable projects, and more recently also for Combined Heat and Power (CHP) plants, which are also levy exempt.

Market intelligence suggests that between 50% and 80% of the full value of LECs is being paid to generators. In our analysis, we have assumed that generators will achieve 70% of the value. For the analysis we have assumed that the LECs are valued at this level throughout the project lifetime.

The Climate Change Levy is unpopular with industry and is complicated by the impending introduction of emissions trading in 2005 (analogous to an upstream carbon tax), which is incompatible with the current CCL legislation (a downstream carbon tax). It may therefore be abolished in its current form and at its current level. However, we have kept the CCL constant at its current level (represented in nominal terms) throughout the model as there are currently no indications from government that the value of this tax will change or indeed be abolished once emissions trading is introduced.

4.4 Project Costs

In return for generating electricity, the schemes will incur charges for using the electricity system and require maintenance throughout their lifetimes. These are discussed further in the following sections.

4.4.1 Transmission Losses

Not all power produced by the schemes will reach end consumers. Some energy is lost due to the electrical resistance of the equipment and cables. On average approximately 2% of energy produced is lost during transmission and a further 6-7% during distribution. In E&W, generators meet 45% of the costs of transmission losses and suppliers pay the rest. Charges are uniform and are charged on an average basis, regardless of a generator's location.

[3] This estimate is based on a number of confidential sources for the level of ROC payments in current Power Purchase Agreements.

Generators in Scotland do not currently pay any charges for losses. Instead the regulated Scottish market price is adjusted downwards to incorporate losses.

The enlargement of the existing E&W electricity market to Scotland to create common GB-wide trading and transmission arrangements will include the extension of the charging arrangements for transmission losses.

In E&W changes have been proposed to the current losses charging mechanism, so that it more accurately reflects the fact that the further energy has to travel, the greater the losses. This would result in the generators located farthest from demand centres (such as those in the north of Scotland) picking up a greater proportion of the losses costs than those located in the south of England, for example. This change is to be introduced in April 2004 prior to the introduction of BETTA in 2005. However, the Department of Trade and Industry (DTI) is publicly opposed to a zonal losses arrangement for BETTA and prefers the current 'average' arrangement in E&W. As this is still a contentious issue we have modelled the losses on the current arrangement in E&W, on the basis of BETTA being an extension of these, and that all generators will meet 45% of the costs of transmission. We note that Ofgem have recently published a consultation document on transmission investment and renewable generation (27th October 2003) and that the new Chairman of Ofgem has expressed support for Scottish generators on this issue.

4.4.2 Connection and Transmission Use of System Charges

We highlighted in the Phase 1 report that the Electricity Regulator (Ofgem) favours a "shallowish" connection charging policy, whereby the cost of the connection works are paid directly by the generator, but reinforcement works further away are recovered from all system users. We have therefore treated all electrical connections for the different technologies as shallowish in line with the Regulator's current thinking. The shallowish charges borne by a generator consist of two components, namely the switchgear costs and the line cost per km (i.e. how close the site is to the existing electrical grid). These have been taken into account in the specific capital expenditure costs for each project, whereas the reinforcement costs have been taken into account in the transmission network use of system charges as discussed below.

For example, a wind farm involving a 10km overhead line connection to the grid at a cost of approximately £72,000/km (trident woodpole line installed in a harsh environment) plus a 132/33 kV transformer at a cost of around £345,000 (45 MVA design) plus 1 transformer bay and 1 line bay (combined cost of around £500,000) would cost the developer a total of around £2.02 million (allowing for an additional 55% in transport, civil works and commissioning costs on the capital items). A further £1.2 million would be borne by the network operator under a 'shallowish' connection policy.

As well as paying the costs of connecting to the local network, a generator currently also pays charges for using the greater system – Transmission Network Use of System (TNUoS). Under the proposals that are currently being considered for the new GB-wide transmission arrangements, SSE's current uniform charges (Section 4.3.4) would be replaced by a GB-wide zonal charging mechanism. This would target costs at generators located in areas where there is insufficient transmission capacity, largely because of a surplus of generation over demand. Generators in the north of Scotland are likely to face the most penal charges in GB. We have separately modelled the extension of the existing E&W zonal charging methodology to Scotland, which suggests that north of Scotland generator transmission use of system charges would be about £17/kW. We have assumed that under BETTA generation *in Scotland* connected at 132kV and above will be treated as transmission and subject to generator TNUoS charges.

Table 2 below shows those generators connected to the transmission system and therefore liable for generator TNUoS Charges.

Table 2- Technologies connected to the Transmission Network

Technology	Size (MW)
Large Onshore Wind	100
Small Onshore Wind	40
Offshore Wind	200
Large Dammed Hydro	80

4.4.3 Distribution Use of System Charges

Under the current structure of distribution charges, embedded generation pays the full cost of a "deep connection" but does not pay distribution use of system charges.

Ofgem is currently consulting on changing the structure of distribution charges, for 1 April 2005, such that the connection charge element is made shallower and a new generator Distribution Use of system (DUoS) charge is introduced. However, there are no firm proposals on what the likely change to connection charges would be, or how the new generator DUoS charge would be constructed. We have therefore provided an average generation DUoS charge, based on our best estimation of the likely generator charges, for those renewable schemes connected to the distribution network. Table 3 below shows those generators connected to the distribution system.

Table 3 - Technologies connected to the Distribution Network

Technology	Size (MW)
Small Dammed Hydro	5
Run-of-river hydro	1
Tidal	5

4.4.4 Operation and Maintenance Costs

Each different technology has different operation and maintenance (O&M) routines associated with them. For example the more developed technologies, such as run-of-river hydro schemes will require less maintenance than the newer, less developed technologies such as wave-tidal schemes.

Typically O&M costs are quoted as a percentage of turbine costs (for wind power) or as a percentage of the total capital costs (for hydro schemes). The rules-of-thumb used in our analyses are shown in the table below.

Table 4 – Operation and Maintenance Costs

Technology	O&M Cost Basis
Onshore Wind	2% of turbine Capital Costs
Offshore Wind	4% of turbine Capital Costs
Run-of-River Hydro	2.2% of Capital Costs
Dammed Hydro	2.2% of Capital Costs
Tidal	4% of turbine Capital Costs

4.4.5 Business Rates

In Great Britain electricity generating stations are required to pay Business Rates to their local authority. Rates differ slightly between England & Wales and Scotland. For our analyses we have used the current rateable values applicable in Scotland.[4] These are shown in the following table.

Table 5 – Business Rates

Technology	Rateable Value, £/MW
Wind Power (Onshore and Offshore)	5,000
Water Power (Run-of River and Dammed Hydro)	10,000
Tidal Power	5,000

The current Scottish rates of 47.8p in the pound are applied to each of the rateable values.

4.4.6 Land Rental Costs

Land rental costs have not been included specifically as an annual cost in the financial models of the various schemes on the basis that the level of rental that the landowner will be able to get will be part of the negotiations as the project develops. However, we are aware of rental agreements to landowners in the range of 2% - 4.5% of gross output. There is the potential for this to be increased if the landowner is prepared to contribute further to the development by, for example, putting up some of their own money to fund the development.

One exception to this is the model of the offshore wind farm where we have included the Crown Estate lease of 2% of Gross Revenue, as per the DTI's "Future Offshore" consultation[5], in the calculations.

Land rental payments are negotiated between the developer and landowner at the beginning of a project. If the Council owned the land in which a proposed development was to take place, then it would be able to charge rental payments. There are a number of different ways in which these may be structured, as highlighted below, depending on the level of risk that the landowner is willing to take.

[4] Scottish Statutory Instrument 2000 No. 86 The Electricity Generators (Rateable Values) (Scotland) Order 2000
[5] Future Offshore A Strategic Framework for the Offshore Wind Industry, DTI, November 2002.

- **Fixed annual income:** As this is not dependent on the output of the project, there is no upside (or downside) for the landowner. This is a low risk option and could be based on a £/MW figure or simply a lump sum for the rental of the land. An alternative to this would be a one-off payment at the start of the project, although developers tend to prefer annual payments due to the capital-intensive nature of renewable projects at the beginning of the development.

- **Volume sharing contract:** The revenue received from the project can be linked to the amount of electricity produced on a £/MWh figure. This has a higher risk associated with it, as it is dependent on the amount of electricity generated at the site. The reverse is also true, as if more electricity is generated then the rental will also be higher.

- **Fixed income + volume sharing:** This is essentially an amalgamation of the first two options, having a guaranteed fixed income with an additional revenue stream related to the success of the project. The risks associated with this are not as great as for a straight volume sharing contract, as the landowner would always receive some revenue, even if no electricity was produced at the site.

4.4.7 Market-Related Charges

There are three further charges related to market participation that must be considered in any financial model of a renewable energy project.

In E&W (and consequently in Scotland following the implementation of BETTA in 2005), a ***Balancing Services Use of System charge*** (BSUoS) is levied on all generators and suppliers according to their metered production or consumption in each half hour. This charge covers NGC's costs of maintaining the system in balance on a minute by minute basis. For the financial year 2002/03, BSUoS charges averaged £0.61/MWh for each of suppliers and generators and this is the value assumed in the financial model.

The management of the Electricity Trading Arrangements in E&W is performed by the Balancing and Settlement Code Company (BSCCo – Elexon). All licenced electricity companies are required to sign the Balancing and Settlement code (BSC) and incur a nominal charge for its procurement, operation and management. For the financial year 2002/02 this payment has been £0.11/MWh and this is the value assumed in the financial model.

Thirdly, excess money paid by BSC Parties in Imbalance Charges is redistributed amongst all parties on a scale proportional to their volume of credited energy. This redistribution is paid as ***Residual Cashflow Reallocation Cashflow (RCRC).*** Since the start of NETA, however, the RCRC payment has been negligible. We have modelled this payment as £-0.03/MWh which is representative of the average RCRC payment.

4.5 Embedded Benefits

Embedded Licence Exempt Generators (ELEGs) in E&W such as the tidal, small dammed hydro and run-of-river schemes (i.e. Licence Exempt Generators that are connected to the Distribution system[6]) are deemed to net off local demand, so are considered not to be making use of the Transmission System. In this situation Generators will not be liable for associated charges, which could include Transmission Network Use of System (TNUoS), Balancing

[6] A generator with output capacity of 50MW or less is licence exempt and a generator with capacity of 50MW-100MW can apply to be licence exempt.

Services Use of System (BSUoS) and transmission losses amongst others. These avoided charges are collectively known as embedded benefits.

National Grid Transco produce a schedule of Transmission Network Use of System (TNUoS) demand charges (Annex E) for each fiscal year. Those areas where demand is greatest and generation lowest, such as in London and the South West, pay higher charges than those customers located in lower demand/higher generation areas such as regions in the North of England.

We have modelled a simplified version of the current England and Wales methodology for the calculation of TNUoS demand charges to the GB market. Our results suggest that a negative demand charge will be seen in Scotland. This will not only lead to suppliers being paid for their customers to use the transmission network, it would also result in what is currently an embedded benefit (the ability to reduce suppliers demand charges) becoming an embedded cost. The kW tariff modelled is -£8/kW, indicating that any generator connected to the SSE distribution system will pay £8/kW.

It seems likely that the acceptability of negative demand charges will come under scrutiny during the development of the BETTA arrangements. However, as there is currently no indication as to what will happen to the demand TNUoS we have assumed that the current methodology in E&W will be transferred as is.

We have also assumed for those schemes connected to the distribution networks that a generator will receive a payment of BSUoS at £0.61/MWh, BSCCo at £0.11/MWh and RCRC at -£0.03/MWh[7]. The value of the transmission losses benefit currently represents an increase in metered generation in the region of 1%. However, this will change once the zonal average loss arrangements are introduced in April 2004. At this time, the value will depend on which distribution network the generator is connected to and could range from 3% in areas of Scotland to -1% in England and Wales. As there is still uncertainty around this we have modelled the benefit as 1%.

Generators connected to the distribution system will also incur distribution losses. These losses are usually agreed between the generator and distributor at the time of connection and can either be positive or negative charges. These distribution losses have been incorporated in the modelling of the schemes at an average loss of 1%.

The model assumes that any licence exempt generation (in our analysis, small dammed hydro, run-of-river hydro and tidal) connected to the Grid Supply Point (GSP) group is eligible for these embedded benefits and so will be paid on the basis of its metered generation. Neither of the large wind schemes or the large dammed hydro scheme analysed will be eligible for these embedded benefits, as they will be directly connected to the Transmission system.

4.6 Financing Parameters

4.6.1 Debt Finance

A bank will look at a project's cash flows and risks in order to determine the amount it may be willing to lend, and at what interest rate. We have assumed that, in the current market, banks will not be willing to be exposed to market risk (i.e. the risk of a collapse in prices).

[7] As of the 5th November 2003 licence exempt generators will be able to directly access embedded benefits associated with BSUoS, transmission losses and BSCCo costs.

Therefore it has been assumed that projects will have a long-term Power Purchase Agreement (PPA) in place before going to a bank for debt finance. The bank will then look at the credit-worthiness of the counterparty (i.e. the risk of the counterparty failing and thereby not paying out the terms of the contract, if prices collapse) before making their decision. Since the credit-worthiness of the counterparty can only be assessed on a case by case basis the following debt/equity ratios and interest rates have been based on the characteristics of the technology and developer type alone. In practice, a wide combination of debt/equity ratios and interest rates is possible for any particular project. For example, if a project has a shorter-term PPA, a bank may reduce the amount it is willing to lend, increase the interest rate, or a combination of both. Therefore it should not be assumed that all projects will necessarily be able to borrow at the interest rates assumed here.

4.6.2 Debt/Equity Ratio

The debt/equity split for each of the developer types is discussed below.

- ***Large Utility Developer:*** A large utility developer may be able to finance the project completely from equity and we have thus assumed 100% equity financing, in order to provide a 'Base Case'. In practice, however, a utility will seek to increase its 'gearing' by borrowing from a bank, in particular for larger projects. The effect of increased gearing is discussed in the Sensitivity Analysis section (section 4.3.3).
- ***Smaller Private Developer:*** A smaller private developer is unlikely to have sufficient funds available to finance the entire project. They may also look to maximise their debt in order to get greater returns on their investment (as the repayment of debt is tax deductible). They will therefore most likely approach a bank for the balance required. The amount which banks will be willing to lend is based on the Debt Service Cover Ratio (DSCR) of the project. This is the ratio of the revenue minus the yearly operating costs to the total debt repayments. In modelling each of the schemes we have assumed that for a bank to lend money they require a minimum DSCR of around 2.0 (for proven technologies with a PPA in place). This has been increased to 3.0 for near market technologies (offshore wind) and 4.0 for unproven technologies (wave/tidal). The level of debt which the developer can expect to receive will therefore be dependent upon the particular project. For each typical project we have calculated the amount of debt available to the developer based on this 'rule of thumb'.
- ***Joint Venture:*** A third option is for a smaller private developer to go into partnership with another party. IPA has been asked to examine the case of a joint venture between a smaller private developer, an association of crofters/landowners, and a local authority trust fund. In this case it has been assumed that the principal value that the joint venture has to offer is the value of a project with planning consent and agreements in place with crofters/landowners. In addition, we have assumed that the local authority trust fund is able to contribute grant funds totalling 10% of the overall financing costs. The debt/equity ratio has been calculated based on the DSCR as above.

4.6.3 Debt Interest Rate

For all projects requiring debt we have assumed an interest rate depending on the proven capabilities of the technology. The current yield rate for 15-year gilts quoted in the *Financial Times* is around 4.85%. This represents a virtually risk-free minimum cost of capital over 15 years and takes into account recent movements in short-term interest rates, plus expectations for the future. We estimate that proven technologies with a PPA in place should be able to borrow at interest rates 1-2% above these rates, and less proven technologies at slightly higher rates, as shown below:

- Proven technologies (onshore wind, dammed hydro, run-of-river hydro) - interest rate of 6.5%;
- Near market technologies (offshore wind) – interest rate of 7%.
- Unproven technologies (wave/tidal schemes) – interest rate of 7.5%.

The term over which the debt is to be repaid is assumed to be 15 years.

4.6.4 Discount Rate on Equity

In order to value future cash flows, it is necessary to apply a discount rate to convert them to a Net Present Value (if positive, it provides a good indication that the project will be profitable). The discount rate used is the required rate of return on equity required by the developer, which in turn is based on the opportunity cost of capital (i.e. what that money could earn if invested elsewhere) and the risks associated with the project. We have assumed the following post-tax discount rates in our modelling:

- ***Large Utility Developer:*** Discount rate of 8%. A typical discount rate for conventional power generation is in the region of 6.5-7.5%. Given the risks inherent in renewable energy developments, a higher discount rate would be appropriate. This would take account of the risk involved in pre-development costs (environmental appraisals, resource monitoring, planning applications and consultations, etc) for a portfolio of potential projects, only some of which would be taken through to implementation. However, this value at risk in pre-development is small compared with the value of a completed project, therefore the impact on the discount rate is relatively small. This discount rate is consistent with a 'Base Case'.
- ***Smaller Private Developer:*** Discount rate of 15%. A private developer would be looking for higher returns on a project than a utility, because a private developer would have a smaller portfolio to spread its risk over. This discount rate represents the higher end of the likely range.
- ***Joint Venture:*** Discount factor of 6%. The investors would be the partners in the joint venture, who would be expecting a return better than that which can be obtained from banking and savings accounts, but lower than that expected by an independent equity investor, due to placing a greater value on the social and environmental benefits of the scheme. A return of 6% is also consistent with typical public sector discount rates, and with the returns from existing community cooperative renewable energy developments.[8] This represents the lower end of the likely range.

4.6.5 Capital Allowances

All projects are assumed to be eligible for 25% capital allowances (in other words their taxable profits are reduced by 25% of capital expenditure over a four year period commencing in the two years when the expenditure is incurred. Unutilised allowances can be carried forward.

[8] For example, returns of 5.6% to 6.6% are quoted for Baywind Energy Cooperative in REFOCUS, Sept/Oct 2003, page 46.

4.6.6 Taxation Rate

Different developer types will have different tax regimes applied to them. These are discussed below.

- ***Large Utility Developer:*** A large utility developer will probably be able to get some form of tax relief, whereby it can utilise the losses created by capital allowances during construction, and offset these against the taxable profits of the parent company. The renewable development effectively benefits via this benefit to the parent company. We have assumed that they are able to offset 100% of their losses against profits elsewhere. Any profit will be taxed in line with the corporation tax bandings (Annex H) and the value of the implicit relief is therefore set at the maximum tax rate of 30%. When the project is earning profits, these would also be taxed at 30%.
- ***Smaller Private Developer:*** We have assumed that a private developer will be unable to have access to these forms of relief and will simply be taxed on their earnings from the project in line with Corporation tax rules, being unable to utilise capital allowances until such time as the project is earning profits.
- ***Joint Venture:*** We have assumed that the joint venture will be taxed in the same way as a private developer and that it will not have access to relief. However, in practice it may be possible that the Joint Venture entity would initially be set up as a partnership (of which there are several types) between the various parties. This might then allow each investor to access their share of losses to offset against profits elsewhere.

5. RESULTS

5.1 Summary of Results

Table 6 below summarises the capital costs and annual average profit before interest and tax for the seven technology models, over the assumed twenty year operating lifetime of the schemes. It also shows the pre-tax Internal Rate of Return (IRR), which is an indicator of the attractiveness of a project. An IRR higher than the returns required by banks and investors is considered attractive.

The choice of developer type does not affect these figures, since it only has an effect on interest and tax. The results have been expressed in terms of pounds per megawatt installed capacity (£/MW), and all figures in this report have been quoted in nominal terms (i.e. taking inflation into account). This means that the average profit shown here is higher than the average profit in today's money.

Table 6 – Summary of Profits – Nominal Terms

Technology	Capital Costs (£/MW)	Annual Average Profits Before Interest and Tax (£/MW)	Internal Rate of Return (%)
Large Onshore Wind	750,000	84,571	14.0%
Small Onshore Wind	750,000	87,236	14.4%
Offshore Wind	1,000,000	106,162	13.4%
Large Dammed Hydro	1,063,000	145,687	16.0%
Small Dammed Hydro	1,450,000	130,928	11.7%
Run-of-River Hydro	1,240,000	196,433	17.7%
Wave/Tidal	1,500,000	54,512	5.6%

The table shows that annual average profits expressed as £/MW vary widely between technology types. This is because the capacity utilisation of renewable energy plant is highly variable (for example, a wind farm may only operate at 30% of its rated capacity due to fluctuations in the level of the wind resource). Therefore there is no handy 'rule of thumb' which can predict profits in £/MW for all renewable energy developments. However, it may be possible to use the above figures to compare different projects within a single technology type.

It is also clear from the results that the returns offered by wave/tidal developments are currently too low to be attractive to most investors. However, the economics of such projects may be improved by Government funding. Large hydro and run-of-river hydro are likely to be the most attractive technologies, followed by onshore wind farms.

5.1.1 Potential Community Benefits

Average annual profit does not provide a reliable indication of the potential community benefits that could be supported by a scheme. This is for several reasons. One is that any such benefits will need to be paid in cash, and actual cash flows are not the same as accounting profits. Another is that different types of developer require different rates of return to satisfy their investors. Therefore a project may be profitable, yet still be considered uneconomic if its rate of return falls below the threshold set by the investors.

A more appropriate indicator of the amount of community benefit that a project could sustain over its lifetime is the Net Present Value (NPV) of the project to investors, as shown in Table 7 below. This is based on actual cash flows, rather than accounting profits. The project's future cash flows are expressed in terms of their present value by discounting by a factor appropriate to the risk of the project and the nature of the investor. The NPV is simply the sum of these discounted future cash flows. Generally, an investor will only consider investing in projects with a positive Net Present Value at their assumed discount rate.

Table 7 –Net Present Value (£/MW)

Technology	**NPV (Utility Developer)**	**NPV (Private Developer)**	**NPV (Joint Venture)**
Assumed Discount Rate	**8%**	**15%**	**6%**
Large Onshore Wind	209,080	-3,832	309,779
Small Onshore Wind	229,121	2,648	336,901
Offshore Wind	242,222	-74,005	365,106
Large Dammed Hydro	441,131	93,324	645,693
Small Dammed Hydro	297,060	-120,241	397,153
Run-of-River Hydro	655,383	254,410	1,145,299
Wave/Tidal	-242,800	-505,603	-237,583

Table 7 shows that, under the assumptions used in this report, a wide range of renewable energy investments are commercially viable at a discount rate of 8%, apart from the wave/tidal scheme, which would only be developed either with Government grant support or in the interests of research and development. This correlates well with the current state of wave/tidal technology in the market.

In general, the utility developer and private developer NPVs represent the range of possible values that the private sector would place on renewable energy developments. A large utility developer enjoys some commercial advantages over a private developer in terms of having a larger portfolio and tax benefits, but the main difference is the lower discount rate. A community joint venture, on the other hand, would require a lower rate of return on their investment and therefore the NPV of the project would be higher.

Net Present Value analysis enables the impact of various different forms of community benefit to be considered. An up-front community benefit lump sum would simply be subtracted from the project's NPV (assuming the developer had sufficient cash available). Alternatively, a benefit payment could be spread out over future years, in which case each year's community benefit would be subtracted from that year's cash flows. For example, an up-front lump sum of £9,995/MW would be equivalent to a payment of £1,000/MW (rising with inflation) over 20 years, for a developer using a discount rate of 12%. Benefit payments could also be structured to begin at a low rate and increase as cash flows increase.

Ideally, any community benefit should be negotiated with a developer so as to create maximum community benefit at least cost to the developer. This is best achieved through an understanding of the impact of a community benefit on a project's cash flows and NPV.

5.2 Base Case Results

Detailed profit and loss and cash flow statements for each project are attached at Annex F.

From each of the detailed statements we have extracted the annual average profit before interest and tax (PBIT) and the annual average profit after interest and tax (PAIT). These are presented in Figure 1 and Figure 2 in terms of £/kW and £/MWh respectively. These are quoted in nominal terms, i.e. taking inflation into account.

Figure 1 – Profits Before Interest and Tax For Different Technologies (£/MW)

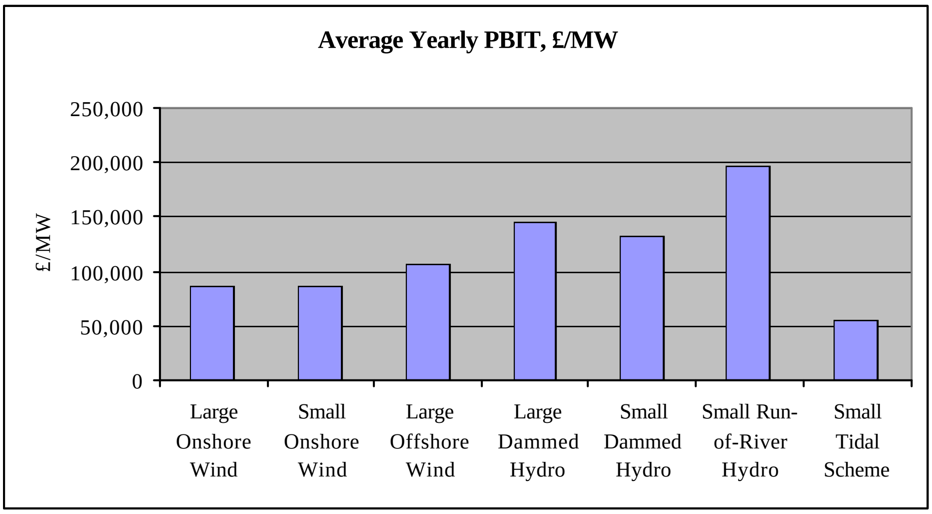

Figure 2 – Profits Before Interest and Tax For Different Technologies (£/MWh)

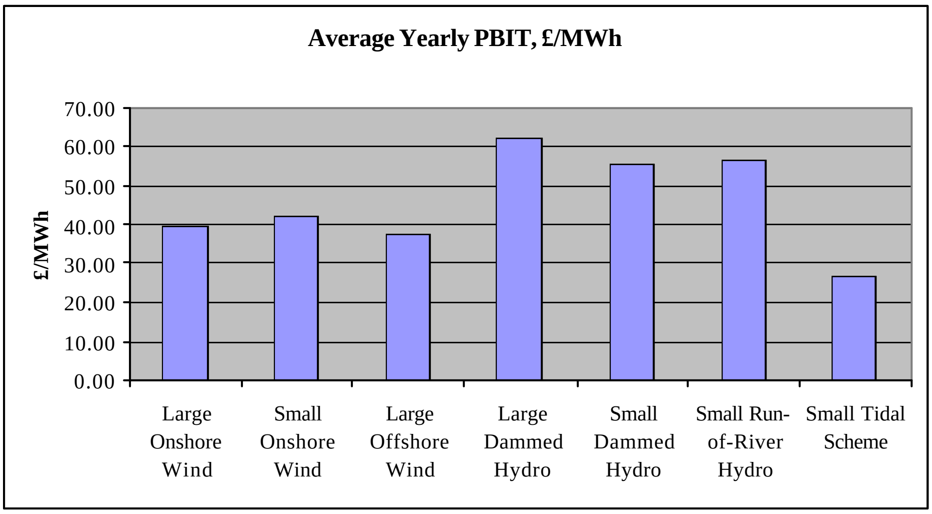

Figure 3 below shows the anticipated annual revenues, in nominal terms, for the large onshore wind scheme over its assumed 20-year lifetime. The dip in the ROC income in 2010 is attributed to the drop in the forecast ROC price in that year. In the large windfarm case we have assumed that the turbines are installed over two years (2007 and 2008), and consequently decommissioned over two years (2027 and 2028) – hence the decrease in revenues over those two years.

Each of the technologies will follow a similar pattern to that shown here but to varying degrees of profitability. The shape of the curve remains the same and therefore this chart has not been repeated for each technology

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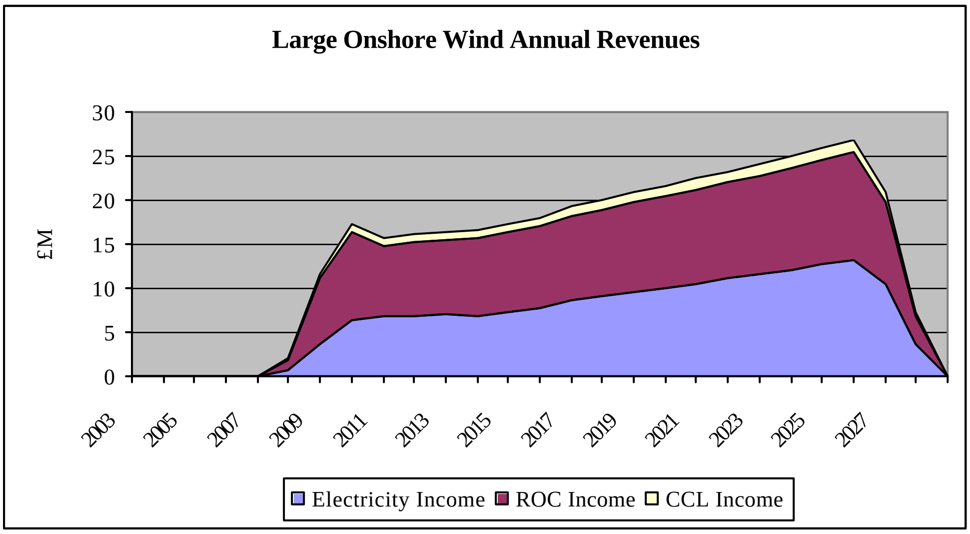
Figure 3 – Anticipated Annual Revenue for Large Onshore Wind



The annual profits before interest and tax (per kW and per MWh) for each of the technologies are shown in Figure 4 and Figure 5 respectively.

Figure 4 – Annual Profits Before Interest and Tax, £/MW

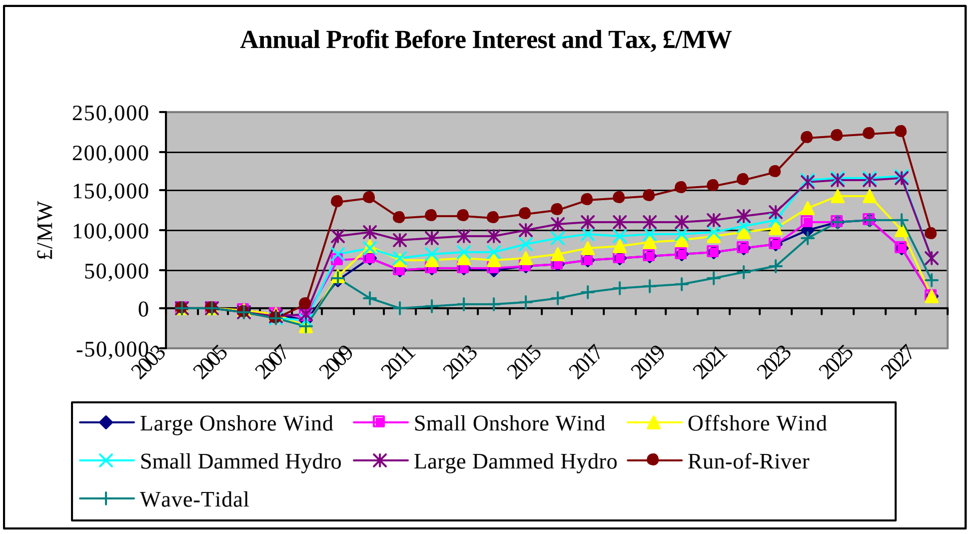
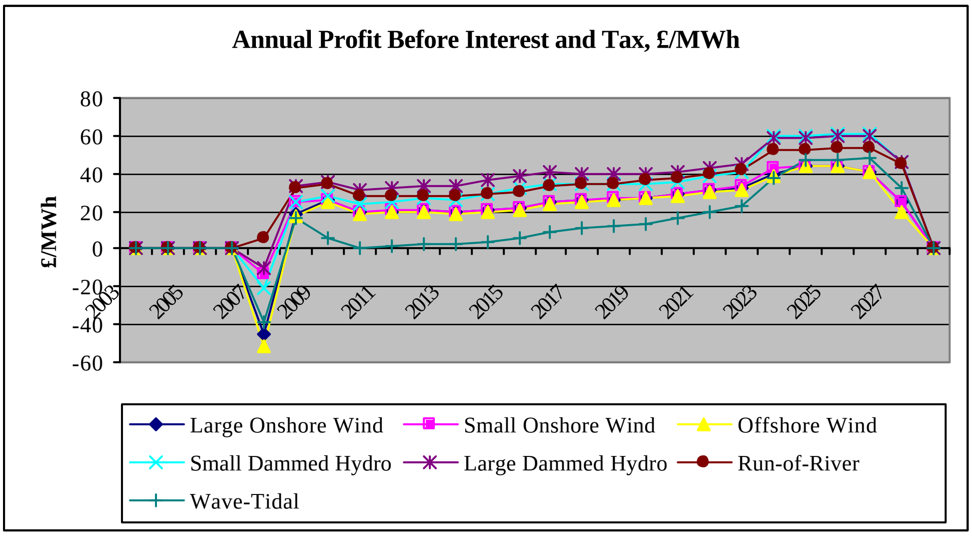


Figure 5– Annual Profits Before Interest and Tax, £/MWh



The modelling shows that the highest profits before interest and tax are achieved from hydro schemes, reflecting the fact that this technology is the furthest advanced of all those investigated. This is followed by the wind schemes and the tidal scheme.

Profits start to be earned by the projects in 2007 when the first energy is generated from the schemes. By 2027, when the projects start to be decommissioned the annual profits tail off as in Figure 3 – Anticipated Annual Revenue for Large Onshore Wind.

The different developers have different tax regimes applied to them, which impacts upon the post-tax profitability of the schemes. Figure 7 and Figure 8 show the annual average profits after interest and tax of the various technologies and their developers (in nominal terms).

Figure 6 – Annual Average Profits After Interest and Tax, £/kW

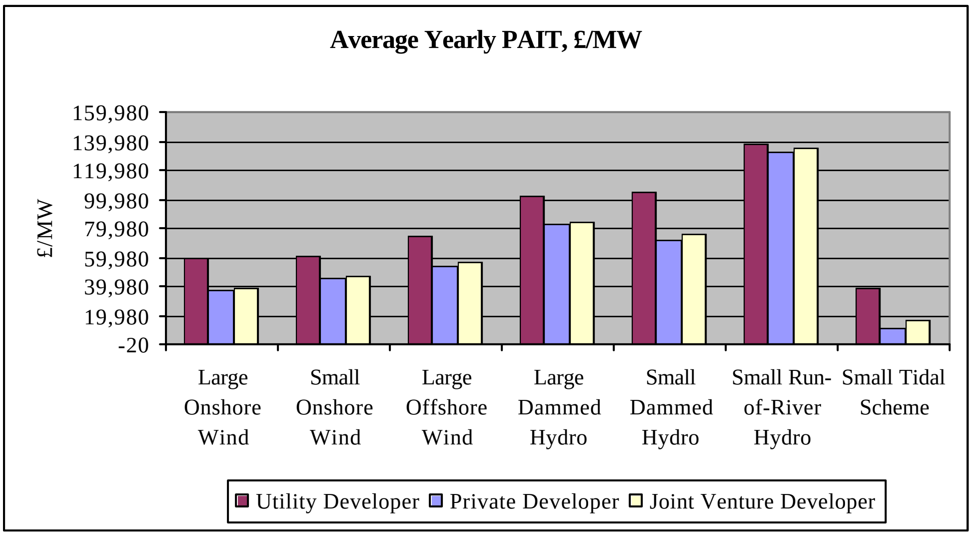
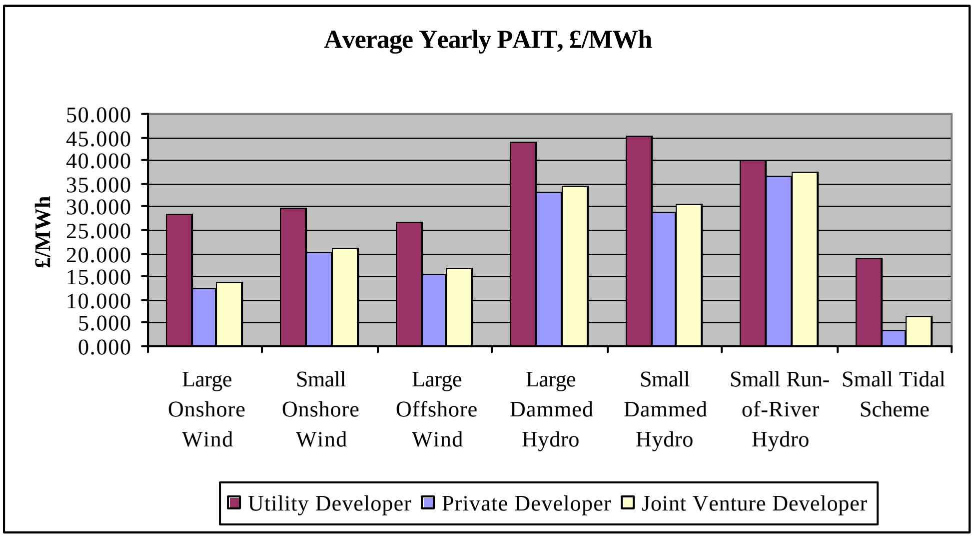


Figure 7 – Annual Average Profits After Interest and Tax, £/MWh



5.3 Sensitivity Analysis

The base cases represent a central view of the value of the projects to a developer. However, given the variable nature of the electricity markets and the substantial uncertainties around many of the parameters, particularly given the relatively long lead time for the projects, it would also be necessary to understand:

(a) Which parameters are of most significance to the project's value; and

(b) How the Base Case value could change with variations in the significant parameters.

As an illustration, we took the 40MW Onshore Wind Farm with a Utility Developer and carried out a sensitivity analysis to see which parameters had the most effect on the project economics.

5.3.1 10% Change In Key Parameters

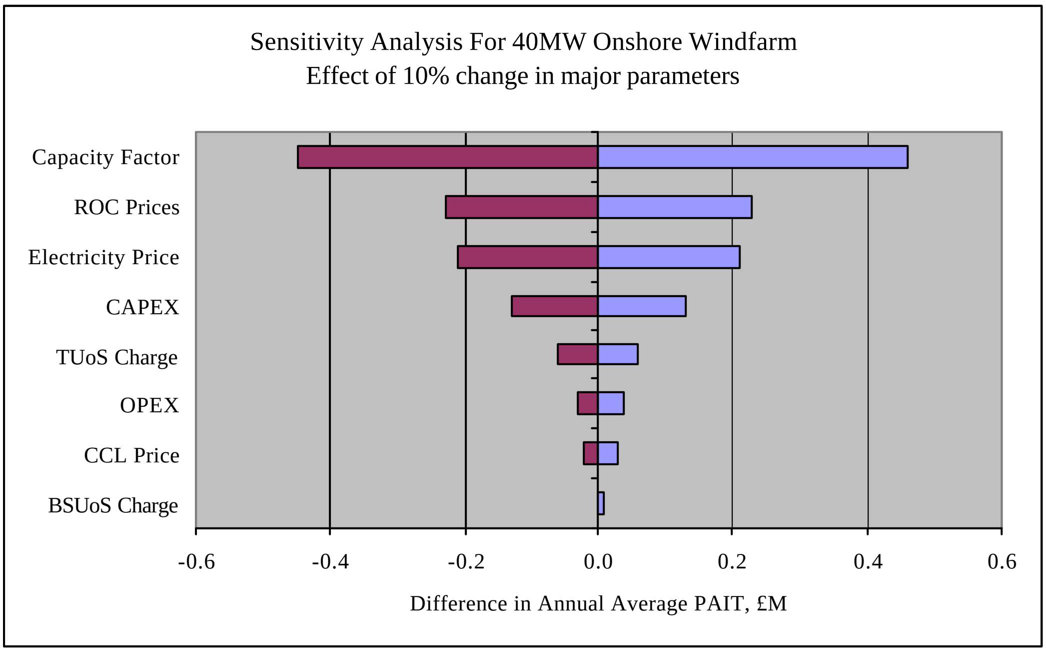
The effect on the Annual Average Profit After Interest and Tax (PAIT) of changing each of the main parameters by 10% was investigated. The parameters changed are shown in the following table, along with the corresponding change in PAIT:

Table 8 – Effect of 10% Change in Key Parameters

Parameter	Change in Annual Average PAIT, £M	Change in Annual Average PAIT, %
Capacity Factor	0.46	18.85
ROC Prices	0.23	9.43
Electricity Price	0.21	8.61
CAPEX	0.13	5.33
TUoS Charge	0.06	2.46
OPEX	0.04	1.64
CCL Price	0.03	1.23
BSUoS Charge	0.01	0.41

This is shown diagrammatically in Figure 8 below.

Figure 8 – Effect of 10% Change in Parameters For 40MW Onshore Windfarm



This shows that the factor which has the largest effect on the Annual Average PAIT is the capacity factor (in other words, the proportion of time that the plant is able to generate at full capacity). As a 10% variation in annual capacity factor is entirely possible (due to more or less windy years), it is clear that the annual revenues from an onshore windfarm project may vary considerably. Capacity factors will also vary from site to site, meaning that some windfarms will be more profitable than others, depending on their location.

5.3.2 Realistic Changes In Key Parameters

The likely *actual* variation in certain parameters may be more or less than 10%, and may not necessarily be symmetrical. It is therefore instructive to investigate the effect of the potential range of values of the main parameters has on the project economics. The range of each of the main parameters is shown in the table below, followed by a brief discussion on the rationale behind each range.

Table 9 – Ranges in Actual Values for Key Parameters

Parameter	Base Case	High Case	Low Case
Capacity Factor	30%	35%	25%
Electric ity Price	As per forecast	+10%	-20%
ROC Prices	£45/MWh to 2009, then £35/MWh to 2027	£45/MWh to 2027	£45/MWh to 2009, then £30.51/MWh to 2027
CCL Price	£3.01/MWh	£3.44/MWh	£2.58/MWh
TUoS Charge	£17.00/kW	£11.00/kW	£23.32/kW
CAPEX	£750M	£700M	£850M
OPEX	2.0% of turbine coats	1.5% of turbine costs	2.5% of turbine costs

Capacity Factor – The capacity factor of a wind farm depends on its location and the wind regime in that spot. Historic data comparing England and Wales with Scotland over the last sixteen months shows a variation in capacity factors between these large-scale regions of 2.5%. We have therefore considered a variation of ±5% to reflect the greater variation to be expected between individual sites or between smaller-scale regions.

Electricity Price – Electricity prices in Great Britain can change markedly between years, depending on many influences, including the number and type of generating stations available to meet demand and the degree of competitiveness in the market. However, over the last few years prices in the wholesale electricity market have been as low as they have ever been, reflecting an oversupply in capacity and the high degree of competitiveness in the market. However, the excess capacity in the market is decreasing, and our Base Case forecast predicts rising prices to reflect this tightening supply margin. Our High Case represents a premium on the predicted prices, which could occur if demand is higher than forecast or even more generation exits the market. Our Low Case represents a return to the lower prices of the last few years, instigated by a wave of new generation projects being built and a high degree of competitiveness in the market.

Renewable Energy Certificate Prices – Our Base Case ROC prices follow our prediction of renewable growth in Great Britain and the current Renewables Obligations in England and Wales and Scotland. Our High Case assumes that the newly announced consultation on the increase in the Renewables Obligation target to 15% in 2015 is put in place, giving the market more confidence in the longevity of the scheme. This results in longer term contracts being available at prices similar to those available now for shorter term contracts. Our Low Case assumes that many new projects are brought to fruition over the next few years and the renewable energy targets are almost met. It is our view that the renewable generators will act rationally to keep the price of ROCs from dropping below the buy-out price (currently £30.51/MWh) and so we have kept the Low Case price at that value for the period 2010 onwards.

Climate Change Levy Price – In the current market the CCL certificates are achieving around 70% of their full value (£4.30/MWh). Our High Case assumes that generators can achieve 80% of the full value. Our Low Case reflects a lower percentage of the full value (60%) being achieved, reflecting the lower range of contracts currently seen in the market.

Transmission Use of System Charge – Our Base Case TUoS charges are based on an extension of the current England and Wales TUoS charges to include Scotland. Our High Case reflects a reduction in this value to slightly higher than the current charges for the North of England and includes the removal of the "Transmission Residual Charge", which is currently the subject of consultation. Our Low Case includes the effects of several modifications to the current methodology which have recently been proposed and which would increase TUoS further.

Capital Expenditure – Our Base Case reflects the mid-range for the costs of capital expenditure reported in the public domain. The High and Low Cases reflects the lower and upper ranges for capital expenditure costs, as reported.

Operating Expenditure – Industry standard Operating and Maintenance costs lie between 1.5% and 2% of the turbine costs for onshore windfarms. In our Base Case we used the higher value, representing the potential distances to be travelled for maintenance in the North of Scotland. In this sensitivity analysis we have looked at the lower of these values and also at a further increase in the Operating Costs, to 2.5% of the turbine costs.

The results of these sensitivities are shown in the diagram below and summarised in Table 10.

Figure 9 – Effect of Likely Changes on PAIT for 40MW Onshore Windfarm

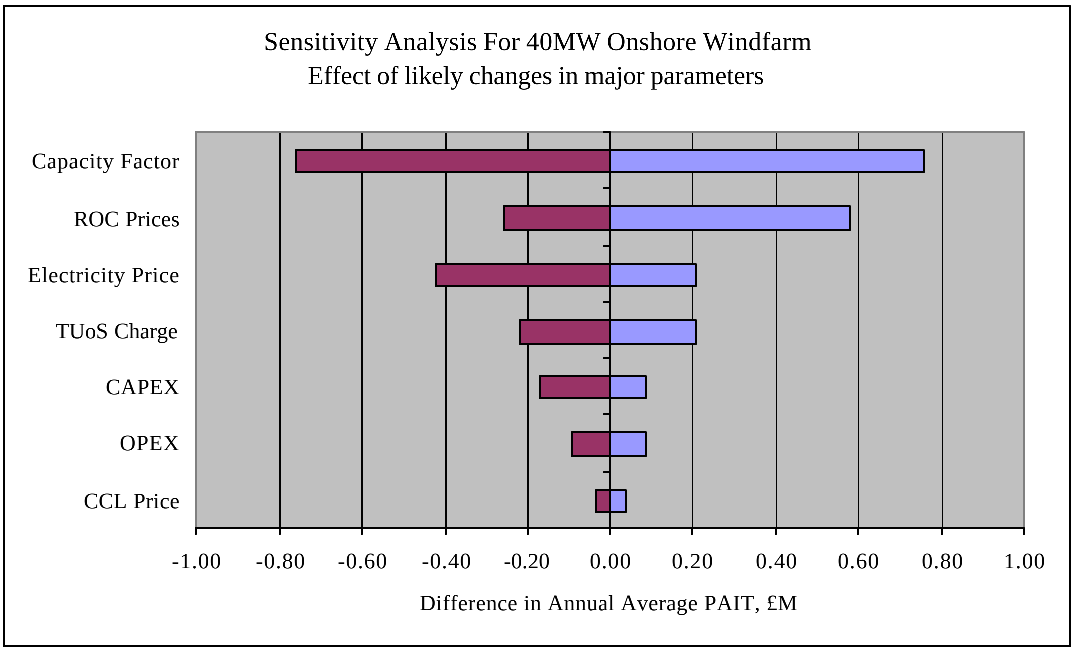


Table 10 – Effect of Likely Changes in Key Parameters

Parameter	Base Case Annual Average PAIT, £M	High Case Annual Average PAIT, £M	Low Case Annual Average PAIT, £M	Variation %
Capacity Factor	2.44	3.2	1.68	+31.1/-31.1
ROC Prices	2.44	3.02	2.18	+23.8/-10.7
Electricity Price	2.44	2.65	2.02	+8.6/-17.2
TUoS Charge	2.44	2.65	2.22	+8.6/-9
CAPEX	2.44	2.53	2.27	+3.7/-7
OPEX	2.44	2.53	2.35	+3.7/-3.7
CCL Price	2.44	2.48	2.41	+1.6/-1.2

Clearly the project is most sensitive to the potential variations in the capacity factor, giving a potential 31% change in the Annual Average PAIT. This is followed by the potential variations in the ROC and electricity prices.

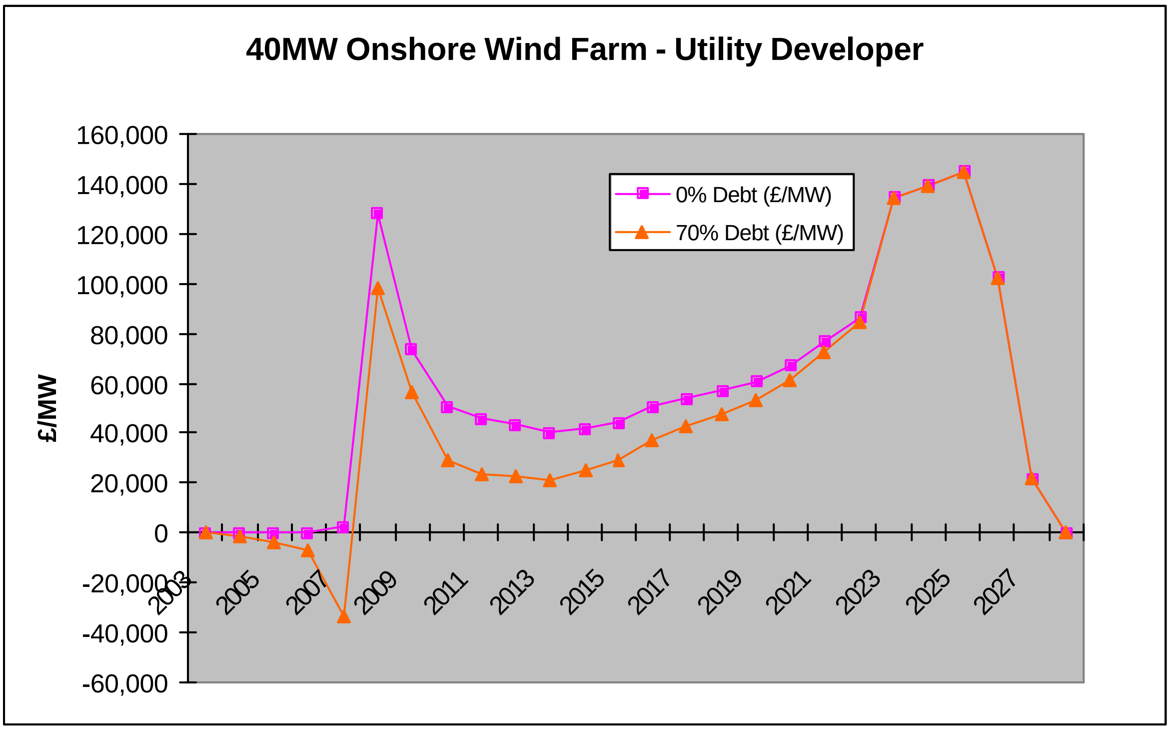
In addition to this quantitative analysis we suggested, in section 4.6, that a utility developer may look to finance a development partly by debt. We have highlighted the effects in terms of profits after interest and tax expressed in £/MW and £/MWh in the section below. We were also asked to provide a discussion of the effects on the economics of a project if it were to be commissioned before the 2007 start date assumed in the Base Case.

5.3.3 Effects of a Different Debt/Equity Ratio for a Utility Developer

Taking the small-scale onshore wind development as an example, a utility developer utilising 70% debt would receive average annual profits after interest and tax of £49,886/MW or £22.76/MWh respectively compared to the Base Case example (with zero debt) of £61,043/MW and £29.58/MWh respectively. Clearly, the amount of debt that a developer uses for financing the project will have a large impact on profits after interest and tax.

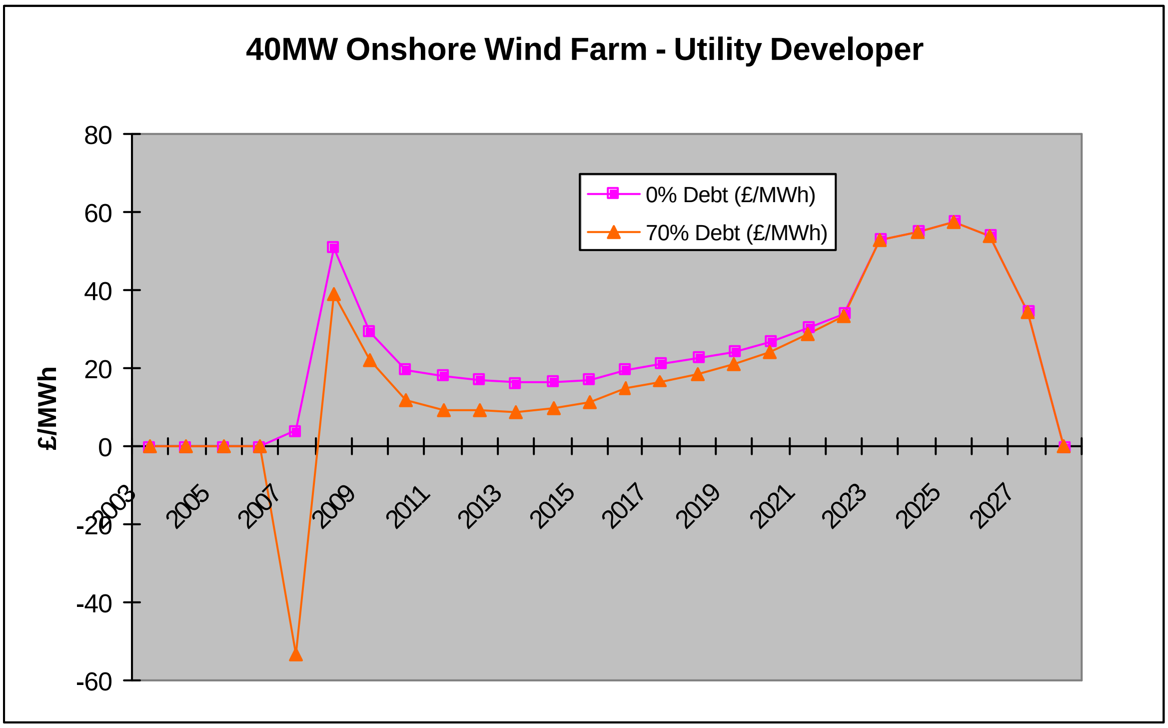
Figure 10 and Figure 11 below show the average profits after interest and tax of the 40MW onshore wind development being developed by a large utility under two debt/equity scenarios.

Figure 10 – Average Profits After Interest and Tax for a Utility Developer at Different Debt/Equity Ratios (£/MW)



The initial spike in profits shown in Figure 10 results from large tax benefits towards the start of the project due to tax relief on capital allowances on the initial investment. From about 2013 to 2022 the average profit after interest and tax for the zero debt scenario is £57,810/MW and for 70% debt is £47,281/MW (the difference being due to the debt repayment over this period). At the commencement of the project the profits after interest and tax for the debt financed project are negative due to having to pay interest before earning revenue.

Figure 11 – Average Profits After Interest and Tax for a Utility Developer at different Debt/Equity ratios (£/MWh)



5.3.4 Construction and Operation Before 2007

The start date for each of the schemes has been modelled from 2007, based on a typical lag time for project design and development and including an allowance for consultation and obtaining planning permission. This following section discusses the changes to the Base Case if a scheme was to be commissioned *before* the proposed introduction of the GB wide transmission and trading arrangements (BETTA) in April 2005.

Base Electricity Prices

Under the existing arrangements, a new generator in Scotland would have to find a buyer for its output, as with the E&W market. Both Scottish Power and Scottish and Southern Energy are obliged to provide the balancing energy requirements (which are regulated by reference to E&W market prices) of independent operators for independent generation on their respective networks. Therefore, the base electricity price would be very similar to that used in the Base Case under BETTA.

Transmission Losses

Under existing arrangements, transmission losses are apportioned wholly to electricity suppliers. Therefore, generators in Scotland are currently not exposed to transmission losses. This would improve the economics of a renewable energy project by 2%.

Connection and Transmission Use of System Charges

New generators connecting to Scottish and Southern's transmission network will pay a shallowish connection charge similar to that in the E&W market. New generators will also pay a Transmission Use of System charge. Under existing arrangements, a new generator connected anywhere on the SSE network will pay £5.44 per kW[9] of installed capacity.

In addition to the relevant TNUoS charges, generators that wish to export across the Scottish Interconnector will be liable for interconnector charges. There are currently three elements to the Interconnector charges:

- Use of system charges at the boundary with NGC;
- Capacity charges for use of the Interconnector upgrades; and
- Interconnector administration charges.

These charges amount to in the region of £20/kW[10]. Therefore a generator would see a higher charge under the existing arrangements if it were to export electricity to E&W. However, if it were to supply electricity in Scotland only it would see a lower charge under the existing arrangements[11].

Distribution Use of System Charges

As previously mentioned in section 3.4.3, generators connected to the distribution system currently pay a deep connection charge – that is the total cost of connection plus any reinforcement works required to facilitate the new generation. Depending on the amount of reinforcement required these costs could be significantly higher than a shallower connection policy that is proposed under BETTA.

Market-Related Charges

There is currently no wholesale market in Scotland. Therefore the market related charges, BSUoS, RCRC and BSCCo costs, that will be seen under BETTA are currently not applicable. This would amount to a reduction in the Base Case model of £0.69/MWh.

Embedded Benefits

There are currently no transparent embedded benefits available for ELEGs connected to the distribution networks in Scotland, although in certain cases demand TNUoS may be negotiated. This is because the charges that constitute embedded benefits are not applied in Scotland.

The overall effect of starting a project before 2007 would be broadly positive but would depend on the conditions negotiated with SSE and SP for connection to the electricity grid and whether a contract for the supply of electricity was to customers in Scotland or E&W.

[9] A new generator connected to the Scottish Power network will pay a site specific use of system charge.
[10] Plus NGC generation TNUoS charge and a Scotland demand TNUoS charge.
[11] BETTA TNUoS charge of £17/kW

6. PROJECT RISKS

In this section we discuss the generic risks associated with the development of renewable energy schemes.

6.1 Generic Risks

The generic risks applicable to any renewable energy project include:

- Planning Risk;
- Performance Risk;
- Availability of resource – 'Volume Risk';
- Sustainability of the Renewables Obligation – 'RO Risk';
- Electricity/ROC price risk; and
- Offtaking Agreements – 'PPA Risk'.

Of particular significance to renewable projects is the risk of sustained reductions in wind speed, rainfall, electricity and ROC prices. On the other hand, increases in any of these parameters could substantially increase project returns. It is for the communities to decide whether they are prepared to take any exposure to these potential upsides and downsides in the structure of any contract they may put in place with the developer/operator of a scheme.

Planning Risk
Potential renewable energy developments progressing through the planning phase have the risk of being rejected for a variety of reasons, including:

- Visual intrusion;
- Cumulative impact; and
- MOD/radar interference.

Although objections on these grounds can sometimes be overcome by a reworking of the project plans, many projects do not get past the planning stage. This is a risk with all developments – in Scotland about 10% of renewable energy planning applications are refused, compared with around 50% in England.[12]

The costs involved in pre-development can vary according to technology (likely to be highest for onshore wind and lowest for run-of-river hydro), and according to the characteristics of the individual site. A developer of a typical 40 MW onshore wind farm could expect to pay up to £250,000 in pre-development costs (see Annex G). Taking into account a 10% failure rate, they would a budget of around £278,000 to achieve a viable project, which would then cost a further £33 million in capital expenditure.[13] At this stage, pre-development costs would be regarded as 'sunk costs' and therefore not taken into account. Pre-development expenditure is generally funded from the developer's own balance sheet. Therefore it is taken into account in a general sense via the discount rates for each developer. A developer will use a discount rate that is appropriate for a project of that type, which would take into account all of the risks involved, including planning risk.

[12] Source: BWEA, 2003
[13] £250,000 divided by the probability of success (90%).

Performance Risk

The performance of the technology (whether it is proven, such as onshore wind and hydro, or more experimental, such as offshore wind and wave/tidal) will affect an investor's view of the risk and therefore returns on an investment. This has been taken into account in our use of different discount rates for each technology, but they are ultimately subjective and will vary according to the investor. In addition, investors will look at the project team to asses the risk of failures of performance in project management, financial management, and operation and management.

Availability of resource – 'Volume Risk'
In the analysis this is represented by the load factors for each of the technologies. For example onshore wind has a load factor of around 30%, indicating that power is only produced 30% of the time throughout the year (i.e. when the wind blows). However, these are average load factors for the technologies and not site specific. The resource may be greater or less than the figures quoted and can vary year on year. When developing a project a developer will measure the resource of the site before committing to the construction of the project. This can take anywhere from 6 months to 2 years. This does not, however, protect the developer from the unpredictable nature of the weather in the long term, such as long periods of no rain or no wind.

Sustainability of the Renewables Obligation – 'RO Risk'
The viability of many renewable projects is dependent on the extra income received via the Renewables Obligation. As the RO is a government initiative it is possible that a change in government, or government policy, could radically change the Obligation or, indeed, possibly get rid of it altogether. However, given the current Government's commitment to reducing greenhouse gas emissions it is unlikely that there will be any major changes to the Obligation in the near future. Indeed, the Government has pledged an 'aspiration' to increase the level of the obligation from 10% in 2010 to 20% in 2020.

Electricity/ROC prices – 'Price Risk'
'Price risk' is the fluctuation in income to the project as a result of movements in electricity and/or ROC prices. The primary driver for both electricity and ROC prices is the demand/supply balance on the system. Assuming a properly functioning market, because of the timescale for the construction of generating capacity, the variation in project income as a result of price fluctuations year on year is likely to be less marked than the volume variations. However, over the course of the project, there is a higher probability that average prices will vary from those forecast.

Price risk can be managed to some extent. The prime concern for renewable developers is to secure a long term guaranteed price, to give proposed projects bankability and secure finance. For this reason developers look to negotiate PPAs on as long a time scale as possible. One option is to 'lock-in' energy and ROC prices under fixed-price sales contracts.

Because of concerns about risk in the renewable energy market, developers are likely to be cautious about offering unsustainable community benefit payments that may be affordable at the start of the project but not necessarily over the full 20 year lifetime of a project. PPAs for renewable energy projects can range from as little as five years to around fifteen years, and the length of the PPA should be taken into account in negotiations over community benefits.

The susceptibility of the market to price risk was illustrated recently. The market price for ROCs dropped by around £3/MWh after the DTI announced that TXU and Maverick Energy, both in administration, owed £23.6 million to the ROC buy out fund (which would normally be redistributed to compliant suppliers). In addition, long term contracts for ROCs are currently said to be heavily discounted due to uncertainty over the future of the Obligation post 2010. It is still too early to tell what the effect of the recent announcements regarding an extension of the Obligation to 2015 has been in the market.

Off-taking Agreements – 'PPA Risk'
In the modelling of the Base Case we have assumed that the developer is able to sell all of its output to either an electricity supplier or electricity trader. Therefore when sufficient resources are available the generator will be able to generate electricity and sell its output. However, in reality there be a risk that a developer may not be able to sell all of its output and so not be able to fully realise the benefits of the development.

Due to the Renewables Obligation the demand for renewable energy in the short to medium term will be high. However, as more and more renewable developments come on line buyers of renewable power may start to cherry pick the best developments, i.e. those with the most predictable resources. Those developments with less predictability may then receive lower prices or may not even be able to sell their output.

There have been a number of high profile electricity suppliers going insolvent in the past few years. A renewable generator in a long-term power purchase agreement with such a supplier may not be able to get such a good deal with another supplier or trader. They may also have to sell their output on the open market if they are unable to find a buyer, and would then be prone to the risks of selling in the open market, such as imbalance charges.

7. COMMUNITY BENEFITS

7.1 Overview

The aim of this report has been to provide the Councils with an understanding of the economics of renewable energy developments. The examples provided here have of necessity been generalised and based on information in the public domain. Therefore it must be recognised that in practice, individual projects will differ from the examples given here, due to a combination of site-specific technical variations, and the individual financial and organisational circumstances of each particular developer, much of which will be confidential information.

For this reason, combined with the fact that the profitability of projects varies widely between technologies, and financial viability depends further on the required rates of return of different kinds of investors, we recommend that any community benefits should be negotiated with developers on a site-specific basis. We believe that it is important that all parties to the negotiation should understand the economics of renewable energy and the effect of any community benefit requirement on project cash flows and financial viability. This is more likely to lead to 'win-win' outcomes, where the financial impact on the developer of providing community benefits is minimised, and the material benefit to the community is maximised.

7.2 Community benefits in theory and practice

In theory, the rationale for any renewable energy development to provide community benefits is simply that it utilises a communal resource: the wind, sun, waves and tides are all 'public goods' which are not 'owned' by the developer. Other communal resources may also be 'used up' or otherwise affected by a development – this can include communal land, views, rights of way, even some measure of 'peace and quiet'. In theory, therefore, the appropriate level of community benefits would be linked to the impact of the development on all of these communal resources. Local authorities are in a good position to represent the various interests of the community, which may be affected in different ways by a development.

However, such impacts are extremely difficult to measure, and equally difficult to convert into financial terms. Therefore while an appropriate starting point for negotiations is the environmental assessment made during the planning process, in practical terms it is also necessary for local authorities to understand the developer's 'walk-away' price: the level of community benefits at which the project would become uneconomic and would therefore be abandoned. In addition to this, local authorities need to consider longer-term and wider implications: for example, an apparent 'success' for the community in negotiating a high level of benefits at one location may lead to fewer applications for projects in other locations, and therefore lower community benefits overall. A successful approach to community benefits requires careful balancing of the short- and long-term interests of developers and the community.

Clearly, if a project would become uneconomic due to providing community benefits, it would not be built, and all benefits would be lost. The maximum potential community benefit is therefore likely to be equal to the difference between the NPV of the project at one particular location, and the NPV of the project at an alternative location where community benefits would not apply. Given a wide range of alternative locations for renewable energy projects, it is likely that a high community benefit requirement in one area would be 'undercut' by lower requirements in other, perhaps otherwise less favourable, areas. This would tend to drive the realisable community benefits down to a minimum level.

However, there is not necessarily a wide range of alternative locations available in the UK for most renewable energy technologies, and as more sites are used up, the most attractive remaining sites will be increasingly valuable. For example, larger hydro projects are limited to very few sites in the UK and therefore there are fewer alternatives than there may be for a wind farm. Therefore the community may be in a stronger negotiating position with respect to a large hydro project than might be the case for a wind farm.

7.3 Differences in value between locations

In section 5.3 above we discussed the sensitivity of renewable energy project economics to various input factors, identifying the capacity factor, ROC price and electricity price as the three most important factors. The ROC price is determined nationally, and while the electricity price does have a locational component, it is relatively small and can be ignored for the purposes of comparing two potential projects in nearby locations. Therefore the factor that remains with the greatest influence on project economics is the capacity factor. This in turn is primarily dependent on the resource availability.

For example, while the Net Present Value of a typical small wind farm operating at a capacity factor of 30% has been estimated at around £229,000/MW, the NPV of the same farm at a windier site enabling a 35% capacity factor would be over £388,000/MW. This means that sites with the best resources will be valued at a premium and there may be more potential to negotiate higher rates of community benefits for developments on these sites.

The cost of connecting to the grid, and of building roads and other infrastructure, is also potentially a major factor affecting the economics of a project. Our models have assumed connections at sites relatively near to the grid and existing road infrastructure, and that major upgrades to the network are either not required, or are not charged to the developer (under a 'shallowish' connection policy). However, over time such sites may become scarce, and this would increase the relative value of sites with good infrastructure.

An upgrade of grid or road infrastructure may be required to make a project viable. Further improvements in necessary infrastructure may cost less to the developer (as an incremental cost) than the equivalent improvements would have cost, if undertaken as a separate project. Therefore one option to maximise the value of a community benefit at least cost to the developer may be to negotiate a benefit in the form of additional infrastructure improvements, for example an upgrade to the electricity grid or a road improvement. Similarly, a local manufacturing base that would provide spin-off benefits to the community in the form of employment may also be in the developer's longer-term interest in terms of reducing costs.

Finally, it is noted that developers are likely to be cautious about offering unsustainable community benefit payments that may be affordable at the start of the project but not necessarily over the full 20 year lifetime of a project. Power Purchase Agreements for renewable energy projects typically range from five to fifteen years, and the length of the Agreement should be taken into account in any negotiations over community benefits.

GLOSSARY

BETTA	British Electricity Transmission and Trading Arrangements
BSC	Balancing and Settlement Code
BSCCo	Balancing and Settlement Code Company
BSUoS	Balancing Services Use of System (charges)
BWEA	British Wind Energy Association
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCL	Climate Change Levy
CMRS	Central Meter Registration Service
CHP	Combined Heat and Power
DSCR	Debt Service Cover Ratio
DTI	Department of Trade and Industry
DUoS	Distribution Use of System charge
ELEG	Embedded Licence Exempt Generator
EU	European Union
E&W	England and Wales
GB	Great Britain
GSP	Grid Supply Point
GW	Gigawatt
GWh	Gigawatt hour
IRR	Internal Rate of Return
kW	Kilo watt
kWh	Kilo watt hour
LEC	Levy Exemption Certificate
MCT	Marine Current Turbines
MW	Megawatt
MWh	Megawatt hour
NETA	New Electricity Trading Arrangements
NGC	National Grid Transco
NPV	Net Present Value
Ofgem	Office of Gas and Electricity Markets
OPEX	Operational Expenditure

OTC	Over the counter
OWC	Oscillating Water Column
PAIT	Profit After Interest and Tax
PBIT	Profit Before Interest and Tax
RCRC	Residual Cash flow Reallocation Cash flow
RO	Renewables Obligation
ROC	Renewables Obligation Certificate
SSE	Scottish and Southern Energy
TNUoS	Transmission Network Use of System (charges)