Energy Policy 39 (2011) 23–39

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Levelised costs of Wave and Tidal energy in the UK: Cost competitiveness and the importance of "banded" Renewables Obligation Certificates

Grant Allan [a,*], Michelle Gilmartin [a], Peter McGregor [a], Kim Swales [b]

[a] Fraser of Allander Institute, Department of Economics, University of Strathclyde, UK
[b] Department of Economics, University of Strathclyde, UK

ARTICLE INFO

Article history:
Received 3 March 2009
Accepted 17 August 2010
Available online 8 October 2010

Keywords:
Levelised costs comparison
Marine energy
Support mechanisms

ABSTRACT

In this paper, publicly available cost data are used to calculate the private levelised costs of two marine energy technologies for UK electricity generation: Wave and Tidal Stream power. These estimates are compared to those for ten other electricity generation technologies whose costs were identified by the UK Government (DTI, 2006). Under plausible assumptions for costs and performance, point estimates of the levelised costs of Wave and Tidal Stream generation are £190 and £81/MWh, respectively. Sensitivity analysis shows how these relative private levelised costs calculations are affected by variation in key parameters, specifically the assumed capital costs, fuel costs and the discount rate. We also consider the impact of the introduction of technology-differentiated financial support for renewable energy on the cost competitiveness of Wave and Tidal Stream power. Further, we compare the impact of the current UK government support level to the more generous degree of assistance for marine technologies that is proposed by the Scottish government.

1. Introduction

Levelised costs are the "ratio of total lifetime expenses versus total expected outputs, expressed in terms of the present value equivalent" (Nuclear Energy Agency and International Energy Agency, 2005). They form the basis of much of the discussion in policy circles over the costs of different technologies for electricity generation and have been estimated frequently over the last twenty-five years (Nuclear Energy Agency, 1983, 1986; Nuclear Energy Agency and International Energy Agency, 1989, 1998, 2005). Similar studies have also been undertaken for a number of individual technologies, e.g. energy crops (Styles and Jones, 2007), integrated solar combined cycle power plants (Horn et al., 2004), and coal-fired and liquefied natural gas combined cycle power plants (Jeong et al., 2008). Further, there are studies that make comparisons across technologies and methodologies (Kammen and Pacca, 2004; Roth and Ambs, 2004).

In this paper, we calculate levelised costs for two marine energy technologies: Wave and Tidal Stream power. The costs are estimated on a consistent basis with other renewable and non-renewable generation technologies. All costs considered are those that would be paid by the owner of the electricity generation technology. We label these "private" costs. Our calculations are made using the cost breakdown given in the UK Government's study of the levelised costs of ten electricity generation technologies (DTI, 2006) and cost data estimated on a comparable basis for Wave and Tidal Stream generation, neither of which was included in the original DTI study. The figures for Wave and Tidal Stream costs are taken from existing literature on these technologies. The private levelised costs of generation for all twelve technologies are then calculated in a common and standard manner. We follow the method used by the Carbon Trust (2006) in their estimates of the costs of Wave and Tidal Stream energy, but extend this work in a number of ways.

This study is necessary for two reasons. First, estimates of levelised costs are extensively used as benchmarks for the economic viability of different electricity generation technologies. They are published regularly by the International Energy Agency and the US Department of Energy and are widely reported in the energy policy literature (Gross et al., 2007). However, no UK study exists that compares conventional electricity generation technologies with Wave and Tidal Stream technologies separately.[1] Secondly, electricity produced by renewable technologies is typically more expensive than "conventional" forms of generation, and so renewable electricity is generally subsidised. In the UK this occurs through the Renewables Obligation (RO) where

[1] Ernst and Young (2007) compare the cost of wave and tidal against other renewable technologies, but not against non-renewable technologies, while Royal Academy of Engineering (2004) do not separately identify wave and tidal technologies in their study, but group these together as "marine".

* Corresponding author. Tel.: +44 141 548 3838; fax: +44 141 548 5776.
E-mail address: grant.j.allan@strath.ac.uk (G. Allan).

0301-4215/$ - see front matter © 2010 Elsevier Ltd. All rights reserved.
doi:10.1016/j.enpol.2010.08.029

operators of accredited renewable electricity facilities receive Renewables Obligation Certificates (ROCs) for each MWh of electricity they produce. Aspects of the RO have changed in recent years, reflecting the evolving nature of the renewable energy industry in the UK. In particular, the focus of the RO is no longer technology neutral. "Banded" ROCs provide different support levels for different types of renewable electricity generation, such that newer, and typically more costly, renewable technologies are granted a higher level of support. Further, there are plans in Scotland to introduce higher banding levels for some renewables, specifically marine technologies, than those provided for the same technologies in the rest of the UK (BERR, 2008a; Scottish Government, 2008). Policy discussions regarding the "correct" support level for each technology requires detailed knowledge of the current costs of generation for alternative renewable technologies.[2]

The results of our analysis provide important insights about the cost competitiveness of Wave and Tidal Stream generation in the UK. Government policy interventions, and the growth in installed and tested marine energy devices as a result of government initiatives (along with the valuable support of organisations such as the European Marine Energy Centre in the UK), are ultimately intended to lead to widespread commercial deployment of marine energy in the UK, and place the UK at the forefront of marine energy development across the world.[3] Knowledge of the extent to which Wave and Tidal Stream technologies are economically competitive in the UK will be an important indicator of the cost competitiveness of the technologies in other countries. This, in turn, will be a crucial factor in determining the successful commercial development of the world marine sector as a whole.

The paper proceeds as follows. In Section 2 we detail the levelised costs method and describe the costs used by DTI (2006) in calculating levelised costs for ten technologies.[4] In Section 3 we describe the data used to calculate levelised costs of Wave and Tidal Stream energy technologies, and present point estimates of their levelised costs. In Section 4, we conduct an extensive sensitivity analysis on construction costs, fuels costs and the discount rate. In Section 5 we explore the impact of the introduction of additional support to Wave and Tidal Stream technologies through "banding" or multiple ROCs. We present a brief discussion of our results in Section 6 and our concluding comments in Section 7.

2. Levelised costs: method, assumptions and results

2.1. Method

Levelised costs estimates for electricity generation technologies have been calculated widely: they provide both a measure by which the relative cost competitiveness of technologies can be compared and a transparent method to show how key factors affect the costs of different technologies. The Nuclear Energy Agency and International Energy Agency (NEA/IEA) (2005, p. 11) states, for instance, that the purpose of their study is to "serve as a resource for policymakers and industry professionals seeking to better understand generation costs". A standardised method for estimating levelised costs is "a prerequisite for a fair comparison" (NEA/IEA, 2005, p. 173) between the technologies being considered.

The levelised costs reported for each technology is the cost of a unit of electricity generation supplied to the existing electricity network and is appropriate for comparing single generation units. Note, however, that this does not typically take account of the full system costs of the unit on the grid (NEA/IEA, 2005). Costs that are normally included cover investment costs (i.e. construction costs), operations and maintenance costs and fuel expenditures. The NEA/IEA report, for instance, attempts to capture only the costs that would be borne by the electricity producer and affect their choice of generation technology.

Other costs might be included in a levelised cost analysis (Kammen and Pacca, 2004). The report by the Royal Academy of Engineering (RAE, 2004), for instance, includes the cost of standby generation and the calculations made in PB Power (2006) also incorporate the costs of "system integration" and "carbon emissions".[5] It should be noted however that even in the reports that include these additional costs, the costs of capital, fuel and operation and maintenance constitute by far the greatest part of the estimated levelised costs.

The additional cost to the system for the provision of "capacity to ensure system reliability" might also be included (Skea et al., 2008). This is separate from the short-term system balancing impacts included in PB Power (2006) as "system integration" costs. This system reliability cost is likely to be significant for "intermittent" generation. Such (renewable) installed capacity could have low "capacity credit" and so would not significantly displace conventional thermal plant capacity required to maintain system reliability (as measured, for instance, by Loss of Load Probability (LOLP)). However, all of the additional costs discussed here relating to pollution, system balancing and system reliability/standby generation costs would be externalities to the private costs incurred by the developers. They are therefore not included in the private levelised costs discussed in this paper.

There are two methods commonly used to calculate the levelised costs (Gross et al., 2007): the "discounting" method, and the "annuitising" method. In the discounting method, shown in Eq. (1), the stream of (real) future costs and (electrical) outputs, identified as C_t and O_t in period t, are discounted back to a present value (PV). The PV of costs is then divided by the PV of lifetime output. The levelised costs measure under the "discounting" method, LC_D, is given as

$$LC_D = \frac{PV(Costs)}{PV(Output)} = \frac{\sum_{t=0}^{n} C_t/(1+r)^t}{\sum_{t=0}^{n} O_t/(1+r)^t} \qquad (1)$$

[2] We note that in this paper we do not consider projections of the costs of generating electricity from wave and tidal technologies. We are however able to consider the scale of cost reductions for wave and tidal which are necessary for such technologies to become "competitive" compared to other renewable and non-renewable technologies.

[3] In fact the Scottish Government explicitly identifies renewable energy as being a key sector for assisting regional economic development. Allan et al. (2008) examine the potential economic and environmental impact of developments of a renewable energy technology on a regional economy.

[4] The ten technologies are the following: Pressurised Water Reactor (PWR) Nuclear, Combined Cycle Gas Turbine (CCGT) (with and without Carbon Capture and Storage (CCS)), Pulverised Fuel (Advanced Super Critical) (with and without CCS), Integrated Gasification Combined Cycle (IGCC) Coal (with and without CCS), Retrofit Coal (based on Pulverised Fuel (ASC) with Flue Gas Desulphurisation and CCS, and On- and Offshore Wind. All these technologies (barring those with CCS) are those which are being commercially deployed. CCS technology has not been deployed on a large scale, but is an emerging technology in development worldwide.

[5] PB Power (2006) report that "the range of additional system costs arising from connection of significant wind generation into the GB transmission systems falls between ~0.03 and ~0.3 p/kWh when the costs are spread across all electricity consumption in the GB market". It would be useful to compare these figures to those presented in the UKERC TPA report on the impacts of intermittency (Gross et al., 2006). PB Power assumed a cost of carbon emissions was 17.72 £/Tonne of CO_2 emissions, for coal and CCGT gas plants (but not Open Cycle Gas Turbine technology). For future research, we note that in PB Power (2006) "system integration" costs was not applied to Tidal generation, perhaps given its more predictable nature.

This method is used by the Nuclear Energy Agency and International Energy Agency (2005) in their joint reports on the costs of electricity generation and by the Carbon Trust (2006) in its report on marine energy.

In the "annuitizing" method, shown in Eq. (2), the present value of the stream of costs over the device's lifetime (including pre-development, construction, operation, and any decommissioning costs) is calculated and then converted to an equivalent annual cost, using a standard annuity formula. This equivalent annual cost is then divided by the average annual electrical output over the lifetime of the plant (Gross et al., 2007)

$$LC_A = \frac{Ann(Costs)}{Ave(Output)} = \frac{\left(\sum_{t=0}^{n} C_t/(1+r)^t\right) \times (r/(1-(1+r)^{-n}))}{\left(\sum_{t=1}^{n} O_t\right)/n} \tag{2}$$

This is the method used for construction costs in DTI (2006).

The discounting of (non-financial) outputs is a controversial issue. For example, there is a considerable health economics literature on the appropriate rate for discounting measured health benefits as against the rate for discounting the costs of health care programmes (Olsen, 1993). Similar arguments are made in the environmental literature (Heal, 2007).[6] However, Eq. (1) is our favoured expression.

Gross et al. (2007) state that these two methods, discounting and annuitising, give the same levelised costs when the rate (r) used for discounting costs and output in Eq. (1) is the same as that used in calculating the annuity factor in Eq. (2). However, as demonstrated in Appendix 1, for levelised costs to be the same under both measures, *annual* output must also be constant over the lifetime of the device. The annuity method converts the costs to a constant (equal) flow over time. This is appropriate where the flow of output is constant. It is commonly assumed in the literature on levelised cost estimates (Gross et al., 2007) that annual output is constant, however, the annual output of renewable technologies would typically vary from period to period (day-to-day, month-to-month and year-to-year) due to variations in the renewable resource and any outages and/or maintenance.[7]

A further feature of most levelised cost studies is that they make no attempt to deal with likely changes in input prices over time (an exception is NEA/IEA, 2005). For instance, real wages and fuel costs might be expected to increase into the future. These cost changes can be incorporated within the levelised cost framework by assuming, for instance, some evolution of real costs over time. Sensitivity analysis, on the other hand, could be used to take an informed range of possible values for key factors and show the impact on levelised costs of significant changes in these. The sensitivity analysis approach may be well suited for particular components, for instance, construction costs, where known costs may lie within a range, but commercial confidentiality prevents the likely cost to the private developer becoming public knowledge.

2.2. Levelised costs: assumptions and results

The discounting method (Eq. (1)) is used to estimate levelised costs for ten electricity generation technologies using cost data from DTI (2006). In Section 3 we apply the same method to estimate levelised costs for Wave and Tidal Stream electricity generation technologies. Note that in the analysis that follows, all costs and electrical outputs are discounted back to a (2006) present value. We follow the literature (Gross et al., 2007) in assuming, for simplicity, that output is constant in each year for which the device is operational.[8] For non-marine technologies, the specific assumptions made in the calculation of comparable levelised costs are detailed in the remainder of this section. Section 3 performs the same task for marine (Wave and Tidal Stream) electricity generation technologies.

To calculate the levelised costs of electricity generation we need the levels and timing of all costs and electrical output (e.g. in MWh) over the entire lifetime of the project. The specific elements of costs that are considered can vary across studies, so that simple comparisons of the £/MWh figures might be misleading. For example, the Carbon Trust (2006) study of Wave and Tidal electricity generation technologies employs different methods and assumptions to those used in the DTI (2006) report on ten non-marine electricity generation technologies.[9]

In this paper we calculate the levelised costs using the same categories of "private" costs for the ten non-marine technologies considered by DTI (2006). These cover costs to the builder, owner and operator of the electricity generation capacity, though we do not include "interest on borrowing". However, we follow the IEA/NEA (various years) and the Carbon Trust (2006) in adopting the discounting method to calculating levelised costs, as the annuitizing method used in DTI (2006) is less transparent. These changes mean that our estimates of the levelised costs for the ten non-marine technologies are (very) slightly different to those published in DTI (2006). But the Wave and Tidal Stream levelised costs we report can thus be compared with confidence to other electricity generation technologies. The private cost components we consider are:

- Pre-development costs (PD), which includes the cost of site selection, environmental impact assessment (EIA) and any public enquiry, if appropriate.
- Construction costs (CO).[10]
- Fuel costs (FC) including fuel delivery costs.
- Fixed operations and maintenance costs (FOM) linked to the capacity of the development.
- Variable operations and maintenance costs (VOM) linked to output (MWh) of the technology.
- Decommissioning and waste costs (DW).[11]

[6] We leave this issue for a later paper however, but note that in a Cost–Benefit Analysis of electricity generation technologies the quantity of outputs would be converted into monetary flows and would then be discounted at a common rate to the other financial variables.

[7] We include levelised cost calculations using both the discounted and annuitized methods (Appendix 1) in order explicitly to demonstrate that annual output must also be constant over the lifetime of the device for these methods to both yield the same result. The illustration of this point raises an important issue, since, in practice, annual output is likely to vary, and the degree of variability may differ across alternative technologies. The output of tidal stream devices, for instance, would normally be expected to have a predictably smaller variation in annual output than wave energy devices. The difference in levelised cost estimates under alternative approaches where annual electrical output is variable has not yet been recognised or explored in the literature and provides an avenue for future research.

[8] However, see footnote 7 for a discussion of this assumption.

[9] Indeed, it is unclear whether the same method and assumptions were employed for each technology considered in the Carbon Trust (2006). The devices were considered by 'independent assessors' and no details of the assessment methods or the unit costs were published for commercial reasons.

[10] DTI (2006) assume that there are "infrastructure costs" which only apply to the Onshore wind technology, i.e. not Offshore wind, or any other of the technologies considered. These additional costs to Onshore wind are included in our calculations. In this way, the costs presented there, and in this paper, are "energy resource to network costs", and do not include the additional costs of network infrastructure necessary to extract electricity from a specific location. One possible research extension would be to investigate how each element of costs (as well as the outputs) might vary by location. These issues are not typically captured in standard levelised cost comparisons and so are not developed further in this paper.

[11] This element is assumed in DTI (2006) to apply only to PWR Nuclear power. DTI (2006) assume that post-operation decommissioning and waste costs are met by the operator making a fixed annual payment over the lifetime of the operation

Table 1 shows the key assumptions used in order to calculate levelised costs for these ten technologies. In Section 4, we explore the impact on the estimated levelised costs of adjusting some of these key assumptions. In the notes to this table, we identify the assumptions on which calculated elements of estimates are based.

Table 2 shows how the levelised costs (£/MWh) for each of these ten technologies are calculated from the total costs for each of the cost components considered in Table 1. Each element is discounted to its present (2006 price) value using a common discount rate, *r*, of 10%, which is the rate assumed in DTI (2006). As mentioned above, we assume that annual (electrical) output is fixed over each year of the lifetime of each technology.

With the assumptions reported in Table 1, the technology with the lowest standalone levelised cost is Pulverised Fuel at £26.19/MWh, while the most expensive non-renewable method of generation is CCGT with CCS at £48.07/MWh. The levelised costs of On- and Offshore wind are £54.42 and £81.56/MWh, respectively. Whilst these point estimates are based on the best estimates of the component parts, each of these components may be subject to error or revision. We now turn to estimating levelised cost estimates for Wave and Tidal Stream devices in the UK.

3. Wave and Tidal Stream levelised costs: assumptions and results

The cost structures for Wave and Tidal Stream electricity generation technologies are, like the wind technologies in Tables 1 and 2, simpler than those of other non-renewable generation methods. As with On- and Offshore Wind, the costs of marine technologies are heavily dominated by the initial construction costs. Construction work for both Wave and Tidal Stream projects occurs evenly in 2011 and 2012, and both technologies are operational for twenty years, as assumed in Allan et al. (2008) for wave energy, and DTI (2006) for both On- and Offshore wind.

We follow the assumptions for Offshore wind in DTI (2006) and base our analysis on a Wave farm and a Tidal Stream farm, where both have a 100 MW installed capacity. Costs are converted to 2006 prices in all cases to adjust for price inflation between the years to which monetary values relate and 2006. The construction costs are crucial for the levelised costs of Wave and Tidal Stream generation technologies, and we return to this point in Section 3.1. On the other hand, fuel costs are irrelevant for renewable technologies. As with the two wind generation technologies, we assume that the costs of Operations and Maintenance (OM) for Wave and Tidal Stream are met through fixed contracts, with costs linked to installed capacity (£/kW).[12] The other key assumptions relate to the construction cost and the energy generation potential of the technology. We assume that there are pre-development costs which, given the obvious uncertainty about these costs, we assume are the same for Wave and Tidal Stream technologies as for Offshore wind, whose costs are estimated in DTI (2006).

As with On- and Offshore Wind, we would expect that construction costs will be important for Wave and Tidal Stream estimated levelised costs. We seek figures for the construction costs for first production models for these two technology types and describe how we estimate these in Sections 3.1.1 and 3.1.2 below. Construction costs are expected to be significantly lower for first production than for earlier, first prototype, models (Carbon Trust, 2006). Financial restrictions at the early development stage may mean that bespoke solutions are not possible for prototype models, necessitating the use of "off-the-shelf" units. This is unlikely to be optimal for further development, which will require additional investment. Also, the limited experience of contractors in working with marine energy devices means that a higher cost is paid to reflect the higher perceived risks. Finally, small-scale prototypes mean that cost reductions that might be achievable through scale economies are not exploited. We return to the issue of learning-induced reductions in costs in Section 4.1.

3.1. Construction costs

3.1.1. Construction costs for electricity generation from wave technologies

For Wave technologies the Carbon Trust (2006) report construction cost figures for first production models of between £1700/kW and £4300/kW. Our figure of £3622/kW for Wave lies towards the upper end of this range. The estimate is taken from recent work that examines the regional impact of the development of the Wave energy sector in Scotland (Allan et al., 2008).[13] The figures are based on an articulated attenuator-type Wave energy device (Previsic et al., 2004; Boehme et al., 2006). The cost estimates in the present paper convert these figures from 2000 prices to the 2006 base used by DTI (2006).[14] The construction

(*footnote continued*)
of the facility, which is deposited into an interest-earning fund which is able to finance these costs. In the levelised costs presented for PWR Nuclear, there are decommissioning costs of £400/kW per year for 25 years after the plant ceases operation, a total cost (in 2006 prices) of £636.0 million. Waste costs are made in the year immediately after operation ends, and are assumed to be £173/kW, a total cost (in 2006 prices) of £275.8 million. In DTI (2006) the future liabilities for expenditures require that £11.97 million is invested annually in an interest-earning fund, which is adequate to meet these expenses when production ceases. This is also the method proposed for the funding of nuclear waste and decommissioning liabilities used in SPRU and NERA (2006). We consider the waste costs as being a one off payment in the year following operation, and the decommissioning costs as real costs in each of the 25 years post-production. While we do not report results from sensitivity analysis directly on this issue in this paper, at the present level of assumed costs of decommissioning and waste disposal, variation does not markedly affect the levelised cost of electricity generation from nuclear power technologies. We would also wish to examine if the assumptions about how decommissioning costs are funded affects the measured levelised costs of nuclear, but these are not developed further in this paper.

[12] This assumption is also used in DTI (2007) and RAE (2004). However, for marine energy farms that comprise of large numbers of independently moored devices (such as that considered here), it may be more appropriate to consider a maintenance cost that is based on the number of devices, rather than on installed capacity. For wind energy, for example, O&M costs have reduced largely due to the increased capacity per device and thus a corresponding reduction in the number of devices that require maintenance. Although this cannot happen for wave devices, future O&M costs for marine energy are uncertain, and improvements in reliability, or other unforeseeable circumstances, may render a cost-per-device calculation more informative. We do not explore this issue further in this paper, though we note the potential value of this point for future analyses.

[13] The CAPEX figure of £3622 is an inferred value, and represents the capital expenditure that would be required in order to lead to a chosen market value of electricity, rather than being estimated in terms of per-component costs. This calculation is intended to reflect a CAPEX value of an economically viable technology, and we note that it lies within the Carbon Trust (2006) range of construction costs. We refer the reader to Allan et al. (2008) (Section 3.1, p 2738) for a more detailed description of the method by which this figure is derived. In Section 4, we consider the impact on our levelised cost calculations of changing this value. Our sensitivity analysis suggests that while changing this assumption will affect the levelised cost calculation, it does not affect the robustness of the conclusions we reach.

[14] In the absence of further publicly available cost estimates, we take this device, and its associated (inferred) construction costs, to be representative of wave energy devices. However, it should be noted that this device represents a 'class' of one only, and that there are different Wave energy technologies, each with corresponding different costs. In our sensitivity analysis (Section 4), we explore the importance of the construction cost assumptions on our levelised costs calculations. We consider the impact of alternative 'High' and 'Low' construction cost assumptions and also of given percentage changes in our central construction cost assumptions.

Table 1
Key parameters and variables for ten technologies whose levelised costs are estimated in DTI (2006).

Technology	*Capacity (MW)*	*Plant lifetime (years)*	*Construction begins*	*Operation begins*	*Gross efficiency (%)*	*Availability (%)*	*Estimated output (TWh p.a.)*	*Pre-development costs (£mn)*	*Overnight construction cost (£/kW)*[b]	*Total cost of construction in 2006 prices (£mn)*	*Fixed O&M cost (£/kW)*	*Variable O&M cost (£/kW)*
Column no.	1	2	3	4	5	6	7	8	9	10	11	12
Onshore wind	80	20	2011	2013	100.0	33.0	0.233	1.9	895[c]	71.6	44.4	–
Offshore wind	100	20	2011	2013	100.0	33.0	0.289	1.9	1513	151.3	46.0	–
PWR Nuclear	1590	40	2015	2021	35.1	84.4	11.839	250.1	1250	2051.1[d]	56.6	0
CCGT	500	35	2010	2013	58.0	85.0	3.723	–	440	220.0	7	2
Pulverised fuel	500	50	2011	2015	45.6	90.0	3.942	–	918	459.0	17	1.1
IGCC coal with CCS	500	35	2011	2015	39.0	90.0	3.942	–	1452	726.0	26	2.6
Retrofit coal	500	30	2011	2015	33.5	90.0	3.942	–	721.2	360.6	24.9	2.4964
Pulverised fuel with CCS	500	50	2011	2015	36.6	90.0	3.942	–	1162	581.0	26	2.7
IGCC coal	500	35	2011	2015	44.5	90.0	3.942	–	1069	534.5	19	1.2
CCGT with CCS	500	35	2010	2013	50.0	85.0	3.723	–	828	414.0	12.075	1.7

Technology	*Net fuel efficiency (%)*	*Fuel consumption (MWh net)*	*Conversion factor (MWh per Mtonne fuel/Mtherm)*	*Fuel consumption (Mtonnes or Mtherms)*	*Cost per tonne/therm of fuel (£)*	*Estimated operational fuel costs p.a. (£)*	*Fuel delivery cost (£/MWh)*	*Estimated operational fuel delivery costs (£)*	*Total fuel costs over lifetime of project (£)*	*Additional cost of CCS (£ per MWh)*
Column no.	13	14	15	16	17	18	19	20	21	22
Onshore wind	–	–	–	–	–	–	–	–	–	–
Offshore wind	–	–	–	–	–	–	–	–	–	–
PWR Nuclear	36.1	32,554,259	1,527,187,179,163	0.000021	2,200,000	46,896,262	0	0	1,875,850,473	–
CCGT	52.7	7,060,862	29,307	240.93	0.3655	88,054,292	0.7	4,942,603	3,254,891,338	–
Pulverised fuel	43.4	9,076974	7,277,778	1.25	25	31,180,444	0.7	6,353,882	1,876,716,277	–
IGCC coal with CCS	37.14	10,613,077	7,277,778	1.46	25	36,457,134	0.7	7,429,154,	1,536,020,091	6
Retrofit coal	31.9	12,355,522	7,277,778	1.70	25	42,442,634	0.7	8,648,866	1,532,744,995	6
Pulverised fuel with CCS	34.86	11,309,016	7,277,778	1.55	25	38,847,766	0.7	7,916,311	2,338,203,886	6
IGCC coal	42.38	9,301,348	7,277,778	1.28	25	31,951,197	0.7	6,510,944	1,346,174,911	–
CCGT with CCS	45.45	8,190,600	29,307	279.47	0.3655	102,142,979	0.7	5,733,420	3,775,673,952	3

Note to columns in Table 1: 7=(1*8760 (hours per year)*6)/1,000,000, 10=(1*(9*1000)).[a]
All costs are in real (2006) prices. 14=(7/13)*1,000,000, 16=14/15, 18=(16*1,000,000)*17, 20=14*19, 21=(18+20)*2.
[a]For On- and Offshore wind, it is assumed (DTI, 2006) that in each of the two years of construction, half of the total capital expenditures are made in each year. The time distribution of the construction costs for the non-renewable technologies are not assumed to have this feature.

[b] First-of-a-kind capital costs for each technology.
[c] Includes an additional £100/kW for "infrastructure costs".
[d] Includes costs of waste disposal during the operation of the facility at 2030, 2040, 2050 and 2060, costing £15.9m (in 2006 prices) each time.

Table 2
Present value (PV) of all cost elements, and levelised cost estimates for ten electricity generation technologies.

Technology	*PV of pre-development (PD) costs (£)*	*PV of construction (CO) costs (£)*	*PV of O&M expenditures (OM) (£)*	*PV of fuel costs (FC) (including fuel delivery) (£)*	*PV of waste and decommissioning (WD) expenditures (£)*	*PV of electrical output (O) (TWh)*	*Levelised costs (£/MWh)*
Column no.	1	2	3	4	5	6	7
Onshore wind	1,528,139	42,437,150	17,069,792	–	–	1.121	54.42
Offshore wind	1,528,139	89,675,151	22,100,722	–	–	1.389	81.56
PWR Nuclear	152,906,105	708,204,745	231,746,221	120,763,956	1,927,900	30.263	40.17
CCGT	–	137,596,165	59,588,670	506,263,596	–	20.268	34.71
Pulverised fuel	–	244,543,612	59,371,714	173,608,797	–	18.233	26.19
IGCC coal with CCS	–	386,794,471	104,599,809	197,447,542	–	17.735	44.84
Retrofit coal	–	192,118,576	98,063,523	224,686,375	–	17.336	35.70
Pulverised fuel with CCS	–	309,542,132	109,358,625	216,299,485	–	18.233	40.84
IGCC coal	–	284,768,106	64,023,585	173,043,913	–	17.735	29.42
CCGT with CCS	–	258,930,965	67,322,241	587,265,772	–	20.268	48.07

Note to columns in Table 2: $1=\Sigma_{t=0}^{n}(PD_t/(1+r)^t)$, $2=\Sigma_{t=0}^{n}(CO_t/(1+r)^t)$, $3=\Sigma_{t=0}^{n}(OM_t/(1+r)^t)$, $4=\Sigma_{t=0}^{n}(FC_t/(1+r)^t)$, $5=\Sigma_{t=0}^{n}(WD_t/(1+r)^t)$, $6=\Sigma_{t=0}^{n}(O_t/(1+r)^t)$, $7=[(1+2+3+4+5)/(6*1{,}000{,}000)]+$Col. 22 (Table 1).

Table 3
(a) Component costs used for 1 MW wave generation, in 2006 prices, £000s and % of total costs.

	Total (£000s)	%
Onshore transmission and grid upgrade	36.22	1
Undersea cables	181.12	5
Spread mooring	362.24	10
Power conversion module	1847.44	51
Concrete structures	724.88	20
Construction facilities	144.88	4
Installation	144.88	4
Construction management	181.12	5
Total	3622.44	100

(b) Component costs used for 1 MW tidal generation, in 2006 prices, £000s and % of total costs.

	Total (£000s)	%
Power conversion systems	284.31	17
Mono-pile structural elements	174.30	11
Subsea cable cost	21.13	1
Assembly and transport	17.50	1
Mono-pile/turbine installation	458.20	28
Subsea cable installation	326.37	20
Onshore items and grid interconnection	24.46	1
Overheads and omitted items	334.28	20
Total	1640.54	100

cost estimates considered for Wave cover the following elements: Onshore transmission and grid upgrade; Undersea cables; Spread mooring; Power conversion system; Concrete structures; Construction facilities; Installation; and Construction management (Allan et al., 2008).

For each component of expenditure for the class of wave energy device that we consider, the cost values and the share of the total cost are given in Table 3a. As for Offshore Wind (DTI, 2006), we abstract from the costs of developing the infrastructure necessary for both Wave and Tidal Stream technologies. This is especially important in the present context, as the extraction and productive use of electricity from Wave and Tidal Stream generation devices, and On- and Offshore wind, may require significant extensions to the electricity grid system (or the development and adoption of new storage technologies). These costs are not typically included in calculations of levelised costs.

3.1.2. Construction costs for electricity generation from Tidal Stream technologies

For Tidal Stream technologies, the construction cost figures reported in the Carbon Trust (2006) for first production models were between £1400/kW and £3000/kW. In this paper we use the costs estimated for the central case in Aggidis et al. (2010) in which independent estimates of costs came from a number of sources, including BBV (2001) and EPRI (2006). We convert these figures into 2006 prices to adjust for inflation. Cost elements used for Tidal Stream energy cover the following cost categories: Power conversion system; Mono-pile/structural elements; Subsea cable cost; Assembly and transport; Mono-pile/turbine installation; Subsea cable installation; Onshore items and grid connection; Overheads and omitted items. The values in 2006 prices (i.e. adjusted for price inflation) of each element of costs are given in Table 3b. As with Wave construction costs considered above, we abstract from any additional network infrastructure required, e.g. the costs considered are only those concerned with construction, installation and connecting the Tidal Stream devices to the existing grid to enable power to be delivered.

In 2006 prices, the construction cost figure for Tidal Stream energy used in this paper is equivalent to £1641/kW, which is towards the lower end of the first production model prices reported by Carbon Trust (2006). For a 100 MW Tidal Stream farm installation, this would mean a total project cost of £164.0 million. From Table 3 we can see that the total construction costs for the assumed Wave technology is more heavily dependent on the cost of the power conversion module element of the device, while for the Tidal Stream device assumed here, the mono-pile/device installation element constitutes a greater portion of device cost.

3.2. Operations and maintenance costs

In the DTI work, the On- and Offshore Wind renewable technologies considered are assumed to have fixed price contracts in place for the costs of operation and maintenance. These are fixed annual payments, covering all necessary repairs required during the projects lifetime. The annual cost of these operations and maintenance contracts for On- and Offshore Wind are assumed to be £44/kW and £46/kW, respectively (DTI, 2006). Comparable cost estimates for the operations and maintenance costs for Wave and Tidal Stream devices are difficult to source. This may be because there is currently no suitably developed market for maintenance contracts for these types of devices. This means that no details of the likely costs of future operation and maintenance contracts are publicly available.

Table 4
Key parameters and variables for wave and tidal electricity generation technologies.

Technology	Capacity (MW)	Plant lifetime (years)	Construction begins	Operation begins	Gross efficiency (%)	Capacity factor (%)	Estimated output (TWh p.a.)	Pre-development costs (£mn)	Overnight construction cost (£/kW)[‡]	Total cost of construction, in 2006 prices (£mn)	Fixed O&M cost (£/kW)	Variable O&M cost (£/kW)
Column no.	1	2	3	4	5	6	7	8	9	10	11	12
Wave	100	20	2011	2013	100.0	33.0	0.289	1.9	3622	362.2	98.4	-
Tidal	100	20	2011	2013	100.0	33.0	0.289	1.9	1641	164.1	29.4	-

Note to columns in Table 1: 7=(1*8760 (hours per year)*6)/1,000,000, 10=(1*(9*1000)). While DTI (2007) refers to the total annual output produced by on-and offshore wind as a fraction of that which would be assumed if the installed capacity were operating at its maximum over the whole year as "availability", "capacity factor" is a more commonly applied term for this ratio.

Table 5
Present value (PV) of all cost elements, and levelised cost estimates for Wave and Tidal electricity generation technologies.

Technology	PV of pre-development (PD) costs (£)	PV of construction (CO) costs (£)	PV of O&M expenditures (OM) (£)	PV of fuel costs (FC) (including fuel delivery) (£)	PV of waste and decommissioning (WD) expenditures (£)	PV of electrical output (O) (TWh)	Levelised costs (£/MWh)
Column no.	1	**2**	3	**4**	**5**	**6**	**7**
Wave	1,528,139	214,675,080	47,279,927	–	–	1.389	189.66
Tidal	1,528,139	97,234,188	14,112,965	–	–	1.389	81.25

Note to columns in Table 5: $1=\Sigma_{t=0}^{n}(PD_t/(1+r)^t)$, $2=\Sigma_{t=0}^{n}(CO_t/(1+r)^t)$, $3=\Sigma_{t=0}^{n}(OM_t/(1+r)^t)$, $4=\Sigma_{t=0}^{n}(FC_t/(1+r)^t)$, $5=\Sigma_{t=0}^{n}(WD_t/(1+r)^t)$, $6=\Sigma_{t=0}^{n}(O_t/(1+r)^t)$, 7=[(1+2+3+4+5)/(6*1,000,000)].

For estimating the levelised costs of Wave and Tidal Stream generation, we take O&M costs from the same studies used for estimating capital costs above. These costs are adjusted to 2006 prices to be comparable with DTI (2006) and the other costs considered. The assumed O&M costs for Wave and Tidal Stream technologies were £98.4/kW and £29.4/kW respectively. Thus, the cost of O&M is assumed to be one-third lower for Tidal Stream than for Offshore wind, and approximately double the Offshore Wind charge for Wave generation.

3.3. Electricity production

The annual amount of electricity generated by the Wave and Tidal Stream technologies is given by the product of the rated capacity of the renewable energy installation (100 MW in our example), the number of hours of operation (8760 h in a year) and the overall capacity factor of the operation. We assume a capacity factor of 33% in this paper, which is the same as that assumed in DTI (2006) for On- and Offshore wind, but higher than the 30% used for both Wave and Tidal technologies in Carbon Trust (2006). Our higher capacity factor assumptions are supported by recent estimates of the UK Wave and Tidal energy resources.

For Wave energy, Boehme et al. (2006) report, from studying the wave energy resource from 2001 to 2003 average plant capacity factors of 33.4% for the first 750 MW of Wave energy capacity installed in Scottish waters. For Tidal energy, ABPMer (2007) examine the top 50 sites of Tidal resource in the UK. By their calculations, these Tidal sites, with a total installed capacity of 1560 MW, would have an annual energy yield of 4536.14 GWh, equivalent to a capacity factor of 33.1%. The annual generation for both Wave and Tidal generators, which both have a rated capacity of 100 MW, is given as the product of the number of hours in a year, the capacity factor and the rated capacity.[15] Note that we therefore assume that output per year is constant once the capacity is installed, until the end of the device lifetime. This is calculated as: annual electricity generated (MWh)=8760 × 0.33 × 100=289,080(MWh).

3.4. Levelised cost, method and results

We present the full assumptions in Table 4 about Wave and Tidal Stream generation technologies under the same cost categories as given in Table 1, while the total costs under each element, total output, and estimated levelised cost point estimates are given in the final column of Table 5. The point estimates of levelised costs for our ten comparator technologies and Wave and Tidal Stream electricity are presented in Fig. 1. In this we break down the estimated levelised cost (in £/MWh) into the constituent costs, where each element is the relevant PV of each cost stream divided by the PV of total electrical output (in MWh).

The point estimates presented in Fig. 1 should be interpreted with a high degree of caution given the level of uncertainty surrounding individual assumptions within this model. Some general observations can be made however. Firstly, note that the point estimate of the levelised costs of electricity generation from Wave and Tidal Stream energy sources are £189.66/MWh and £81.25/MWh, respectively. These point estimates imply that Tidal Stream generation is broadly comparable in levelised cost to Offshore wind (£81.56/MWh), and around two and a third times as expensive as generation from CCGT (£34.71/MWh).

Secondly, as with On- and Offshore wind, the costs of Wave and Tidal Stream generation are principally determined by the costs of construction. Any variation in construction costs would therefore have a significant impact on the estimated levelised cost of generation for these technologies. Construction costs are an important element of the levelised costs of generation for PWR Nuclear and IGCC coal but in neither case do these constitute as large a share of total costs as for the renewable technologies.

Thirdly, the levelised costs of electricity generation are greater for renewable than non-renewable technologies. CCGT with CCS and IGCC with CCS are the most expensive of the non-renewable technologies, but their costs (£48.07 and £44.84/MWh, respectively)

[15] While the capacity factor of different devices for both wave and tidal is likely to be different, depending on the resource at the site and the technology installed at that site, some recent evidence suggests that the capacity factors for wave and tidal may be higher than that assumed here, and up to 40% (Bedard, 2007; Taylor, 2007).

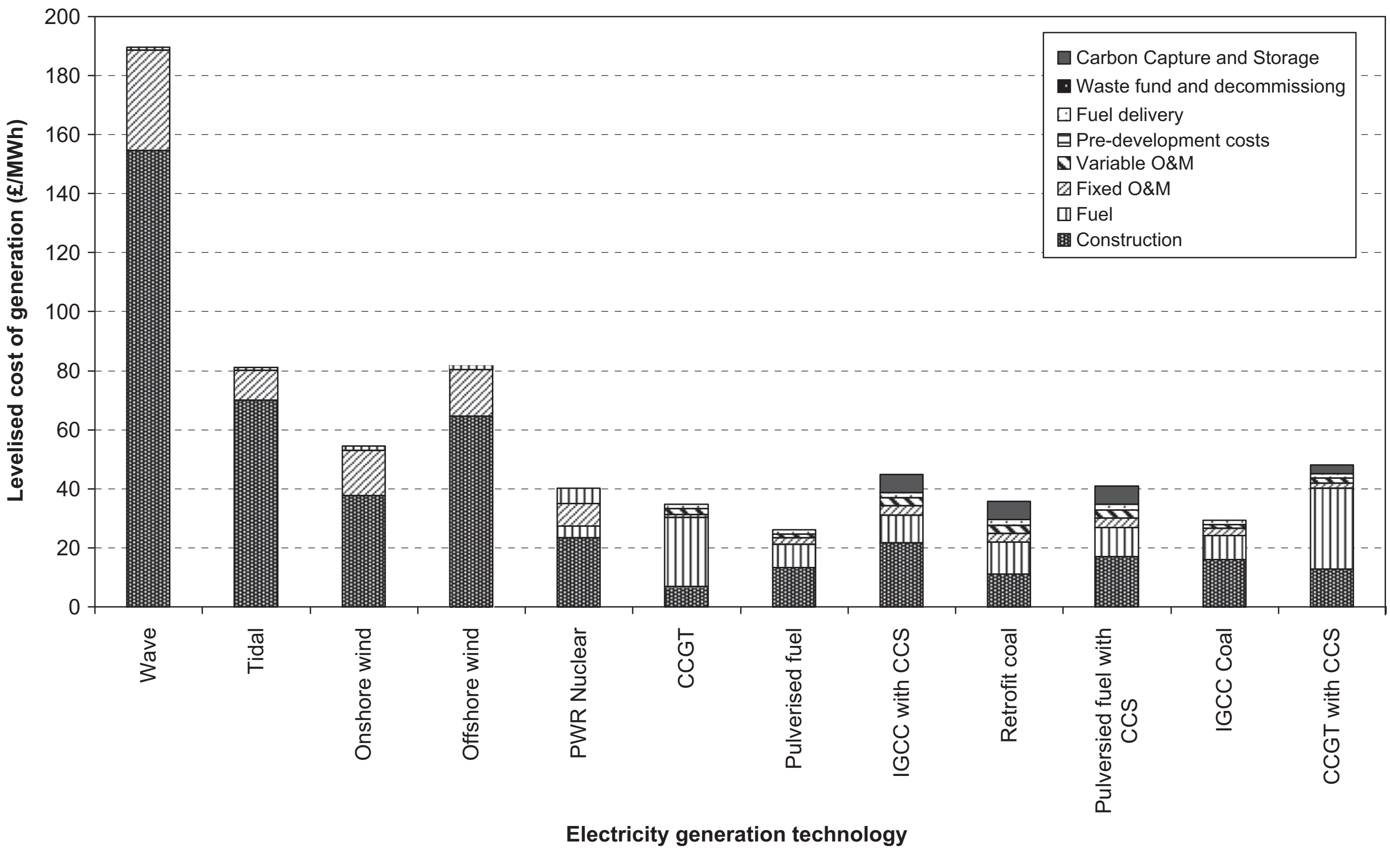

Fig. 1. Levelised costs of electricity generation, by cost component, from electricity generation technologies, £/MWh.

are lower than that for the cheapest renewable technology (Onshore wind at £54.42/MWh). This greater expense for renewable technologies, and the positive externalities (lower emissions) associated with their use – has led the government financially to support such technologies, in order that they become competitive against non-renewable alternatives. In Section 5, we explore the impacts of alternative levels of support for renewable, and specifically Wave and Tidal Stream, technologies. We turn first, however, to a sensitivity analysis of the factors driving the estimated levelised costs of electricity generation.

4. Sensitivity analysis of levelised costs

The point estimates given above are likely to be sensitive to three key variables: construction costs, fuel costs and the discount rate applied. We are interested for different reasons in these three variables. The sensitivity to construction costs is of interest because of the possibility that learning will reduce the unit (£/kW) cost for technologies approaching, but not yet at, full operational maturity. Fuel costs are of interest due to the recent volatility (and highs) observed in the prices of major fuels used for electricity generation, while sensitivity around our central value of the discount rate is required since there is considerable dispute in the literature as to the appropriate rate. Variation in any one of these variables is likely to affect, potentially significantly, the relative levelised costs of the twelve technologies considered in this paper.

4.1. Construction costs

Fig. 2 presents the range of levelised costs for each of the twelve technologies under alternative assumptions about the value of construction costs. We use DTI (2006) figures for the high and low construction costs for the ten technologies used in their study, while we take the Carbon Trust (2006) figures for the high and low construction costs for Wave and Tidal technologies. The Carbon Trust (2006) figures are the high and low estimates of construction costs for first production models in each technology.[16] Fig. 2 shows three pieces of information. The top (bottom) of the vertical line for each technology represents the levelised cost of generation (£/MWh) with the high (low) construction cost assumption. The central point estimate of levelised costs for each technology (the top of the column in Fig. 1) lies between these two bounds.

Technologies for which construction costs make up a small portion of total levelised cost (see Fig. 1), for instance CCGT and Retrofit Coal, display very little variation around the central estimate. More broadly, for non-renewable technologies the assumptions of the high and low levels of construction costs has only a small effect on the levelised cost. The same is also true for Onshore wind, perhaps given its maturity in the UK, and the consequential comparative confidence with which construction costs can be estimated.[17] The bounds around construction cost estimates for Wave and Tidal Stream are necessarily large, given the uncertainty about the types of technologies currently at the early stages of commercial development of the marine sector. Under the low construction cost assumption, the levelised costs of these two technologies are £107.66 and £70.99/MWh,

[16] The high and low estimates of capital costs for each technology are shown in Table A3.1 in Appendix 3.

[17] The high and low estimates of capital costs for onshore wind are £900/kW and £700/kW, around a central estimate of £795/kW.

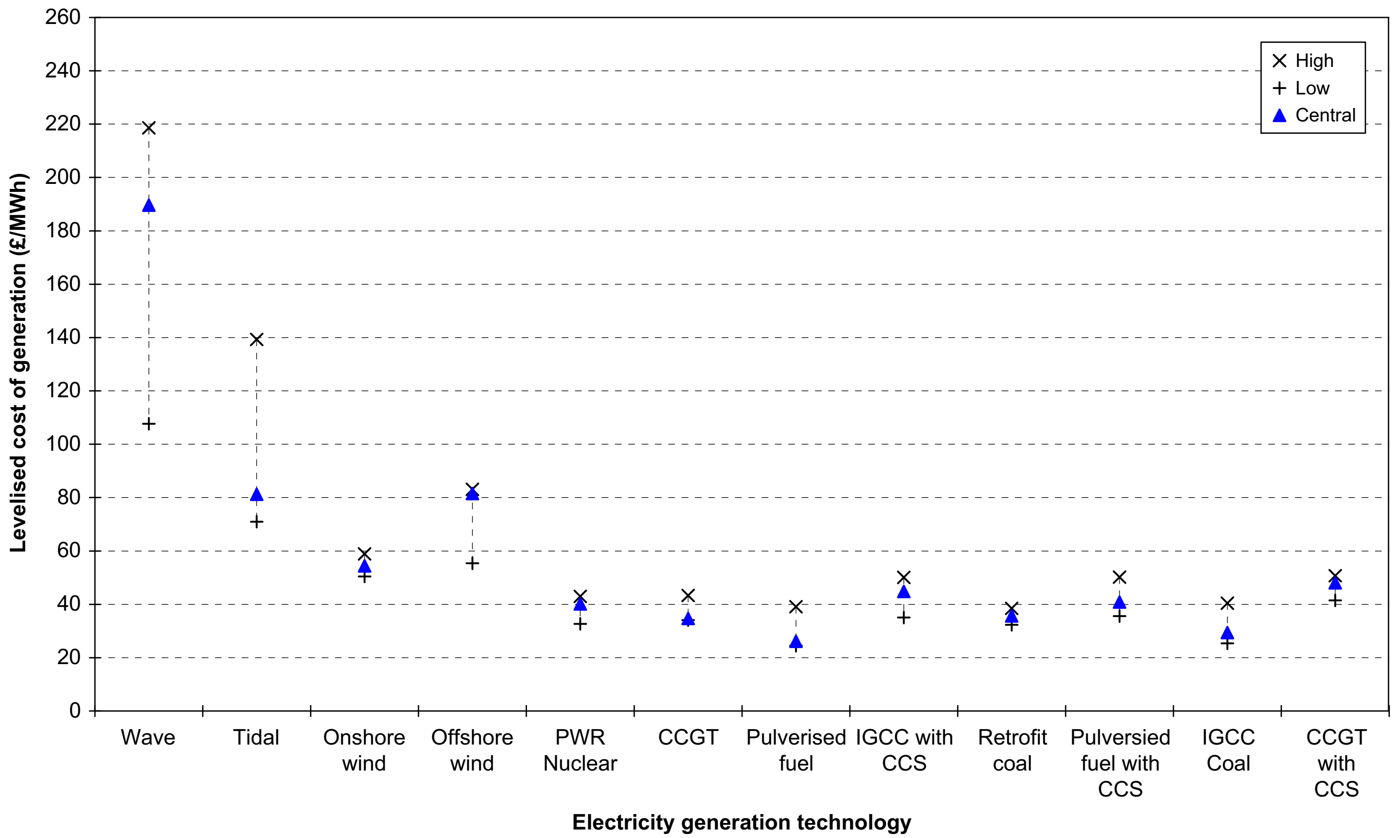

Fig. 2. Levelised cost ranges for twelve electricity generation technologies under high and low estimates of capital costs, £/MWh.

respectively, while they increase to £218.59 and £139.25/MWh if the high construction cost is assumed.

We now explore the sensitivity of levelised costs of electricity generation to reductions in construction costs. The Carbon Trust (2008) has recently announced funding to companies and researchers involved in "component technologies" which might be carried across to the marine energy industry from other industries (such as the oil and gas sector). They state that these "component technologies" are responsible for around a third of the total cost of a Wave or Tidal electricity generation device. The overall objective of this project by the Carbon Trust (2008) is "to reduce the cost of marine energy by up to 20% by 2020".

We are interested in identifying the variation in construction cost that would be necessary to alter the ranking of the levelised costs of alternative technologies. Fig. 3 shows how given percentage changes in construction costs across each technology result in changes in levelised cost of electricity generation. Note that where these lines cross the *y*-axis shows the levelised cost of generation for each technology under the central construction cost assumption (and with all other cost assumptions, as detailed above). Where lines cross in the diagram indicates that the ranking of the relative cost of technologies has altered.[18]

[18] Whilst we would expect that construction costs for newer technologies would fall relative to more traditional technologies, in Fig. 3 we assume that the change in construction costs is the same for each technology for each point along the *x*-axis. We do not intend here to suggest that a scenario whereby the construction costs of all technologies change by the same percentage is a likely one to occur. Rather, we present this figure to determine how sensitive our levelised cost calculations are to assumed changes in construction costs. The figure demonstrates that our levelised cost calculations for renewables generation are more sensitive to the assumed construction costs than that of the non-renewable technologies considered.

The results presented in Fig. 3 illustrate a number of points. Firstly, note that with reductions of 60% in construction costs, the levelised cost of Wave generation falls below £100/MWh. Secondly, the levelised cost of generation for Tidal Stream is more sensitive to the changes in the cost of construction than Offshore wind. Therefore, beginning from a position where the levelised cost of Tidal Stream is slightly lower than Offshore wind, given percentage reductions in construction costs increase the absolute cost advantage of Tidal Stream compared to Offshore wind. The levelised cost of Wave is the most sensitive to changes in construction costs, having the steepest slope of any technology shown in Fig. 3. Finally, for cost reductions of 60%, the levelised cost of Tidal Stream (but not Offshore wind) is lower than that of a non-renewable option – CCGT with CCS.

One way of measuring changes in the costs of electricity generation technologies over time (rather than the step-changes discussed in construction costs above), is through "learning rates" or "progress ratios". These measures attempt to identify the scale of reductions in costs that arise through economies of scale and technological effects, such as learning-by-doing. Learning rates are defined as "the percentage that the cost of production falls with each doubling of the total number of units produced" (Oxera, 2005, p. 14), while the progress ratio is simply the value of the learning rate subtracted from one, i.e. "a progress ratio of 80% means that costs are reduced by 20% each time the cumulative production is doubled" (Oxera, 2005, p. 14). We note that the scope for reducing the levelised cost of Wave and Tidal Stream electricity generation lies mainly in changes in the cost of construction.[19]

[19] This is one area in which significant research activity, and funding, is focused in the UK through the Marine Energy Accelerator programme, run by the Carbon Trust.

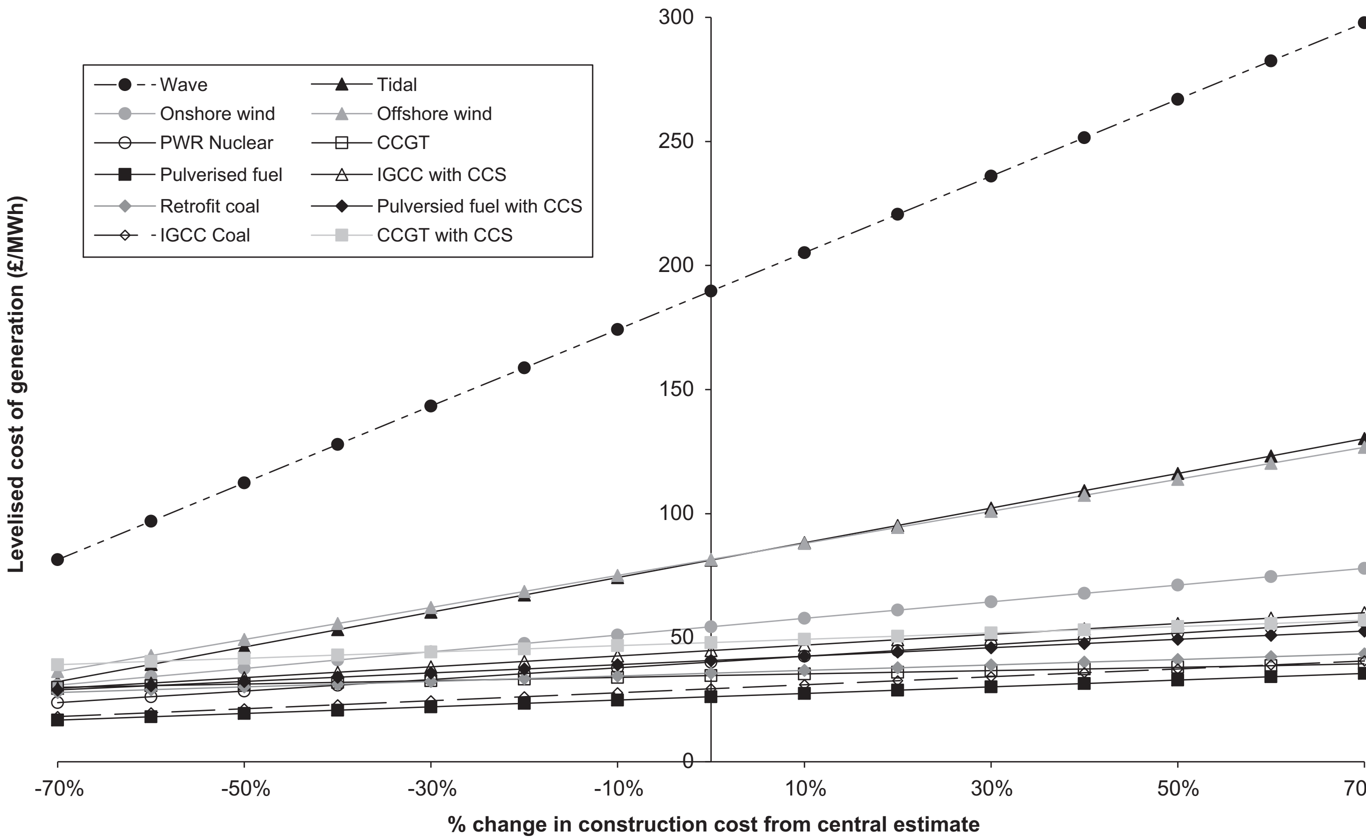

Fig. 3. Sensitivity analysis of levelised costs to construction cost variation for each technology, £/MWh.

Progress ratios of between 81 and 98% have been estimated for Onshore wind electricity generation technologies (Neij, 1997, 1999; Junginger et al., 2005), but there are a number of studies of learning rates across technologies (McDonald and Schrattenholzer, 2001; Neij, 2008). While Mukora et al. (2008) discussed the role of learning rates for wave energy from 1970, discontinuities in the data series prevented them from estimating cost reductions over the period. However, Oxera (2005) and Batten and Bahaj (2007) assume progress ratios of 85 and 90% in their estimates of future costs of marine energy generation.

Winskell et al. (2008), in their study of the learning processes associated with a technology-specific. However there are opportunities for learning in "generic" areas, shared across Wave and Tidal technologies. The authors note that there are limited learning-by-doing opportunities, given the size of the marine sector, but that there is a focus on learning-by-research. Of the potential for the perhaps necessary cost reductions, the authors also note "an emphasis on conventional design/components, rather than more radical options, possibly restricting step-changes in costs" (p. 8).[20]

4.2. Fuel costs

Increases in the cost of fuel will change the relative levelised costs of marine electricity generation compared to those technologies where fuel costs are a particularly important element. For the gas-burning technologies, the levelised cost of fuel, shown in Fig. 1, is a major component of the total levelised costs. For example, CCGT has 68% of the levelised cost coming from the fuel costs and fuel costs constitute 57% of the total levelised cost for CCGT with CCS. For the coal-burning technologies, the cost of fuel makes up between 24% and 30% of their levelised costs. For the PWR Nuclear technology, uranium costs make up just over 10% of the levelised costs. There are no direct fuel inputs to any of the four renewable energy technologies. As with Fig. 2, the bars against each technology in Fig. 4 represent the range around the central levelised cost estimate from changing the assumptions about the fuel price.[21]

The central fuel costs for gas, coal and uranium for each technology (where appropriate) are taken from DTI (2006). Similarly, for the price range for gas and uranium, we adopt DTI (2006) assumptions. In the high cost of gas case, this means assuming a cost of gas is 53 p/therm. As of the first quarter of 2008 (BERR, 2008b), the cost was 47.18 p/therm, so that our high fuel cost estimate exceeds this. However for the high cost of coal, we use the price reported in BERR (2008b) for the first quarter of 2008 of £67.04/tonne. This is greater than the high fuel cost assumed in the sensitivity results reported in DTI (2006), which was £37/tonne. In all quarters since the second quarter of 2006, the price of coal has been higher than £37/tonne. The low cost figure for coal is taken from DTI (2006).

With high fuel prices, the relative cost of Wave and Tidal Stream electricity generation changes. From being roughly five and a half times as large as the cost of CCGT under the central fuel

[20] We note that to reduce the levelised cost of electricity from wave technologies from 18.9p/kWh to 10p/kWh purely from learning reductions would require four doublings of installed capacity. If learning begins when installed capacity reaches 100 MW (Jeffrey et al., 2008) this would require an installed capacity of 1.5GW worldwide. We note that this would support a focus on examining specific initiatives which might bring about a step-change in construction costs, such as those discussed in the text above and footnote 18.

[21] The high and low estimates of fuel costs for each technology are shown in Table A3.2 in Appendix 3.

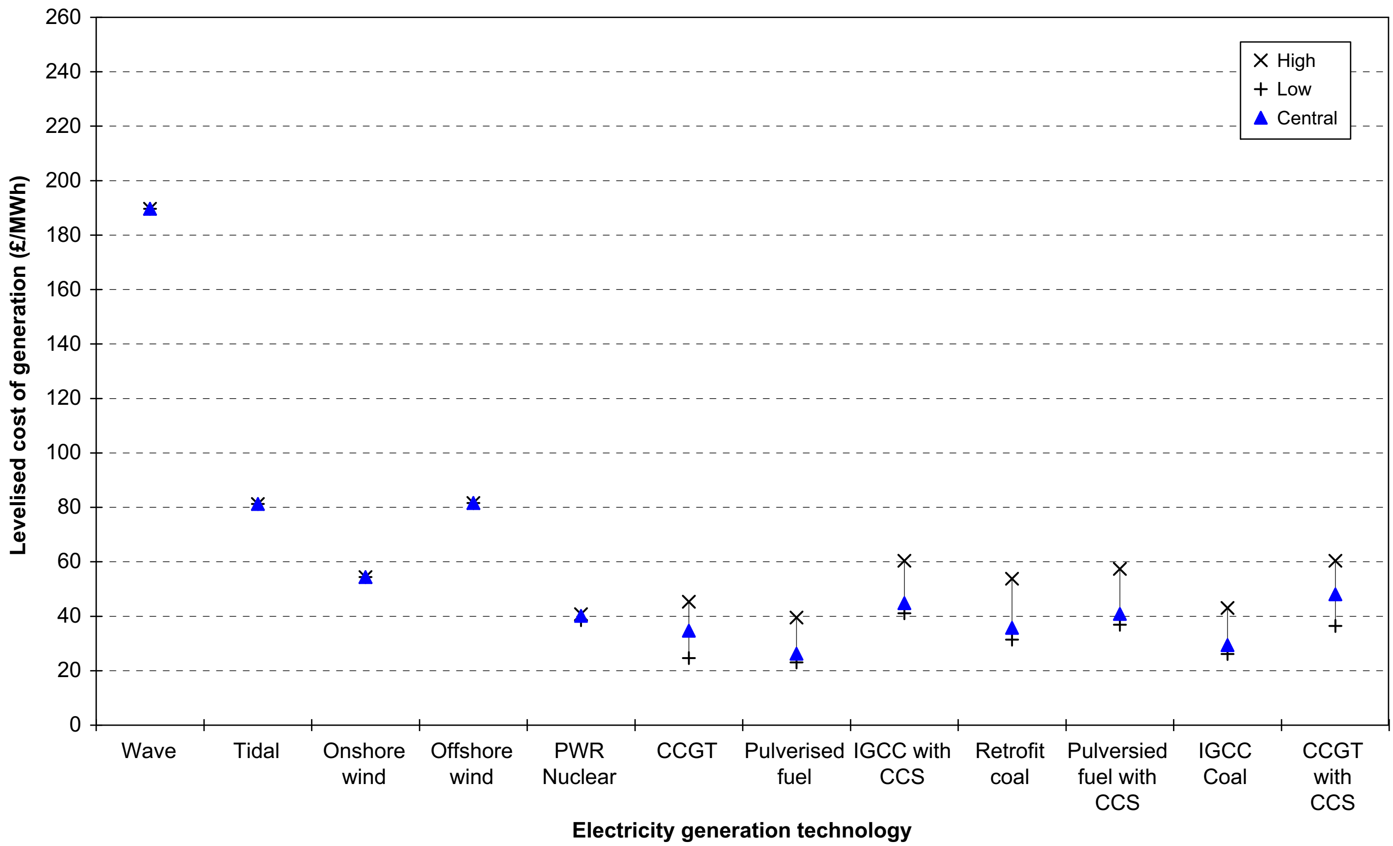

Fig. 4. Levelised cost ranges for twelve electricity generation technologies under high and low estimates of fuel costs, £/MWh.

costs, the levelised cost of Wave generation is now less than four and a quarter times as expensive as this technology. However, it is never competitive against non-renewables for the range of fuel cost changes considered in these High and Low cases. The levelised cost of Onshore wind, which remains constant under all fuel cost assumptions given its zero fuel input, is lower than that for three non-renewable technologies under the high fuel cost assumptions (IGCC with CCS—£60.39/MWh; Pulverised Fuel with CCS—£57.41/MWh; and CCGT with CCS—£60.42/MWh), and a cost which is broadly comparable with that of Retrofit coal (£53.81/MWh). This shows how the competitiveness of renewable and non-renewable technologies is sensitive to fuel prices. While the latter have been volatile in reaction to shifting market expectations, the non-renewable nature of the resources implies an underlying trend increase unless the structure of demand or supply undergoes a radical change.[22]

Fig. 5 shows how the levelised costs of these twelve technologies vary as fuel costs change by given percentages. Here we focus only on the impact of increases in the cost of fuel relative to the cost assumed in the central case. As can be seen from this diagram, the two technologies whose costs are the most sensitive to the assumed fuel costs are CCGT and CCGT with CCS. Their levelised cost increases significantly as the fuel costs are increased, with CCGT going from the third cheapest generation technology (on a £/MWh basis) under the central fuel cost assumption, to the most expensive of the non-renewable technologies (with the exception of CCGT with CCS) and more expensive than Onshore wind, for a fuel price increase of more than 80%.

4.3. Discount rate

Eq. (1) shows the importance of the choice of the discount rate to be used to convert the stream of future costs and electrical output into their Present Values. Increasing (lowering) the discount rate, other things remaining equal, will lower (raise) the present value of both generation costs and output. However, since for all technologies, there are initial construction costs which have a larger present value than ongoing expenditures, a higher (lower) discount rate means that the present value of output will fall (rise) by more than the present value of costs, increasing (lowering) the total levelised cost. Thus, an increase in the discount rate will adversely affect those technologies which have longer lifetimes (other things being equal), but principally those for whom initial (pre-development and) construction costs make up a larger portion of the total levelised cost. For these reasons, we would expect that the levelised costs of Wave and Tidal Stream would be particularly sensitive to the choice of discount rate.

In a conventional Cost Benefit Analysis, such as that used for evaluating public projects in the UK (HM Treasury, 2003), the discount rate used should be the social time preference rate. This reflects the notion that society values consumption today more than consumption in the future, with the discount rate being the cost of deferred consumption between time periods. HM Treasury (2003) suggests a social time preference rate of 3.5% per annum

[22] Recall from Section 2.1 however that any trend increase in the cost of inputs are not typically considered in levelised cost calculations, and have not been considered in this paper.

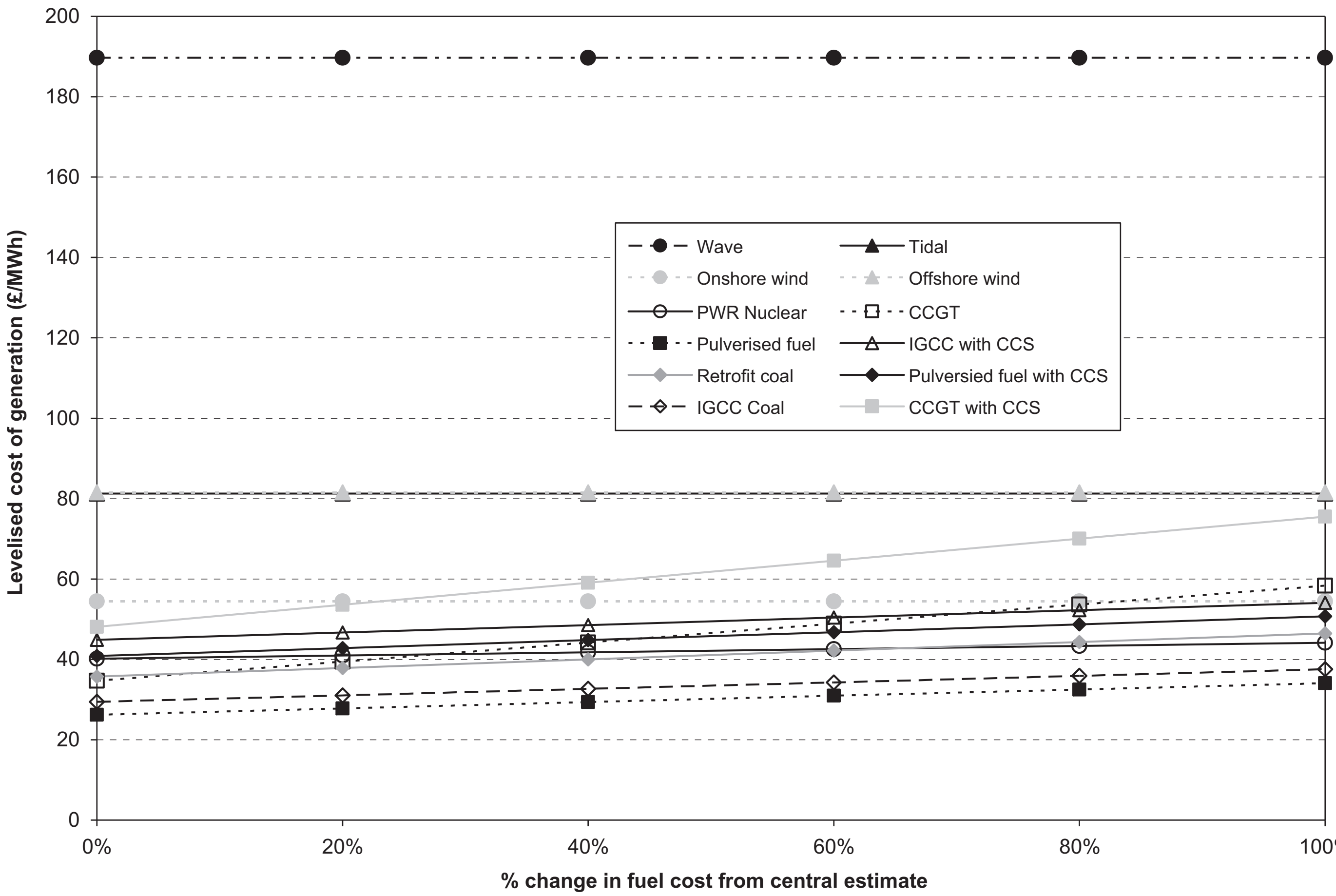

Fig. 5. Sensitivity analysis of levelised costs to fuel cost variation for each technology, £/MWh.

for all projects.[23] When firms assess investment projects, on the other hand, the appropriate discount rate to be used is not the social rate of time preference, but the return on investment necessary, or the weighted average cost of capital for the company. This cost of capital will reflect the (perceived) risk of the investment, with cost of capital increasing (not necessarily linearly) as the riskiness of the investment increases. In this study, we are concerned only with the private levelised costs of electricity generation. These costs reflect the relative competitiveness of Wave and Tidal Stream energy, and help inform private investment decisions. As such, in our sensitivity analysis, we consider a range of private discount rates, rather than the social time preference rate. However, we note that a useful extension to the current paper would be to consider the social costs associated with different electricity generation types. Such analysis would require including externalities to production (such as environmental pollution and additional system costs) in the overall cost calculation. Correspondingly, the costs of each technology would reflect the "social" levelised cost, and the appropriate rate to discount real costs and revenues would then be the social rate of time preference (HM Treasury, 2003).

Redpoint Energy Ltd (2008) show that the discount rate might differ between investors, for instance the cost of capital for "vertically integrated players" ("VIPs") may be lower than for independent investors. This results in a lower levelised cost for these "VIPs" for the same generation technology. Oxera (2005), in their study of the commercial viability of renewable electricity generation technologies, use different cost of capital assumptions for different renewable electricity generation technologies. Their "base scenario" takes a cost of capital of 7.9% for more "established" renewable technologies (landfill gas, onshore wind, micro hydro – less than 1.25 MW capacity and small hydro, with capacity between 1.25 and 20 MW – and sewage gas) while they use a higher cost of capital (11.9%) for "riskier" technologies – offshore wind, photovoltaics, tidal, wave, gasification of wastes and biomass. Under the "high case sensitivity" analysis they report, these two costs of capital increase to 9.2% and 13.1%, respectively.

In the sensitivity results that follow, we use a high and a low discount rate of 15% and 6%, respectively (recall that the central discount rate – as used for the calculation of levelised costs in DTI (2006) and used for all the preceding results – is 10%). These two interest rates cover the range of discount rates used for marine energy devices in Carbon Trust (2006), as well as covering the range of cost of capital rates employed in Oxera (2005) (for less established renewable technologies) and Redpoint Energy Ltd (2008) as described above. Results under these two alternative discount rates are shown in Fig. 6.

[23] This is based on the formula social time preference rate (STPR)$=\rho+\mu g$, where ρ is the "rate at which individuals discount future consumption over present consumption, on the assumption that no change in per capita consumption is expected" (HM Treasury, 2003, p. 111), $\mu$is the elasticity of marginal utility of consumption with respect to utility and $g$is the annual growth in per capita consumption. The product of the final two terms reflects the notion that, per capita consumption is expected to grow in the future, that the marginal utility of consumption will be lower in the future relative to today. The values of ρ, μ and g used in HM Treasury (2003) are 1.5%, 1.0 and 2% respectively.

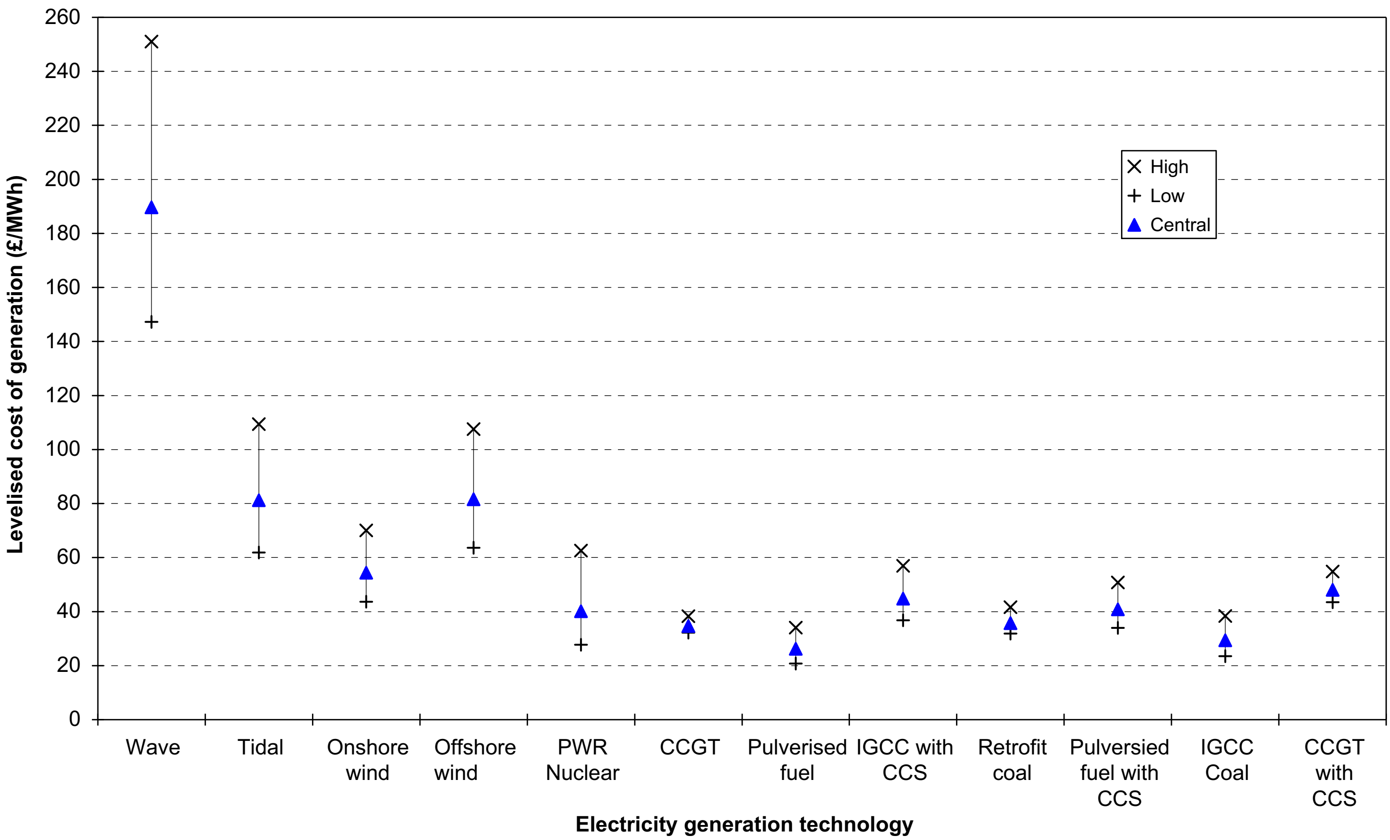

Fig. 6. Levelised cost ranges for twelve electricity generation technologies under high and low estimates of discount rate, £/MWh.

Fig. 6 confirms that for all technologies a higher discount rate means that the PV of output and generation costs fall, however the PV of output declines by more[24] and so, for all technologies, the levelised cost of generation increases. The opposite is true for a lower discount rate. An interest rate of 6% lowers the costs of Wave and Tidal Stream energy devices to £147.28/MWh and £61.84/MWh, respectively. Increasing the discount rate to 15% on the other hand, increases the costs of these two technologies to £251.00/MWh and £109.38/MWh.

5. The importance of “banded” support mechanisms for the levelised costs of marine energy

The Renewables Obligation (RO) scheme has succeeded in delivering investment in UK Onshore wind capacity, with three times as much wind capacity installed in the UK between 2002 (the first year of the RO) and 2006, as against the previous thirteen year period (when the Non Fossil Fuel Obligation was in place) (BWEA, 2007). Until 1 April 2009, the RO mechanism was “technology-blind”, such that all renewable technologies received the same financial support: one ROC per MWh of electricity sourced from accredited generation. The recent introduction of “banding” within the RO system (Renewables Obligation Order, 2009a,b,c,d; Renewables Obligation Amendment Order, 2010a,b), is intended to provide additional incentives for investment in emerging, and thus generally more expensive, renewable technologies. Technologies are presently grouped into five “bands”, with each band receiving multiples (or fractions) of ROCs for their electricity generation. Among the technologies assumed to be “emerging” and in receipt of additional ROCs support are wave, tidal, offshore wind and biomass generation. Each of these generation types are entitled to two ROCs per MWh, compared to one ROC/MWh for onshore wind and hydro-electric generation. This effectively lowers the cost to developers of wave, tidal, offshore wind and biomass electricity generation facilities.

These ROC “bands” are applicable across the UK. However, the Scottish Government has indicated its intention to introduce significantly higher levels of ROC support to electricity generation from Wave and Tidal sources in Scottish waters. It is proposed that Wave and Tidal technologies might receive, in total (i.e. including the UK “banded” support) 5 ROCs and 3 ROCs for each MWh of electricity generated (Scottish Government, 2008).

In the year 2006–7, one ROC was worth £49.28 (Ofgem, 2008) to an accredited renewable electricity generator. Ideally, we would use a forecast for the real value of a ROC as renewable energy generation grows over the coming years. This price will be determined by the shortfall between the annual share of total electricity supply that UK electricity supply companies must provide from accredited generation and the amount of ROC-accredited output in that year.[25] Recent work by SQW Energy

[24] The smallest difference between the decline in the PV of output and the PV of costs is for the CCGT technology, where, with a higher discount rate, the PV of costs falls by 42.0%, while the PV of output falls by 47.5%.

[25] SQW Energy et al. (2008) describe three cases in the RO market: Firstly, “shortfall” is where RO compliance is lower than the obligation level for that year, and the revenue to renewable generators from RO has a floor at the buy-out price (£35.76 in 2008/9). Secondly, “headroom” when the expected level of compliance plus 8% is greater than the required obligation level for that year. The revenue in this case is fixed at 8% above the buy-out price for that year, but the specific buy-out price would depend upon how the expected level of compliance differed from actual level of compliance. The third case is of “ski-slope” where the total cost of the obligation (to consumers) is capped by reducing the RO buy-out price. This is currently proposed to occur when the maximum obligation level rises to 20% of eligible supply.

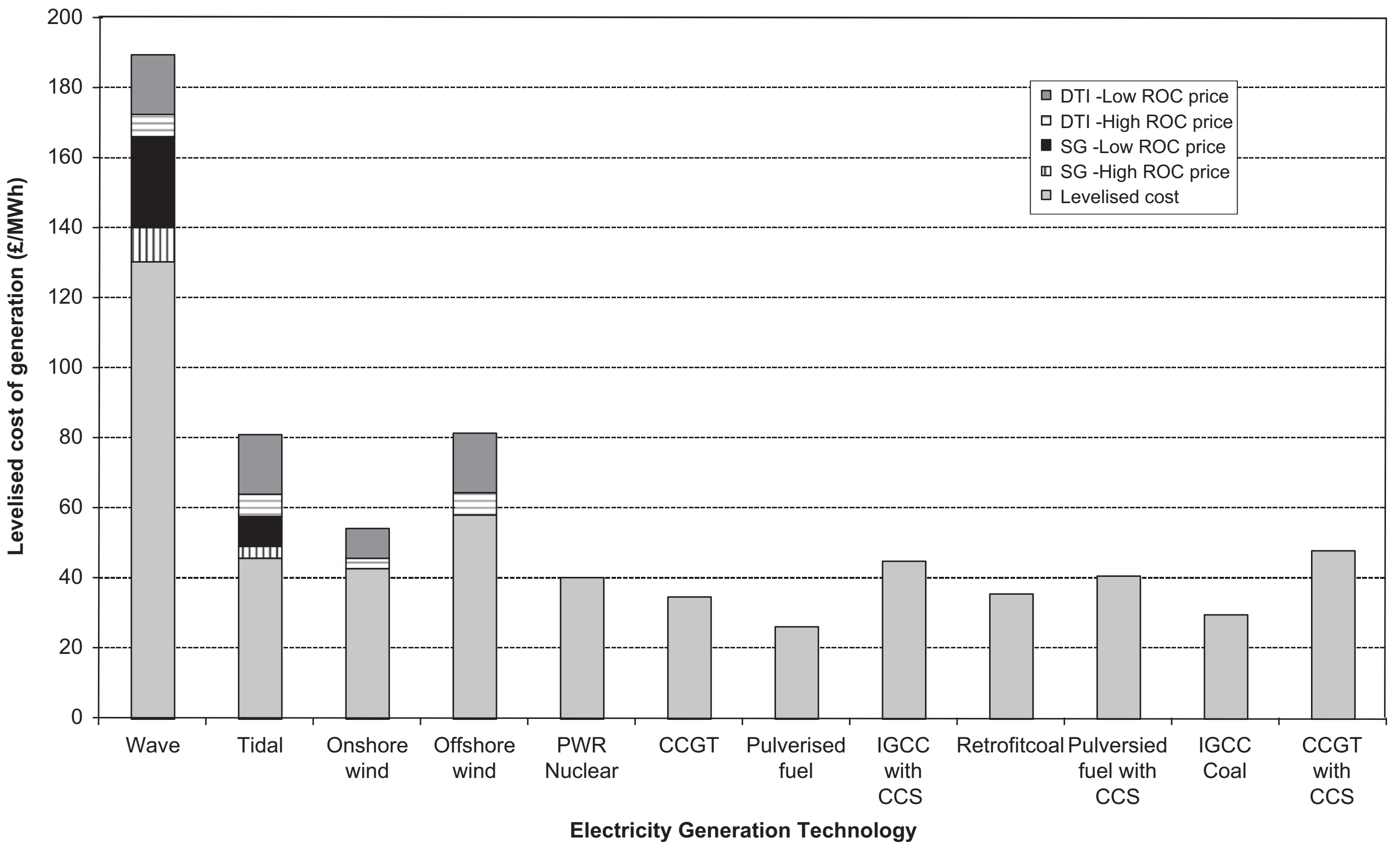

Fig. 7. Levelised costs of electricity generation, including proposed levels of subsidies to renewable electricity generation, £/MWh.

et al. (2008) projected ROC output that reaches the headroom level (see footnote 16) in 2012/13 under their central scenario, with ROC prices from this same year onwards remaining 8% above the buyout price.

ROCs impact directly on the revenues associated with renewable technologies. However, it is instructive to treat ROCs here "as if" they constituted a subsidy to costs, to illustrate the importance of the scale of ROCs for competitiveness of alternative technologies. For simplicity, we illustrate the impact that multiple ROCs awarded to Wave and Tidal Stream generation might have on the competitiveness of these technologies by making the assumption that, over the lifetime of the Wave and Tidal Stream projects the value of a ROC to generators is constant, and worth either £35.90/MWh (in 2006 prices)[26] in a low ROC price scenario or £49.28/MWh (in 2006 prices)[27] in a high ROC price scenario.[28] Over the lifetime of the Wave and Tidal Stream facilities, consequently, the (real) value of this subsidy (assuming a constant ROC price) would be the product of the annual electrical output and the ROC price (multiplied by any "multiple ROC" which is also given for electricity generated from Wave or Tidal Stream sources). Again, these values would be discounted to their present values before being included in the levelised cost calculations presented.[29] We explore the two proposed levels under the UK and Scottish proposals: firstly, the "banding" rates that accord with current legislation across the UK[30] which are set out in Appendix 2, where Onshore Wind receives 1 ROC per MWh, and Wave, Tidal and Offshore Wind receive 2 ROCs per MWh; and the second case, proposed by the Scottish Government (2008), where the same subsidy rates apply for On- and Offshore Wind, but Wave and Tidal earn an additional 3 and 1 ROCs, respectively. The impact on the levelised costs of electricity generation is shown in Fig. 7.

The maximum values of the levelised costs of generation for each technology in Fig. 7 are the same as those in Fig. 1. Wave and Tidal Stream electricity generation have levelised costs of £189.66/MWh and £81.25/MWh respectively, as estimated in Section 3. Under ROC "banding", the levelised costs of On- and Offshore Wind, Wave and Tidal Stream technologies will be affected by the ROC price and number of ROCs received. The Scottish Government (2008) proposals for the additional "banded" levels of public support to Wave and Tidal Stream renewable energy technologies further reduce the levelised costs of those technologies. The top "box" in the bar chart of levelised cost indicates the impact on the levelised costs according to the current ROC "bands" in place across the UK and under a low ROC

[26] This is the 2006–7 buyout price (£33.24) plus 8%.

[27] We use the 2006–7 value of a ROC to a renewable generator (Ofgem, 2008) to inform the high ROC price scenario. More recently, the value of a ROC to a supplier has been calculated to be £54.37 for the year 2008–9 (Ofgem, 2010), which is equivalent to £51.54 in 2006 prices. The value of £49.28 that we use is close to the average value of a ROC to a renewable generator over the period 2005–6 to 2008–9 (£49.02, in 2006 prices). Projections of the future value of ROCs to renewable electricity generators (such as SQW Energy et al., 2008) typically forecast values between the high and low ROC prices we assume here.

[28] We do, as stated above, assume that other costs remain constant (in 2006 prices) over the lifetime of the device, for instance the costs of labour incorporated in Operations and Maintenance costs, so this assumption for ROCs is consistent with earlier assumptions.

[29] Under the simplifying assumption of constant output and constant variable costs in each year the device is operational, this is identical to subtracting the present value of the ROCs.

[30] As set out in: the Renewables Obligation Order (2009); Renewables Obligation (Amendment) Order 2010; Renewables Obligation (Northern Ireland) Order (2009); Renewables Obligation (Northern Ireland) Amendment Order 2010; Renewables Obligation (Scotland) Order 2010; and the Renewables Obligation (Scotland) Amendment Order 2010.

price. The second (horizontally lined) box down the columns for these technologies shows the additional reduction in levelised costs under the current "bands" and a high ROC price. Thirdly, the Scottish Government's (2008) proposals for additional ROCs for Wave and Tidal generation lower levelised costs further, by the amount of the black section in the columns for the marine technologies in Fig. 7. Finally, under the high ROC price, there is a further small reduction in the levelised costs for these two technologies.

With the current "banding" levels and a low ROC price Onshore wind has the lowest levelised cost all of the renewable technologies, Offshore wind and Tidal Stream have similar cost levels and Wave generation is much more expensive. With the DTI "bands" and the high ROC price assumption, the levelised cost of generation for Wave and Tidal Stream technologies is lowered to £166.00 and £57.57/MWh, respectively, while the cost of On- and Offshore Wind fall to £42.58 and £57.88/MWh, respectively. This implies that the cost of Tidal Stream electricity generation, which was 49% greater than Onshore Wind originally, would now be 35% greater than Onshore Wind. Offshore wind continues to have a slightly greater cost than Tidal Stream generation. Under these assumptions, only Onshore Wind has a cost level close to some of the non-renewable technologies.

The additional support proposed for accredited Wave and Tidal generation facilities installed in Scotland, as described above, can be regarded as effectively reducing the levelised costs of these two technologies. The costs of Wave and Tidal Stream electricity generation are reduced to £130.47 and £45.73/MWh, respectively, so that Tidal Stream electricity is only 7.39% more expensive than Onshore Wind, while the pre-support cost of Tidal Stream was almost fifty per cent greater than Onshore Wind. The cost of electricity generation from Wave sources is now only 3.8 times as expensive as CCGT Gas, down from almost 5.5 times as expensive when measured by levelised costs without any support mechanisms. These proposals could therefore have a very significant impact on the adoption of both Wave and Tidal Stream technologies, although cost differentials remain.[31] At this level of support, the cost of Tidal Stream moves close to that for non-renewable technologies.

The financial support for Wave and Tidal electricity generation will have consequences for the ROC market and these are quantified by SQW Energy et al. (2008). Also, there is expected to be an increase in the cost of electricity to consumers due to the introduction of "banded" ROCs. SQW Energy et al. (2008) found that both of these impacts would be small: the maximum impact of the changes proposed would be to reduce the UK ROC price by 1.5% and to decrease renewable energy output by up to 1.3%. The introduction of banded ROCs significantly improves the competitiveness of both Tidal Stream and Wave technologies. However, our calculations suggest that the representative Wave technology that we consider here remains more expensive on a standalone levelised cost basis than that for the other technologies presented here. In contrast, the representative Tidal Stream technology becomes marginally cheaper than Offshore wind in our calculations to date, but remains more expensive than Onshore wind generation.

6. Discussion

This paper can be extended in a number of ways. The capital costs are fundamental to the estimated levelised costs of these renewable energy technologies. As noted above, there is considerable research activity in ongoing into the costs of renewable generation over time, examining the size and nature of "learning rates" or "progress ratios". The scale of potential learning rates for capital costs, and thus the levelised cost of Wave and Tidal energy will be of fundamental importance to the penetration of these technologies into the UK electricity sector.

Secondly, and as noted in Section 2, we do not attempt to extend the calculation of levelised costs to include externalities from production, although the introduction of ROCs is motivated by such externalities in the recognition that without financial support, most renewable electricity generation technologies are too expensive to see significant take up in a liberalised market. From a policy perspective, the social costs and benefits associated with each technology should be identified (including, for example, externalities from production such as environmental impacts), ideally in a comprehensive cost–benefit analysis, which would then guide the judgment on the appropriate level of ROC support.

A further major externality which is not included in the calculations presented in this note is the additional costs to the operation of the electricity system from having renewable generation providing variable power to the electricity grid. Estimates of the costs of these have been made elsewhere (e.g. Gross et al., 2006; Skea et al., 2008; Sinclair Knight Merz, 2008), and should, alongside values for the pollution externalities mentioned above, be incorporated in a full cost–benefit analysis. We do note the work of Sinden (2007) and Clarke et al. (2006) which show that geographic diversification of intermittent generation can considerably reduce output variability. As noted in the introduction however, in this paper we are concerned only with the private levelised costs of electricity generation technologies, so any additional systems costs are not included.

A third extension would be to examine how the levelised costs of electricity generation could possibly differ between different locations. Stallard et al. (2008), for instance, examine the case where marine energy resources vary between locations, with accompanying cost differences through spatial variations in operations and maintenance costs. We might expect that peripherality will affect an energy developer's investment decision. However, the levelised cost of generation calculated here takes no account of the location of the technology. Extending levelised costs to reflect regional, or location, differences would allow researchers to address the issue of how peripherality might affect the development of Wave and Tidal energy in the UK. Finally, private developers will not make investment decisions solely on the basis of estimates of levelised costs: a complete analysis must include projected revenues and the calculation of expected net present values (NPVs) and their associated distributions for sensitivity analysis. Such an analysis could examine how this NPV would differ under alternative assumptions about market behaviour, and the volatility of revenues, as well as costs.

We end on a further cautionary note: while technologies are widely compared in terms of their levelised costs, a least-cost approach to the adoption and development of energy technologies may be inappropriate. From society's perspective at least (and also from that of major private investors) what matters are new technologies' contributions to the *portfolio* of electricity generation technologies as is recognised in the research of Shimon Awerbuch and others (see e.g. Bazilian and Roques, 2008). Simple comparisons of standalone levelised costs (or profitability) may provide a misleading criterion for technology adoption and deployment, particularly given that renewable technologies exhibit zero fuel cost risk and, in a world of highly volatile fuel prices, this may prove to be a valuable attribute (Awerbuch et al., 2003).

[31] However, to qualify for the higher levels of aid in Scotland, the specific renewable electricity project must have had no previous support from either the UK or Scottish Governments. In order to be eligible, generating stations must also be situated in Scottish waters or in the Scottish area of the Renewable Energy Zone and be connected directly to a transmission and distribution network in Scotland (Scottish Government, 2008).

7. Conclusions

In this paper we provide comparisons of the levelised cost of twelve electricity generation technologies for the UK, which covers non-renewable and renewable electricity technologies, including generation from Wave and Tidal Stream sources. Data on the private costs of generation for each technology come from UK Government sources (DTI, 2006) for ten non-marine technologies, and from publicly available sources for the Wave and Tidal Stream technologies. We use the discounting method to convert future costs and future electrical output into their present values in a consistent way for all technologies. We find point estimates of the levelised costs of Wave and Tidal Stream electricity generation of £189.68 and £81.25/MWh, respectively, at 2006 prices. We use sensitivity analysis to show how important certain assumptions are for the levelised costs of Wave and Tidal Stream generation. As would be expected, construction costs, fuel prices and the discount rate are key factors governing the relative levelised costs of alternative electricity generation technologies.

We also find that the current provision of "double ROCs" to Wave and Tidal Stream energy generation by the UK Government is not sufficient to reduce the levelised costs to a level comparable to non-renewable technologies. The further support proposed by the Scottish Government (2008) producing a combined total of 3 ROCs to each MWh generated from Tidal, and 5 ROCs/MWh from Wave generation would reduce the cost of Tidal Stream technology so as to make it broadly comparable to that of Onshore Wind, and cheaper than one of the non-renewable technologies considered here.

Acknowledgements

The authors acknowledge the support of the Engineering and Physical Science Research Council through the SuperGen Marine Energy Research Consortium (reference: EP/E040136/1) as well as the assistance of Chris Chown at the Department of Business Enterprise and Regulatory Reform for advice and clarifications. The authors are also grateful to Robin Wallace and Mark Winskell (both Institute for Energy Systems, University of Edinburgh) for their comments, and to two anonymous referees whose extensive comments have improved the paper considerably. The authors bear sole responsibility for any remaining errors or omissions.

Appendix A. Supplementary material

Supplementary data associated with this article can be found in the online version at doi:10.1016/j.enpol.2010.08.029.

References

ABPMer, 2007. Quantification of exploitable Tidal energy resources in UK waters, report funded by the npower Juice fund, published July 2007, available online at ⟨http://www.abpmer.co.uk/files/report.pdf⟩.

Aggidis, G.A., Allan, G.J., McCabe, A., McGregor, P.G., Rothschild, R., Swales, J.K., Turner, K., 2010. Modelling the potential economic impact of tidal devices on the UK, University of Strathclyde Discussion Paper in Economics, No. XX, October.

Allan, G.J., Bryden, I., McGregor, P.G., Stallard, T., Swales, J.K., Turner, K., Wallace, A.R., 2008. Concurrent and legacy economic and environmental impacts from establishing a marine energy sector in Scotland. Energy Policy 36, 2734–2753.

Awerbuch, S., 2003. Determining the real cost: why renewable power is more cost competitive than previously believed. Renewable Energy World March–April 2003, available online at ⟨http://www.awerbuch.com/shimonpages/shimondocs/REW-may-03.doc⟩.

Batten, W.M.J., Bahaj, A.S., 2007. An assessment of growth scenarios and implications for ocean energy industries in Europe, Seventh European Wave and Tidal Energy Conference, Porto, Portugal, 11–13 September 2007. ⟨http://eprints.soton.ac.uk/53003/http://64.233.183.132/search?q=cache:x0zIvtoRrBoJ:www.see.ed.ac.uk/comp/pcsoft/apps/shire/.n/Research-Institutes/ies/.n/ESI/Conf_proceedings/EWTEC_2007/papers/1065.pdf+An+assessment+of+growth+scenarios+and+implications+for+ocean+energy+industries+in+Europe&hl=en&ct=clnk&cd=2&gl=uk⟩.

Bazilian, M., Roques, F. (Eds.), 2008. Analytical methods for energy diversity and security: mean-variance optimisation for electric utilities planning: a tribute to the work of Dr. Shimon Awerbuch. Elsevier, Amsterdam.

BBV (Binnie, Black, and Veatch), in association with IT Power, 2001. The Commercial Prospects for Tidal Stream Power, ETSU T/06/00209/REP, DTI/Pub URN 01/1011.

Bedard, R., 2007. Power and energy from the ocean energy waves and tides: a primer, available online at ⟨http://www.oceanrenewable.com/wp-content/uploads/2009/05/power-and-energy-from-the-ocean-waves-and-tides.pdf⟩.

Boehme, T., Taylor, J., Wallace, R., Bialek, J., 2006. Matching Renewable Electricity Generation with Demand: Academic Study for the Scottish Executive by the University of Edinburgh, report produced April 2006, available online at ⟨http://www.scotland.gov.uk/Publications/2006/04/24110728/0⟩.

Business Enterprise and Regulatory Reform, 2008a. Renewables Obligation Consultation: Government Response. Department for Business Enterprise and Regulatory Reform, January 2008.

Business Enterprise and Regulatory Reform, 2008b. Quarterly Energy Prices. Department of for Business Enterprise and Regulatory Reform available online at ⟨http://www.berr.gov.uk/files/file47741.pdf⟩.

British Wind Energy Association, 2007. The Renewables Obligation website access 27th February 2008.

Carbon Trust, 2006. Future Marine Energy: Results of the Marine Energy Challenge: Cost competitiveness and growth of wave and tidal stream energy. Carbon Trust, January 2006.

Carbon Trust, 2008. Carbon Trust to slash costs of marine energy by 20%. press release available online at⟨http://www.carbontrust.co.uk/publicsites/cScape.CT.CoreTemplates/PressCentreArticle.aspx?NRMODE=Published&NRNODEGUID=%7b5A46171C-BBFF-4523-A566-69E9738040E7%7d&NRORIGINALURL=%2fNews%2fpresscentre%2fmarine_energy_costs%2ehtm&NRCACHEHINT=Guest⟩.

Clarke, J.A., Connor, G., Grant, A.D., Johnstone, C.M., 2006. Regulating the output characteristics of tidal current power stations to facilitate better base load matching over the lunar cycle. Renewable Energy 31 (2), 173–180.

Department of Trade and Industry, 2006. Overview of Modelling of the Relative Electricity Generating Costs of Different Technologies. Annex B to the UK Energy Review, July 2006.

Ernst and Young, 2007. Impact of banding the Renewables Obligation – Costs of electricity production, report by Ernst and Young to the Department of Trade and Industry, URN 07/948, published in April 2007.

EPRI (Electric Power Research Institute) TISEC Project, 2006. Available online from: ⟨http://www.epri.com/oceanenergy/streamenergy.html⟩ (downloaded February, 2007).

Gross, R., Heptonstall, P., Anderson, D., Green, T., Leach, M., Skea, J., 2006. The costs and impacts of intermittency: an assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network. A report of the Technology ad Policy Assessment Function of the UK Energy Research Centre, with financial support from the Carbon Trust, March 2006.

Gross, R., Heptonstall, P., Blyth, W., 2007. Investment in electricity generation: the role of costs, incentives and risks. A report produced by Imperial College Centre for Energy Policy and Technology (ICEPT) for the Technology and Policy Assessment Function of the UK Energy Research Centre, May 2007.

Heal, G., 2007. Discounting: a review of the basic economics. The University of Chicago Law Review 74 (1), 59–77.

HM Treasury, 2003. The Green Book: appraisal and Evaluation in Central Government: Treasury Guidance. HMSO, London.

Horn, M., Führing, H., Rheinländer, J., 2004. Economic analysis of integrated solar combined cycle power plants, A sample case: the economic feasibility of an ISCCS power plant in Egypt. Energy 29, 935–945.

Jeffrey, H.F. 2008. Learning investments and cost reduction in the marine energy sector, presentation at British Institute of Energy Economics Conference, Oxford, September 2008.

Jeong, S.-K., Kim, K.-S., Park, J.-W., Lim, D.-S., Lee, S.-M., 2008. Economic comparison between coal-fired and liquefied natural gas combined cycle power plants considering carbon tax: Korean case. Energy 33, 1320–1330.

Junginger, M., Faaij, A., Turkenburg, W., 2005. Global experience curves for wind farms. Energy Policy 33, 133–150.

Kammen, D.M., Pacca, S., 2004. Assessing the costs of electricity. Annual Review of Environmental Resources 29, 301–344.

McDonald, A., Schrattenholzer, L., 2001. Learning rates for energy technologies. Energy Policy 29, 255–261.

Mukora, A., Jeffrey, H., Winskel, M., Mueller, M. 2008. Wave Energy Technology Development Review in the UK: application of the Learning Curve Concept, 1970-1999, paper presented at the 10th World Renewable Energy Congress, Glasgow, online at ⟨http://66.102.1.104/scholar?hl=en&lr=&q=cache:RlmHxSN0UdkJ:www.see.ed.ac.uk/comp/pcsoft/apps/shire/.n/The-School/RIs/ies/Conf_proceedings/WREC_X_2008/DATA/M26.PDF+Wave+Energy+Technology+Review:+Application+of+the+Learning+Curve+Concept+1970+%E2%80%93+1999⟩.

Neij, L., 1997. Use of experience curves to analyse the prospects for diffusion and adoption of renewable energy. Energy Policy 23 (13), 1099–1107.

Neij, L., 1999. Cost dynamics of wind power. Energy 24, 375–389.
Neij, L., 2008. Cost development of future technologies for power generation – a study based on experience curves and complementary bottom-up assessments. Energy Policy 36, 2200–2211.
Nuclear Energy Agency, 1983. Projected costs of generating electricity. Nuclear Energy Agency.
Nuclear Energy Agency, 1986. Projected costs of generating electricity. Nuclear Energy Agency.
Nuclear Energy Agency and International Energy Agency, 1989. Projected costs of generating electricity from power stations for commissioning in the period 1995–2000. Nuclear Energy Agency and International Energy Agency.
Nuclear Energy Agency and International Energy Agency, 1998. Projected costs of generating electricity. Nuclear Energy Agency and International Energy Agency.
Nuclear Energy Agency and International Energy Agency, 2005. Projected costs of generating electricity. Nuclear Energy Agency and International Energy Agency, 16th March 2005.
Ofgem, 2008. Renewables Obligation: Annual Report 2006–2007, published by Ofgem, 4th March 2008, available online at 〈http://www.ofgem.gov.uk/Sustainability/Environmnt/RenewablObl/Documents1/Annual%20report%202006-07.pdf〉.
Ofgem, 2010. Renewables Obligation: Annual Report 2008–2009, published by Ofgem, 4th March 2008, available online at 〈http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?file=Annual%20Report%202008-09.pdf&refer=Sustainability/Environment/RenewablObl〉.
Olsen, J.A., 1993. On what basis should health be discounted? Journal of Health Economics 12, 39–53.
Oxera, 2005. What is the potential for commercially viable renewable generation technologies?, interim report prepared for the Department of Trade and Industry, January 2005.
PB Power, 2006. Powering the nation: a review of the costs of generating electricity.
Previsic, M., Bedard, R., Hagerman, G., Siddiqui, O. 2004. System level design, performance and costs for San Francisco Pelamis Offshore Wave Power Plant. Report by Global Energy Partners, Electricity Innovation Institute and EPRI.
Redpoint Energy Ltd, 2008. Implementation of EU 2020 Renewable Target in the UK Electricity Sector: Renewable Support Schemes. A report for the Department of Business, Enterprise and Regulatory Reform, June 2008.
Renewables Obligation (Amendment) Order, 2009a. The Stationary Office, S.I. 2010, No. 829.
Renewables Obligation Order, 2009b. The Stationary Office, S.I. 2009, No. 785.
Renewables Obligation (Northern Ireland) Amendment Order, 2010a. The Stationary Office, S.R. 2009, No. 785.
Renewables Obligation (Northern Ireland) Order, 2009c. The Stationary Office, S.R. 2009, No. 154.
Renewables Obligation (Scotland) Amendment Order, 2010b. The Stationary Office, Draft S.I. 2009.
Renewables Obligation (Scotland) Order, 2009d. The Stationary Office, S.I. 2009, No. 140.
Roth, I.F., Ambs, L.L., 2004. Incorporating externalities into a full cost approach to electric power generation life-cycle costing. Energy 29, 2125–2144.
Royal Academy of Engineering, 2004. The Cost of Generating Electricity. PB Power for the Royal Academy of Engineering.
Scottish Government, 2008. Renewables Obligation (Scotland) Introduction of Banding, Statutory Consultation, September 2008, available online at 〈http://www.scotland.gov.uk/Resource/Doc/917/0065773.pdf〉.
Science and Technology Policy Research (SPRU) and NERA Economic Consulting, 2006. Paper 4: The economics of nuclear power, an evidence-based report for the Sustainable Development Commission investigation into The role of nuclear power in a low carbon economy, March 2006, available online at 〈http://www.sd-commission.org.uk/publications/downloads/Nuclear-paper4-Economics.pdf〉.
Sinclair Knight Merz, 2008. Growth scenarios for UK renewables generation and implications for future developments and operation of electricity networks, report for Department of Business Enterprise and Regulatory Reform, June 2008, BERR Publication URN 08/1021.
Sinden, D., 2007. Characteristics of the UK wind resource: long-term patterns and relationship to electricity demand. Energy Policy 35 (1), 112–127.
Skea, J., Anderson, D., Green, T., Gross, R., Heptonstall, P., Leach, M., 2008. Intermittent renewable generation and the cost of maintaining power system reliability. IET Generation, Transmission & Distribution 2 (2), 82–89.
SQW Energy, Redfield Consulting, Cambridge Economic Policy Associates and Econnect, 2008. Modelling changes to the Renewables Obligation, report commissioned by the Scottish Government, published December 2008, available online at 〈http://www.scotland.gov.uk/Resource/Doc/243011/0067613.pdf〉.
Stallard, T., Rothschild, R., Aggidis, G.A., 2008. A comparative approach to the economic modelling of a large-scale wave power scheme. European Journal of Operational Research 185, 884–898.
Styles, D, Jones, M.B., 2007. Current and future financial competitiveness of electricity and heat from energy crops: a case study from Ireland. Energy Policy 35, 4355–4367.
Taylor, G.W., 2007. Letter to California Energy Commissioners, June 22nd 2007, available online at 〈http://www.energy.ca.gov/2007_energypolicy/documents/2007-06-12_workshop/comments/Ocean_Power_Tech_Wave_Power_Costs.pdf〉.
Winskell, M., Markusson, N., Jeffrey, H., Jablonski, S., Candelise, C., Ward, D., Howarth, P., 2008. Technology change and energy systems: learning pathways for future sources of energy, draft report from UK Energy Research Centre research programme on Energy Technology Learning Rates and Learning Effects, online at 〈http://www.ukerc.ac.uk/Downloads/PDF/T/Technology_change.pdf〉.