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Pricing offshore wind power

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ABSTRACT

Offshore wind offers a very large clean power resource, but electricity from the first US offshore wind contracts is costlier than current regional wholesale electricity prices. To better understand the factors that drive these costs, we develop a pro-forma cash flow model to calculate two results: the levelized cost of energy, and the breakeven price required for financial viability. We then determine input values based on our analysis of capital markets and of 35 operating and planned projects in Europe, China, and the United States. The model is run for a range of inputs appropriate to US policies, electricity markets, and capital markets to assess how changes in policy incentives, project inputs, and financial structure affect the breakeven price of offshore wind power. The model and documentation are made publicly available.

1. Introduction

As the largest renewable energy resource for many coastal states, offshore wind power offers both substantial economic benefits and significant reductions in CO_2 and other harmful pollutants. The private cost of offshore wind power is lower than that of most other new renewable energy technologies, though it is more costly than land-based wind power and most conventional generating technologies. Policymakers in some countries, notably the UK, have prioritized large-scale deployment of offshore wind ahead of other energy sources due to these advantages. Policymakers in other countries, notably China, plan to expand capacity of offshore wind power as part of a broad approach to expanding energy supplies. The result is the emergence of offshore wind as an important source of new energy: in Europe in 2010, more than 1 GW[1] of new offshore wind capacity came on-line, representing new capital investment of more than $4 billion; global cumulative capacity was 2.4 GW, with an additional 4 GW under construction (Moccia et al., 2010).

Many policy decisions by government and investment decisions by the private sector depend on proper analysis of costs over time. This information is also useful for citizens to understand the cost consequences of policy choices. Measures of the cost per unit of energy are used to facilitate comparison among different technologies and with prevailing market prices. We use two such measures in this analysis: the Levelized Cost of Energy (LCOE), a measure of the total financial cost of produced electricity without consideration of policy or financial structures; and the Breakeven Price, which is the minimum electricity sale price required for financial viability given a particular policy, tax, and purchase contract structure.

Some privately held price and cost models for offshore wind have been developed, but they are not in the public domain and therefore not accessible for analysis, validation, or refinement. This is unfortunate, as the insights that one could draw from those cost models would be of value for addressing important business decisions and policy questions, such as the following:

- What measures are required to spur development of offshore wind plants?
- Which policies are more likely to bring down energy costs?
- If a cost-reduction program is to be designed, which components are likely to have the greatest effect in reducing the cost of energy?
- What is the impact of changes to financial structures on the Breakeven Price for a given project?

We develop and describe here a pro-forma cash flow financial model to calculate the cost per unit of energy generated from offshore wind. We develop ranges for the model's inputs based on capital and operating costs from actual and planned projects, cost projections from the literature, and analysis of capital markets. We present results for various scenarios and financial structures and as a sensitivity analysis. We contribute our discounted cash-flow spreadsheet model to the public domain at the time of this publication so that analysts can alter input values consistent with a specific policy and commercial environment, and examine the

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[1] In 2010, the following projects were fully commissioned, representing 1235 MW of capacity: Alpha Ventus, Belwind, Baltic I, Donghai Bridge, Gunfleet Sands, Rødsand II, Robin Rigg, and Thanet.

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effect on the Breakeven Price. To improve comprehension of this discussion, details that do not have significant effects on results and that may be conceptually distracting are documented in the accompanying spreadsheet, but not in the text of this article.

2. Method

2.1. Analytical approach

Methods for calculating the LCOE vary by application and definition: some, like ours, use cash flow analyses (Salvadores and Keppler, 2010), while others use formulas adapted from cash flow calculations (NREL, 2010); some use physical depreciation over the life of the plant, while others use tax depreciation dictated by federal policy (EIA, 2006); some include policy incentives (Cory and Schwabe, 2010); some are expressed in real currency, others in nominal currency (Ruegg and Short, 2007); and some model the detailed financial structure of a project (NREL, 2001; Harper et al., 2007). In the case of offshore wind, each of these choices has a significant impact on results. In this study, we take LCOE to relate only to the physical characteristics of a plant, useful for comparing different technologies under any policy or financial structure. Policy incentives are excluded, depreciation is over the life of the plant, there is no capital structure apart from the discount rate, and the hypothetical sale price is constant over time (in real terms).

While LCOE is useful for comparing among technologies, it does not reveal revenues required to finance a project using a particular technology. Thus, we also calculate a hypothetical energy sale price, the "Breakeven Price" (BP), which we define as the price that provides a sufficient return to attract investment under the conditions a typical developer or financier would encounter in particular market and policy conditions (here, we are using conditions in the United States). As with LCOE, the Breakeven Price reflects lifetime costs, but unlike LCOE, it also includes non-physical parameters such as financial structure, tax policy, and contractual price escalation. Breakeven Price is representative of the share of project cost borne by the electricity buyer; LCOE, by contrast, represents the total financial cost of the project, and may be paid for by parties other than the electricity buyer, such as other ratepayers or taxpayers.

The term "Breakeven Price" is not used consistently in the literature: its use in agricultural analysis is similar to ours, albeit without the emphasis we place on inclusion of policy and financial structure (Khanna et al., 2008), and likewise with some energy analyses (Young, 2003; Zaelke, 2009). However, this term has also been used occasionally to refer to other concepts (Xing and Wu, 2003; Tokimatsu et al., 2002; Strauss, 1983).

2.2. Calculation of LCOE and BP

We calculate LCOE by evaluating (1) energy production and (2) costs from construction and operations. A list of cost cash flows from each year of the project, including construction and operation, is compiled in nominal values, and its Net Present Value (NPV) is calculated using a nominal interest rate. (Nominal cash flows are expressed as values from the year of the flow, unadjusted for inflation; similarly, the nominal interest rate is unadjusted for inflation. The counterparts to nominal values, real values, are adjusted for inflation). The cash flow does not include debt payments or dividends to equity investors, as these are accounted for in the discount rate used in the net present value calculation. Next, the flow of electrical energy production (at the point of interconnection with the grid) is determined for each year of the project, and it too is discounted. We then calculate a dollar value for each unit of energy produced that is constant (in real terms) over the life of the project such that the net present value of energy revenues equals the net present value of costs. (Real values are expressed in money from a particular year, so a price that is constant in real terms escalates at the rate of inflation in nominal terms.) More simply, LCOE can be thought of as the NPV of costs (in units of currency) divided by the NPV of energy production (in units of energy). A simplified example calculation is shown in Table 1a and 1b.

While LCOE and Breakeven Price each have many inputs, they share four principal determining factors:

- Capital Expenditure (CAPEX): the cost to buy and build the power plant.
- Operating Expenditure (OPEX): ongoing costs to operate and maintain the plant.
- Discount rate: the return on investment required to attract project investors.
- Net capacity factor: the fraction of average power generated over the long-term divided by nameplate power.

Breakeven Price has three further main parameters:

- Tax and policy inputs as applicable to the scenario.
- Price escalator: the amount the price increases each year, determined by the power purchase contract.
- Financial structure: debt term, term of power purchase agreement, etc.

We calculate Breakeven Price in a similar way to LCOE, but with these differences in costs and benefits based on US policies: (1) depreciation is according to Internal Revenue Service tax

Table 1a
Input parameters (in \$2010) for the example LCOE calculation shown in Table 1b, below.

Build cost	Operating cost	Discount rate for NPV	Plant capacity	Capacity factor	Inflation
\$1b	\$35/MWh	10% per year	235 MW	36%	2%

Table 1b
A rudimentary 20-year LCOE calculation in nominal terms (neglecting taxes), with the resulting LCOE in terms of year 2010 dollars. Note the escalating costs representing increasing wages and material costs due to inflation, as well as the escalating revenue reflecting the fact that the energy value, fixed in real terms, escalates at the rate of inflation in nominal terms.

Year	NPV (2010)	2011	2012–2016	2017–2021	2022–2026	2027–2031
Cost (\$m)	**\$1132**	\$1020	\$146	\$161	\$178	\$197
Energy (TWh)	–	0	3.7	3.7	3.7	3.7
\$2010 per MWh such that NPV of energy revenue equals NPV of costs: ***\$194***						
Revenue (\$m)	**\$1132**	0	\$809	\$893	\$986	\$1089

schedules, not physical lifetime. In this case, we use the MACRS 5-year schedule applicable to wind energy projects; (2) the Production Tax Credit (PTC), Investment Tax Credit (ITC), or Section 1603 cash grant incentives for renewable energy production are included as applicable to the case in question; (3) the hypothetical contracted energy sale price is escalated at a specified rate over a given term, whereas the nominal LCOE increases exactly at the rate of inflation; (4) cash flows to and from debt investors given a specified payment structure are included as applicable to the case; (5) in some cases, values for the discount rate used in the Breakeven Price calculation reflect equity investors only, whereas values for the discount rate used in the LCOE model are a weighted average of required returns on debt and equity. (We discuss debt and equity in detail in Section 5).

2.3. Determination of cost parameters

Values were determined for the above parameters by a review of public documents on actual projects, supplemented by interviews with offshore wind developers and other industry leaders. Cost values were converted to US dollars using the European Central Bank exchange rate from the year costs were incurred (ECB, 2010), and then converted to 2010 US dollars using inflation figures from the Bureau of Labor Statistics (BLS, 2010). Unless otherwise specified, all dollar amounts in this document are considered to be in terms of 2010 dollars.

Given development timelines currently projected by the US federal leasing body (the Bureau of Ocean Energy Management, Regulation and Enforcement or BOEMRE), only a single plant will start construction in federal waters (generally those more than three nautical miles from an oceanic coast) in the near term (DOE, 2010a; BOEMRE, 2010). Thus, the timeline under consideration is primarily 2015 and later.

2.4. Scope and limitations

We examine only internal costs, as externalities are analytically different from internal costs, and methodologies for their calculation vary considerably (Schleisner, 1999). Power generated by fossil fuels, such as coal and natural gas, emit a harmful mix of gases and particulates as a byproduct of generation, and thus have substantially higher external costs than offshore wind power. The market price of power in the United States does not account for the majority of these costs, which are borne elsewhere, notably in the cost of healthcare (National Research Council, 2009; European Commission, 2003; Army Corps of Engineers, 2009) and the future value of a stable climate (Sovacool, 2009). The omission of externalities from this analysis makes the cost premium of offshore wind power relative to conventional power seem significantly higher than it actually is.

To estimate capital cost, we review the total capital costs of actual offshore wind projects. Basing costs on actual projects has the substantial advantage of realism. However, our approach lacks the ability to decompose capital cost into individual components, for example by installation versus equipment, or materials versus labor. Further disaggregation of capital cost would be useful but is beyond the scope of this paper. In addition, the results of a component-based CAPEX analysis will generally be different from our analysis, as it may not take into account the effect of market pressures on prices of assemblies of components. For results of a disaggregated CAPEX model, see Greenacre et al. (2010).

Long-term cash-flow models can, in general, be limited by the accuracy of projections over decades. Renewable energy projects, however, with heavily front-loaded costs, meteorological predictability of long-term production, and long-term agreements fixing electric power rates, allow for relatively accurate cash-flow projections.

This cash-flow model functions on an *after-tax* basis: it discounts after-tax values using an adjusted after-tax discount rate. This treatment implies that tax benefits such as depreciation or tax credits are fully monetized by the owner. This assumption breaks down in the event that the owner has insufficient income to take advantage of the tax benefits. There is a risk that we model some benefits that would in reality have to be deferred, especially with respect to accelerated depreciation in a scenario with no tax equity investors. Tax equity investors are also exposed to this risk, but that is accommodated by assuming a higher cost of capital for such investors (discussed later).

The cost parameters discussed below are derived from actual values representing marginal changes in demand for the required products, such as steel, rare-earth metals, large bearings, and generators. However, given the potential scale of growth, it is possible that the offshore wind sector could comprise a significant or even majority share of some of these markets, thus changing the underlying demand economics and potentially raising prices. Conversely, manufacturing and construction at the scale planned for the UK, and possible for the United States East Coast, would lead to industrialization of these process and economies of scale. Thus, the cost assumptions discussed below apply best to projects in the offshore wind industry in the near- to mid-term.

We do not explicitly model the effect of distance from shore, turbine type, and water depth on cost. However, limits on these parameters are implicit in the data used to derive the input ranges, and thus these ranges apply best to hypothetical wind plants that are broadly similar to our data set: namely, plants that use conventional technology (including monopile, gravity base, and jacket foundations), have sites with similar metocean and seabed conditions, are in no more than 30 m of water, and are at most 46 km from shore. These conditions hold for most of the sites under consideration for offshore wind development in the Atlantic Ocean offshore of the United States.

Exchange rates do not necessarily reflect relative prices between countries in any given commodity, nor do they reflect relative costs of local components such as labor. Some authors use purchasing power parity measures to adjust for this (Du and Parsons, 2009), while Hagerman et al. (2010) advocate bottom-up cost estimates that take account of labor cost differences. Both of these approaches would result in lower costs estimates for US projects relative to European ones. While we acknowledge the complexity of international cost comparisons, our simpler approach allows a more streamlined and straightforward analysis, which is valuable especially given the inherently high uncertainty in these ranges.

2.5. Level of detail

Our model is more detailed than a simple formula, in that we list the cash flows in each year and can model more complex investment structures. However, it is less detailed than other models: we do not specify the proportion of investment that is eligible for accelerated depreciation, for example, nor do we model the impact of state taxes, cash reserves for debt, or operating capital requirements. In general, we omit details that have less than a roughly 2% impact on the result.

3. Costs

3.1. Capital expenditures

Capital expenditure is taken to mean an expenditure whose benefit extends beyond one year, and refers here to the costs associated with building and installing the plant. Capital Expenditures (or CAPEX) mostly comprise material and labor costs for turbines,

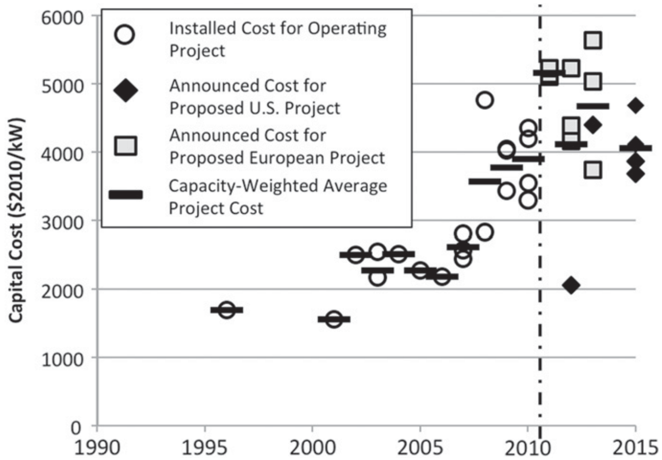

Fig. 1. CAPEX/kw for European and US projects. Points to the right of the dotted line are planned. CAPEX shows a marked increase from 2007 through 2010, as discussed in text.

foundations, and inter-array cabling, but also include construction financing, development costs, and operating capital. Substation and high-voltage export cable costs, which equate to less than 20% of CAPEX (Krohn et al., 2009), are generally but not always included in reports of actual costs. Given the already-wide range of values in CAPEX and the difficulty of obtaining publicly verifiable cost breakdowns, no differentiation is made between projects that include versus exclude these interconnection costs.

We compiled CAPEX data from various sources including press releases and trade publications and converted them to 2010 US dollars as described in Section 2.3. Fig. 1 shows installed capital cost per kW for projects installed between 1990 and 2010[2] and projects planned for installation between 2011 and 2015. For more on data sources, see Musial and Ram (2010). The sharp increase in CAPEX beginning in 2007—also observed in the land-based wind industry and in the power industry overall (Milborrow, 2008)—has been extensively studied, with results implicating a confluence of factors including the following (Greenacre et al., 2010; Hagerman et al., 2010; Isabel Blanco, 2009; BWEA and Garrad-Hassan, 2009):

- Growing demand and limited supply of wind turbines due to:
  - Rapid growth in global demand for land-based wind and a resulting drop in supply for the offshore segment.
  - Policy-driven growth in demand for offshore wind power plants.
- Changes in general global and regional macroeconomic drivers such as labor costs, commodity prices, and currency exchange rate fluctuations.
- Corporate changes at the two major offshore turbine suppliers.
- Constrained port and vessel availability.
- Increased understanding of the technical risks associated with manufacturing offshore wind turbines and developing offshore wind projects (e.g., design robustness, logistics, and reliability).
- Increasing cost of siting projects in deeper water and farther from shore.

Easing of many of the general macroeconomic factors between 2008 and 2010 led to predictions that capital costs for land-based wind would fall (Bolinger, 2009; Goodwin, 2009), however, costs have risen slightly instead (Wiser and Bolinger, 2010). This suggests that general macroeconomic drivers like commodity prices play less of a role in driving CAPEX for on-land wind turbines. This suggestion is supported for the offshore industry in BWEA and Garrad-Hassan (2009), which concludes that wind-industry-specific factors like supply and demand of wind turbines, vessel limitations, local labor rates, and particular corporate developments play more of a role than general macroeconomic factors. However, the opposite view is taken in Greenacre et al. (2010), which concludes that commodity and overall labor prices are more important. Recent evidence from the UK suggests that costs may be leveling off (Greenacre et al., 2010).

CAPEX values for completed and running commercial-scale plants have ranged between $1500 and $4750 perkW, though contracted future costs and recent actual costs and are in a narrower band between $3500 and $5750 per kW, as shown in Fig. 1. Use of this narrower range is in line with recent medium-term projections for UK projects (Table 2). However, it is higher than certain international forecasts, which suggests there is some risk that our range is high.

3.2. Operating expenditures

Operating Expenditures (or OPEX) for US projects apply to both the wind farm and the interconnection infrastructure, and includes administrative costs, operations and maintenance costs (“O&M”), insurance, taxes, and payments for rent, royalties, and rights of way. OPEX does not generally include warrantied capital repair costs, such as those used to remedy the serial design defects common in the middle 2000s. OPEX values have a high uncertainty due to lack of published data, and will tend to increase as equipment ages.

One source of data is from Round 1 UK projects, which were required to disclose such costs. They report values ranging from $12 to $36/MWh, with an overall capacity-weighted average of $19/MWh (Fig. 2). These figures are dominated by service

Table 2
CAPEX projections for offshore wind power plants, by source.

Source	*CAPEX (USD2010/kW)*
BWEA and Garrad-Hassan (2009)	$3450–$5850/kW
Greenacre et al. (2010)	$4500–$5250/kW
Ernst and Young (2009)	$4500/kW
KPMG (2010)	$4400–$5000/kW
Krohn et al. (2009)	$2000–$2700/kW

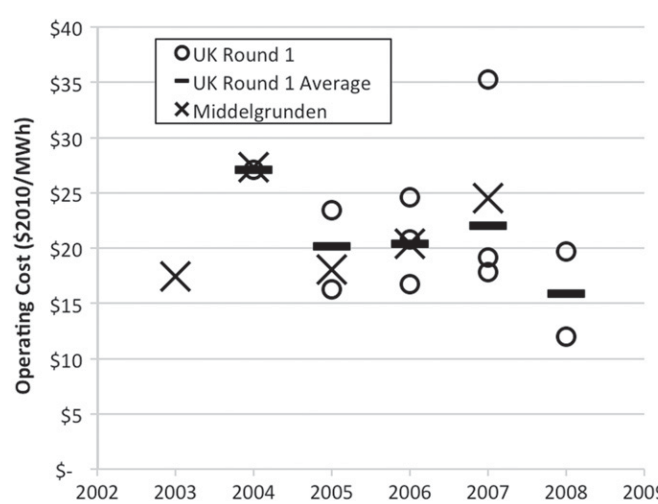

Fig. 2. OPEX in selected projects over time.

[2] We exclude Alpha Ventus and Beatrice, which are early demonstrations of new technology that may not be representative of the (generally larger) commercial projects using the mature technology.

contract costs in which the turbine manufacturer, in all of these cases Vestas, took the risk of higher-than-expected operating costs. As it happens, these projects all required the costly replacement of a significant proportion of gearboxes, generators, and transformers. Perhaps these early OPEX figures reflect an initial underestimation of operating costs and risks, as ensuing estimates have largely been significantly higher (Table 3). Another source of data is from the pioneering project Middelgrunden, with reports of actual O&M in a range $17–$27/MWh (Svenson and Larsen, 2008). However, this project is unusually close to shore and has mild metocean conditions. It is also useful to compare these estimates to average land-based O&M costs in the United States of about $10/MWh (Wiser and Bolinger, 2010).

Long-term operations and maintenance costs are relatively uncertain by comparison with CAPEX; to minimize the risk of underestimating the cost of offshore wind power, we use the relatively higher range of OPEX estimates represented by KPMG: $27–$48/MWh.

4. Revenues

4.1. Energy production

To determine a range for the energy production from typical offshore wind turbines sited in our study area, we compare three regions of the East Coast. The wind speed is calculated from National Buoy Data Center readings, extrapolated to hub height and averaged over a five year period. The capacity factor is calculated from hourly wind speeds against the power curve of a 5 MW turbine, both documented in an earlier publication ((Kempton et al., 2010); Supporting Information Table S2). For simplicity, we assume that wind speed is the only parameter that varies by region, neglecting potentially significant differences in OPEX, CAPEX, and availability.

Thus, we derive gross capacity factors ranging from 32% to 43% (Table 4). For reference, these values from our study area compare with values from the same study of 42% in the Gulf of Maine and 28% off the Florida Keys. These are mean estimates: we expect that half the time capacity factors will be higher, and half the time lower (sometimes called P50 estimates).[3]

Figures for losses at the turbine due to the wake effect from neighboring turbines range, for typical projects, from 6.6% at Egmond aan Zee (Curvers and van der Werff, 2009) to 12.4% at Horns Rev, (Sørensen et al., 2006). Though values as high as 23% are reported for plants with atypically close turbine spacing such as Lillgrund (Dahlberg and Thor, 2009), we assume the range of 6.6–12.4%. Cable losses to land can account for an additional 1–3% (Negra et al., 2006). Taking the full range of each of these loss parameters as well as the gross capacity factor yields a net capacity factor ranging from 27% to 40%, as shown in Table 4.

The term *technical availability* refers to the fraction of time that the plant is available to produce energy (International Energy Agency, 1994). When considering availability, it is important to distinguish between *system availability (*also called *wind farm availability)* and *turbine availability* (also called *commercial availability)*, definitions for which we borrow from Harman (2008). System availability is the proportion of time that the entire plant is capable of generating and delivering to the grid, and it "…counts *all* down-time against availability regardless of the cause." Turbine availability, meanwhile, is concerned with the definition of availability in the warranty contract with the turbine manufacturer, and it generally excludes not just downtime unrelated to turbines but also turbine downtime due to weather, transport, and planned maintenance. Note that these terms are not entirely standardized, and that some use *technical availability* to refer to both turbine availability and system availability (International Energy Agency, 1994; Küver, 2009), while others use technical availability to refer only to system availability (Feng et al., 2010).

Reported system availability of offshore wind turbine ranges from 99% at Middelgrunden (Svenson and Larsen, 2008) to much lower at plants undergoing short-term retrofits. Limited data was found on turbine availability: 94–97.3% for two years at Samsø, 96.5% for one year at Horns Rev (Clausen and Morthorst, 2005), 95.5% for one year at Thornton Bank (REpower Systems AG, 2010), and 96.5% for six years at Nysted (Emsholm, 2009). A direct comparison between turbine and system availability was found for two plants: the first eight months at Nysted (98.4% vs. 97.1%) (Bakker, 2010), and the first two years at Prinses Amalia ($\sim$97.0% vs. $\sim$95.7%) (Volund et al., 2004), reflecting non-turbine downtime of $\sim$1.3% in both cases.

Long-term offshore system availability is widely expected to reach the 97% level achieved on land. The foregoing data suggests that such levels are within reach, especially given that land-based plants show a teething period in the first two years of operation in which availability is about 2% lower (Harman, 2008). Thus, for a long-term figure we use 97%. Note that this is higher than an estimate used by PriceWaterhouseCoopers (Küver, 2009) and others, and neglects the poor experiences shown in the UK Round I plants. Moreover, turbine vendors have set minimum availability guarantees at the 90% level (Hoefakker, 2010) (Guillet, 2007). Still, we think the data supports the more optimistic estimate of 97% for the 2015–2035 horizon.

Table 3
OPEX projections. Where necessary, calculations have been made to transform values into USD2010/MWh using prudent assumptions, including for capacity factor, CAPEX, currency exchange rates, and inflation measures, as appropriate. Projections marked *IEA* are from the International Energy Agency (IEA) report *Projected Costs of Generating* Electricity (Salvadores and Keppler, 2010). IEA projections from countries without offshore wind farms were excluded.

Source	*Value (USD2010/MWh)*
Ernst and Young (2009)	$50
KPMG (2010)	$27–$48
ECN (Lako, 2010)	$40–$66
EWEA (Krohn et al., 2009)	$17
EWEA (Morthorst et al., 2009)	$21
Germany (IEA)	$46
Netherlands (IEA)	$11
Belgium (IEA)	$54
EURELECTRIC (IEA)	$43
China (IEA)	$20

Table 4
Regional mean wind speed at hub height and resulting capacity factor. Wind speed and gross capacity factor are from (Kempton et al., 2010).

Region	Mean wind speed (m/s)	Gross capacity factor (%)	Net capacity factor (%)
Northeast US (Massachusetts)	8.64	43	37–40
Mid-Atlantic US (Delaware)	8.14	39	33–36
Southeast US (Georgia)	7.38	32	27–30

[3] This financial model uses required returns for investors. While *expected* returns are based on P50 wind production, required returns may be based on safer estimates. For example, some banks require production estimates with 90% or 99% certainty (called P90 and P99), rather than P50, for determining safe debt levels (PREF, 2010b; KPMG, 2010). Tax equity returns are based on actual production, which by definition should be close to expected performance. In the Capital Asset Pricing Model, the required equity return is based on expected return.

4.2. Non-energy revenue

Energy sales are not the only potential source of revenue for offshore wind power plants; depending on the market, other sources can include capacity, reactive power, black-start capability, fast-response reserves, and Renewable Energy Credits (RECs). Revenues from reactive power, black-start capability, and reserves are not significant, and so they are not considered. Revenues from capacity and RECs, however, are both significant.

State Renewable Portfolio Standard laws require electric utilities to buy RECs from renewable energy generators such as offshore wind power plants. These REC sales afford a significant additional source of revenue that is ultimately provided by state electricity consumers. REC prices depend strongly on the details of state legislation and rulemaking, and are also often volatile in time; for this reason we do not explicitly model the value of RECs. The Breakeven Price can thus be considered to represent the value of both energy and RECs—the value of RECs does not affect the Breakeven Price so defined.

Due to the inelasticity of electricity demand to hour-scale price changes, many power markets, in addition to trading energy, trade the ability to deliver further energy during times of critical peak load as a separate product called "capacity". We use the value used by the US Regional Transmission Operator PJM of 13% of wind project nameplate capacity as a low estimate of the capacity credit of an offshore wind farm (PJM, 2010b). The long-term capacity price is a user-defined parameter of the model, and as the capacity price rises, the Breakeven Price falls. We use $200/MW-day as representative of the capacity price over the life of the project, given the results of auctions between 2008 and 2010, which for coastal regions in the PJM regional transmission operator ranged between $110 and $245/MW-day (PJM, 2010a). This is in line with the long-term contracted price for capacity in the Bluewater Wind PPA of $207/MW-day in 2010 dollars (Bluewater, 2008).

5. Discount rate

5.1. Definitions

Cash flows n periods in the future (future value or FV) are worth less than cash flows today (present value or PV), and the discount rate r is used to make the comparison, according to the following: (Brealey et al., 2010):

$$PV = FV * (1+r)^{-n}$$

Net Present Value (NPV) is the sum of present values calculated for many periods, in this model annually. Both LCOE and Breakeven Price are calculated such that the NPV of benefits equals the NPV of costs

$$\sum_{n=0}^{N} C_n * (1+r)^{-n} = \sum_{n=0}^{N} (AEP_n * P_n + B_n) * (1+r)^{-n}$$

where for each period n, C_n is total cash expenditures (including debt service payments where appropriate), AEP_n is energy production, B_n represents other benefits such as tax benefits, capacity payments, etc., and P_n (which is the resulting LCOE or BP) is the hypothetical energy price in that period.

The discount rate r reflects the risk-adjusted opportunity-cost of capital. Many analysts assume a single "social resource cost" as the discount rate for any technology in their LCOE calculation, in order to compare technologies without influence from what may be seen as judgments from financial markets that are irrelevant to the technologies (Salvadores and Keppler, 2010). This may be appropriate for calculating LCOE, but for Breakeven Price an understanding of market rates is needed. Thus, here we prefer to use the market-based cost of capital as a basis for our discount rate, even for our LCOE calculation. Cost of capital is a measure of the equivalent constant annual return required by capital markets for investment in a project; it varies according to financial structure and risk.

There are generally two types of capital: debt and equity. Debt securities usually promise fixed payments over a predetermined term, while equity securities give their holders an indefinite claim to residual profits; debt represents a loan, and equity represents an ownership stake. (See PREF, (2009a)) for a discussion of the role of debt and equity in renewable energy projects.) The required rate of return is the minimum rate of return required by investors to compensate them for the riskiness of the investment. The required return on debt is generally lower than the required return on equity, as the former has lower risk due to its fixed payment schedule, priority right to free cash flows, and other measures designed to reduce risk. Detailed models exist to predict the required rates of return for both debt and equity, however, we limit ourselves here to a discussion of market data for investments in the United States and Europe that are directly analogous to offshore wind farms.

Rates are also sensitive to project-specific structures: the allocation of risk between different project investors; transfer of risk to corporate-level investors not involved in the project; purchase of risk transfer through insurance or service guarantees; and transfer of risk to governments through loan guarantees, capital grants, or outright ownership. To the extent that we model government loan guarantees and typical insurance costs these effects are accounted for; however, we do not model any more complex variations on risk allocation, such as unusually comprehensive turbine warranties or novel insurance arrangements.

In corporate finance, both debt and equity are raised at the corporate level and are allocated by the management of the corporation among the firm's investment opportunities. The corporation as a whole has a Weighted-Average Cost of Capital (or WACC) that is the weighted average of the required returns on the firm's debt and equity as determined by the market. Although each of the firm's investments has its own level of risk and ostensible required return, markets analyze the combination of these to determine the WACC. This rate can be taken as the minimum rate of return required to fund a project. However, the risk profile of a project, and therefore the required return, can vary from that of the corporate sponsor, and so this approach is limited.

In project finance, by contrast, money is raised for each project individually, often using debt and equity from individual banks or from small groups of banks instead of from public bond and stock markets. Because project finance investments apply exclusively to a given project, they are a good measure of the actual cost of capital given the unique risk profile of that project. So while corporate finance may make up the majority of the funding mechanisms for an industry (such as offshore wind in Europe), it is the project finance deals that provide the best insights with respect to the effective cost of capital and hence the discount rate. Thus, even when modeling corporate finance, we do not use the cost of capital of any corporation as a discount rate; instead we use the number (calculated in Section 5.6 below) that is consistent with debt and equity rates for project-financed offshore wind projects.

A discussion of capital markets as we write in 2010 requires a note on the timing and impact of the financial crisis that began in 2007. The first governmental interventions were in August 2007 (Duncan, 2007), and the bankruptcy of Lehman Brothers in September 2008 triggered the changes in the financial industry now referred to as "the financial crisis" (Dougherty and

Table 5
Debt terms for project-financed offshore wind plants. Three of the four projects rely on both debt that is not covered by a guarantee (*Uncovered* rows) and government-guaranteed debt (in the *Guaranteed* rows).

	Prinses Amalia	Thornton I	Belwind	Thornton II
Uncovered	€150 m	€111 m	€121.5 m	€338 m
Price/rate	200 bp/6.1%	120 bp/6.8%	350 bp/7.5%	Unknown
Guaranteed	€69 m	–	€361 m	€575 m
Price/rate	150 bp/5.6%	–	250 bp/6.5%	190 bp/5.0%
Term	11 years	15 years	15 years	18 years
Close	October 2006	May 2007	July 2009	November 2010
Risk-free rate[a]	4.1%	4.6%	4.0%	3.1%
Reference	(Ellis, 2006)	(Project Finance Magazine, 2008)	(Project Finance Magazine, 2010a)	(Project Finance Magazine, 2010b)

[a] The risk-free rate is the market rate at the time of financial close on 3-month EURIBOR interest-rate swaps with the same term as the debt.

Werdigier, 2008). The financial crisis led to the passage of the American Recovery and Reinvestment Act (ARRA) in February 2009, changing the structure of policy incentives for wind power. It also ultimately led to a drop in the risk-free rate, so that despite the rise in risk premiums, US and European debt rates for wind projects remained broadly the same as they were prior to the crisis (Guillet, 2009; Hennessy, 2010). However, the structure of post-crisis deals is different, with more emphasis on conservative revenue projections and higher reserves, so the total cost of capital has in fact been higher post-crisis.

5.2. *Debt and tax equity*

In the United States, most land-based wind plants have been project financed using a unique type of capital called *tax equity* (PREF, 2010b; Harper et al., 2007). Tax equity investors receive the tax benefits, namely accelerated depreciation and tax credits, which have been the dominant federal policy incentive for renewables in the United States. The US Internal Revenue Service requires that the recipient of tax benefits be an owner of the project, and in that sense tax equity investors are "owners". But in other senses they are lenders: tax equity is similar to debt in that it has a fixed term during which the majority of the payments are made, and a rate of return that is (nearly) contractually fixed. It is also arranged by many of the same banks that handle debt financing for European wind farms.

As of this writing and since the start of the financial crisis, tax equity markets have been largely frozen, and US wind plants have been supplementing tax equity investments with traditional debt and equity, together with the 30% US Treasury cash grant made available under ARRA. While this cash grant takes the place of tax credits, tax equity is still useful in order to monetize accelerated depreciation. Bloomberg New Energy Finance reports that debt rates for such projects have a 2.5% premium over the risk-free rate (discussed below), for a total of around 6.5% in late 2010 (Hennessy, 2010). A 2010 survey of stakeholders in land-based wind projects in the US shows all-in debt rates ranging from 5.5% to 8.5% (Mendelsohn, 2010c) (all-in debt rates include transaction costs, which we include in our estimate of the cost of debt and hence do not explicitly model).

In project-finance parlance, debt rates are quoted[4] in terms of two parameters: (1) the risk-free rate and (2) a premium. The risk-free rate (1) is based on market expectations about the behavior of a variable-rate index such as the European Interbank Offered Rate (EURIBOR) or the London Interbank Offered Rate (LIBOR). Though based on variable rates, project debt uses a fixed rate: by its nature the interest-rate swap market provides a fixed-price equivalent to a long-term stream of variable-rate cash flows. The premium (2) is called the "price", and has the units of "basis points" (bp), which are hundredths of a percent. Thus, for example, 11-year debt with a price of 200 bp has a stream of fixed cash flows with a rate of return that is equal to 2% plus the rate on 11-year interest rate swaps for LIBOR or EURIBOR.

Table 6
Characteristics of the two current DOE loan guarantee programs.

DOE loan program:	***1703***	***1705***
Expiration[a]	None	September. 30, 2011
Approx. loan volume[b]	\$51b	\$21b
Premium over risk-free rate	0.25[c]–1.75%	1.5[a]–3.0%[c]
Fraction of debt guaranteed[a]	100%	80%
Credit subsidy[d]	15% of loan	0

[a] (Mendelsohn, 2010a).
[b] (DOE, 2010b).
[c] 3.0% premium reported for Shepherds Flat wind farm (Green Energy Reporter, 2010).
[d] (Fisher, 2010).

Project debt for European land-based wind farms prior to the 2008 financial crisis was priced between 60 and 120 bp, while post-crisis rates in 2009 were 200–300 bp (Guillet, 2009). Several offshore wind farms were project-financed both before and after the crisis (Table 5). Prinses Amalia was the first such plant, and the uncovered debt shows an additional premium over land-based plants of about 100 bp. Thornton Bank on the other hand is priced within the range of pre-crisis land-based plants, and has no government guarantees at all. Belwind closed post-crisis, and has pricing at least 50 bp higher than land-based plants for the uncovered portion of its debt Table 6.

For the reasons noted above, we use project finance debt rates as the basis for the debt rates for both project-finance and balance-sheet finance cases. It bears emphasis that, for these European offshore wind plants, we only examine interest rates for the non-guaranteed portion of debt. For the purposes of this analysis, we also assume that the premium for offshore wind finance relative to land-based wind finance will be the same in the US market as it is in the European market. Surprisingly, in practice this premium is small, both for first-of-a-kind projects like Thornton Bank (first commercial-scale implementation of the REpower 5 M, first deep-water gravity base design, first project in Belgium), which has no premium, and more standard projects like Belwind (7th implementation of Vestas V90, standard monopile foundations), with a 100 bp premium. Thus, we use a relatively low value of 100 bp as indicative of the additional risk premium of offshore wind debt over land-based wind debt in the United States, even for the first US offshore projects. We further note that the debt rate for land-based wind plants in the United States is identical to the debt rate for land-based plants in Europe, and so

[4] Unless otherwise specified, debt rates are expressed as nominal, pre-tax rates.

we predict that debt rates for offshore wind in the two markets should be the same as well. Thus, either the rate for Belwind or the rate for land-based debt plus 100 bp should be a reasonable measure: these result in a rate of 7% and 6.5–9.5%, respectively, so we take the latter as the range for the all-in cost of debt, and use 8.0% as a the value for the first offshore projects in the US.

Tax equity is exposed to the additional risk that the investor will not have taxable income available to offset with the tax credits, thus, after the crisis, tax equity became scarce and increased in cost. Post-crisis tax equity rates for onshore wind range from 10.5% (Zaelke, 2009) to as high as 16.5% (PREF, 2009b; Mendelsohn, 2010b), though 12.5% may be a more typical upper value (Mendelsohn, 2010c). We use 12.5% as a conservative case and, since tax equity is similar to debt, we add the 100 bp offshore wind debt adder to arrive at a value of 13.5%. It bears repeating that this type of financing is likely to continue to be scarce in the near term (PREF, 2010a), making tax equity finance structures challenging.

5.3. Debt levels

A moderate level of debt increases returns to equity and lowers the overall cost of capital, because debt is a lower-cost form of capital compared to equity. However, the benefit of higher levels of debt is balanced against the increasing probability of financial distress and its associated costs. Therefore, sponsors will try to use as much debt financing as possible without incurring significant costs of financial distress. The limit on debt size is set by the level of conservativeness that debt investors require for estimates (e.g., P99 vs. P90 wind estimates), as well as the earnings buffer required in order to consider a project safe.

At sufficiently low levels of risk, debt levels may be high enough that costs to service that debt comprise as much as 90% of free cash flow. For riskier projects, debt levels will be lower and therefore the debt service will comprise a smaller proportion of free cash flow, allowing for solvency even with higher-volatility cash flows. As mentioned in the discussion on capacity factor, revenue projections are based on wind speed measurements, with higher confidence levels yielding lower revenue expectations. Thus, a financial analysis begins with wind data and buffer requirements to arrive at the amount of debt that is acceptable.

Without performing this analysis, it is still possible to get a sense for typical debt fractions: in European countries with long-term fixed-rate power purchase mandates, debt for land-based projects comprised as much as 90% of project capital prior to the crisis; afterwards, it dropped to 70–80% (Guillet, 2009). We use 64%, following the debt levels of current land-based projects in the US (Zaelke, 2009). As economic conditions improve and offshore wind projects become standardized, debt fractions could rise to as high as 80%.

5.4. Equity rate

In general, equity rates are modeled as a function of the macroeconomic risk-free rate (e.g., US Treasury Bonds, LIBOR, or EURIBOR) plus premiums for systematic risk (characteristic of the business sector as a whole), liquidity (length of time required to trade the investment), size of overall capitalization, and other factors (Pinto et al., 2010), with the selection of premiums varying among models. A complete determination of the equity rate for offshore wind projects in the United States would involve a detailed investigation of the relative advantages of different models and reasonable values for the factors, a study that is beyond the scope of this paper. Instead, we use the post-crisis onshore wind rate from Zaelke (2009) of 15% as a minimum. We then add a premium to arrive at 18% as a central value and 20% as a maximum. Although standard equity rates for such projects are not widely published, our range for offshore wind is probably substantially higher than rates for land-based projects in the US: stakeholders in several land-based wind projects in 2010 have reported required rates for standard equity as low as 6.5% and as high as 18.5% (Mendelsohn, 2010c). It is also commensurate with the 18% value used by the Massachusetts Attorney General with respect to the Cape Wind project (Mass, 2010). Finally, a Capital Asset Pricing Model study performed using data from the land-based US wind industry in 1993, a time when the land-based industry had a risk profile that is perhaps similar to the risk profile of offshore wind in the United States today, showed expected return on equity of 17.36% for Kenetech (Kahn, 1995), a developer of wind projects at the time.[5]

5.5. Risk-free rate

The preceding debt and equity rates depend on the risk-free rate corresponding to the currency of the project, which for our purposes is the rate for 15-year interest-rate swaps against the 3-month USD LIBOR (hereafter simply "LIBOR"). In late 2010, LIBOR is around 3.75–4.0%. Such rates are unpredictable, however, the yield curve for USD LIBOR interest-rate swaps implies that market expectations are for a rise to 4.6% in January 2013 and to 5.2% in 2016–2021. By using the same required debt returns in our model as are prevalent today, we are implicitly assuming that the spread on debt for such projects will drop as the risk-free rate goes up. This follows the trend in the US land-based industry between 2006 and 2010 (Hennessy, 2010).

5.6. Cost of capital comparisons

A Weighted-Average Cost of Capital (WACC) based on our assumptions of cost of debt and equity is helpful in providing a comparison with other indicators. We present both the pre-tax forms of the WACC, which is useful for comparing to market rates, and the post-tax form, which is used in the model. The pre-tax WACC is given by

$$WACC_{pretax} = d*r_d + e*r_e$$

while the post-tax *WACC*, which accounts for the fact that debt payments are tax-deductible and thus provide a tax shield, is given by

$$WACC_{posttax} = d*r_d*(1-T) + e*r_e$$

where d is the market value of debt as a percentage of total capital, $e=(1-d)$ is the market value of equity as a percentage of total capital, r_d is the required return on debt, r_e is the required return on equity, and T is the corporate marginal tax rate. The values determined in the previous section (18% cost of equity, 8.0% cost of debt, and 64% debt fraction) yield a $WACC_{pretax}$ of 11.6% and a $WACC_{posttax}$ (at 35% tax rate) of 9.8%. These values (pretax/posttax) range from 9.6%/8.1% to 13.3%/11.2% as debt and equity rates vary according to the ranges above.

The Cape Wind PPA targets a debt rate of 7.5% and an after-tax unlevered internal rate of return 10.75% (which implies an assumed after-tax *WACC* of the same value) (Mass, 2010). Our debt assumption of 8.0% is slightly higher than the DPU assumption, and at 9.8%, our *WACC* is somewhat lower.

Offshore wind policy in the UK is informed by projections of system costs and target equity returns. Ernst & Young performed a study to inform the level of support for offshore wind, and targeted a post-tax nominal return of 12% (Ernst and Young,

[5] The reader is cautioned against placing too much weight on the Kahn figure in the context of this study, as the risk-free rate and risk premiums vary according to investor sentiment and economic conditions (Brealey et al., 2010)).

2009), much higher than our 9.4%. However, the policy which was actually implemented (New Energy Focus, 2009) corresponds to a targeted 10% return.

KPMG performed an analysis of the German policy structure for offshore wind power and determined that, with nominal post-tax returns of 7.1%, project revenues would not be sufficient to attract investors (KPMG, 2010).

6. Policy inputs

The United States has an inflation-indexed Production Tax Credit (PTC) worth \$22/MWh in \$2010. There is also an incentive called the Renewable Energy Production Incentive that is the equivalent of the PTC for non-tax-paying institutions. It has the same face value as the PTC, but involves a high level of regulatory risk since the program depends on congressional appropriations during each year of the incentive term.

Wind plants in the US also benefit from an accelerated depreciation schedule called 5-year Modified Accelerated Cost-Recovery System (hereafter referred to simply as "MACRS"). MACRS provides value to corporations by allowing them to defer paying tax. Periodic legislation also makes additional bonus depreciation available, though we do not consider it here. Interconnection costs are not eligible for accelerated depreciation, and these represent up to 20% of total CAPEX. For simplicity, we nonetheless model accelerated depreciation for 100% of CAPEX; the error is within our roughly 2% range.

Also for projects installed by 2012, the PTC can be foregone in favor of a 30% Investment Tax Credit (ITC), which for projects started in 2011 can be further exchanged for a cash grant called the Section 1603 grant. A multi-year extension of the ITC option has been proposed for offshore wind projects, but as of this writing its prospects are uncertain. Acceptance of the ITC or Section 1603 cash grant requires reduction of the depreciable basis by half of the amount of the tax credit or grant. The grant does not apply to transmission infrastructure, which in the case of offshore wind plants constitutes approximately 16% of CAPEX (Krohn et al., 2009). This is accounted for in the model.

State policies in the form of Renewable Portfolio Standards (RPSs) are discussed in Section 4.2 above; the value of renewable energy credits under RPS programs do not affect the Breakeven Price as we define it in this text.

The United States Department of Energy has had two loan guarantee programs, one designed for innovative technologies (Section 1703) for which offshore wind projects may qualify, and a temporary alternative to be used for commercial projects (Section 1705) that likely applies to offshore wind projects, but which expires at the end of 2011, and thus are not considered. Section 1703 loans are generally provided by the Federal Financing Bank at very low rates, and are accompanied by a reported-15% credit subsidy fee to cover the risk of default (PREF, 2009b). Section 1705 loans are supplied by pre-approved private lenders at somewhat higher rates. It is a complex matter to structure finance packages to achieve DOE loan guarantees as well as the ITC, PTC, or Section 1603 grant, especially together with the arrangement of tax equity, and the details and feasibility of such structures are beyond the scope of this paper. At the time of this writing, the risk-free rate is about 3.75%, yielding a Section 1703 rate of 4.00% and a Section 1705 rate of between 5.25% and 6.75%. To avoid underestimating the cost of such debt, we add an extra 75 bp to the Section 1703 premium. In both cases, the maximum amount of total debt allowed under the program is 80%, though we use the same 64% figure here as in the prior cases (PREF, 2009b). We use the same cost of debt as used for land-based wind, without the 100 bp adder, since the greater risk is covered by the guarantee. Finally, we exclude the 1705 program, as our study horizon (2015 and beyond) is past the end of the program.

7. Additional parameters

7.1. Inflation

Inflation is a measure of economy-wide price increases from year to year; it is generally represented by the Consumer Price Index (CPI) or Producer Price Index (PPI). We use our estimate of inflation as an input to the model for escalation for both electricity prices and OPEX. However, escalation of prices in a given sector or commodity can often be very different from inflation; there are specific measures of increases in wind turbine prices (Bloomberg Wind Turbine Price Index), overall power-plant costs (IHS Power Capital Costs Index), and electricity prices, as well as operating costs for the oil and gas industry (IHS Upstream Operating Costs Index). Because of the availability of long-term forecasts, we use only the CPI in our consideration of inflation.

Several groups publish projections of ten-year average inflation. The Federal Reserve Bank of Cleveland uses a proprietary model (resulting in 1.64%), while the Federal Reserve Bank of Philadelphia publishes the results of two surveys, the Livingston Survey (2.3%) and the Survey of Professional Forecasters (2.2%) (Cleveland Fed, 2010; Philadelphia Fed, 2010a; Philadelphia Fed, 2010b). Considering these projections, we use the inflation estimate of 2% over the life of the project.

7.2. Price escalator

Evidence suggests that most renewable energy Power Purchase Agreements (PPAs) in the United States include a price escalator (Mendelsohn, 2010c), in which the agreed purchase price is increased by some amount each year. These escalators range from close to zero to as high as 5%. We use a typical escalator of 2% in the model, which is conservative relative to the price escalators on US offshore wind PPAs, and which also matches our assumption for inflation; the power price under these conditions remains constant in real terms. One might ask, "Why would there be a price escalator in a PPA for wind?" By comparison, a typical contracted cost of energy for a thermal plant might set an initial electricity rate that covers the investment and fuel cost at commissioning, with adders for any increase in fuel costs, and, more recently, adders to compensate the generator for subsequent pollution taxes or carbon costs. A wind project will have no escalation in fuel costs, and does not have a future cost risk from pollution-related taxes or fees. Recent wind contracts have used a fixed escalator to bring the types of contracts more in parity with fossil-fuel plants, and to reduce the initial price premium for non-fuel generation, as the fossil fuel inflation rate has historically been greater than these fixed premiums, and does not include a price on emitting CO_2, which, despite the latest failure to introduce cap and trade to the United States, can reasonably be expected in the future. To model a contract reflecting an expectation of level fuel prices and no new fees for pollution or carbon, the price escalator in our model is set to the overall rate of inflation.

7.3. Project life

Wind turbines are typically engineered and certified to last 20 years, though many wind farms of the 1980s are still operating at the time of this writing, at least one manufacturer is targeting a 30-year life (Dvorak, 2010), and some PPAs in the United States have had terms longer than 20 years (Bluewater, 2008).

7.4. PPA and capital terms

In general, the debt term is shorter than the term of the PPA; in the United States, offshore wind PPAs have been signed for 15 years, 20 years, and 25 years. For the PPA, we take the middle case of 20 years, which is longer than typical terms in Europe.

The term of debt is modeled at 15 years (Mendelsohn, 2010c), and tax equity has a 10-year term, following the PTC.

8. Definition of Cost Scenarios

We model three Cost Scenarios (First Of A Kind, Global Average, and Best Recent Value) selected to represent the wide range of developer experience with offshore wind projects. Table 7 shows each of these scenarios along with the associated CAPEX and OPEX. We assume that all scenarios are sited in the same wind resource and use similar technology; thus capacity factor is held constant at 36%, reflecting winds in the Mid-Atlantic, as discussed above.

The First-Of-A-Kind (FOAK) scenario is intended to reflect the costs of an initial offshore wind project located in an undeveloped market such as the United States. The costs in this scenario are drawn from the high end of the ranges explored in Section 3, reflecting the elevated costs and risks associated with developing projects in a market without an established supply chain, specialized construction and installation equipment, trained personnel, or precedent for the arrangement of financing. The FOAK estimates are close to estimates made by the Massachusetts Attorney General in analyzing the Cape Wind project (Mass, 2010). Cape Wind is certainly a FOAK project in the US market, so this correspondence lends support to our model inputs.

The Global Average (GA) scenario is chosen to reflect the likely costs of building an offshore wind project in a more mature market such as Northern Europe. CAPEX is approximately equal to the capacity-weighted average of European projects completed between 2009 and 2010 and planned for 2011 through 2015, and OPEX is roughly in the middle of the projections discussed in Section 3. The GA scenario would be a reasonable expectation of the next stage of the US market, after experience with the current FOAK projects.

The Best Recent Value (BRV) scenario illustrates a best case for offshore wind project costs under current European market conditions using available technology. CAPEX in this scenario originates from the lowest values observed in projects installed in 2008 and 2009, and OPEX is representative of values from five projects installed as late as 2007. These BRV costs were achieved in the recent past, and it is plausible that offshore wind projects will be able to achieve them again as market volume and competition increase, even without technology improvements. The BRV CAPEX value is supported by recent bottom-up estimates (Hagerman et al., 2010), and the OPEX value is supported by projections from EWEA (2009) and others.

We chose not to model any scenarios that include the cost reductions likely to result from industry evolution and technology improvements, as the estimation of future costs is beyond the scope of this study. Even though we do not analyze industry evolution and technology improvements, we do expect further lowering of the Breakeven Price as the state of the art evolves to include larger turbines, increased reliability and production from offshore-specific designs, specialized vessels, purpose-built manufacturing facilities, superior O&M strategies, and increased familiarity and confidence on the part of the financial community. In fact, many of these improvements are already being funded, designed, and tested by industry, universities, and governments. A meta-analysis of studies addressing the issue of estimating future costs of offshore wind energy using learning rates is in Greenacre et al. (2010). However, note that our estimates of Breakeven Price are based on prior project costs, and assume no technology developments.

Table 7
Cost Scenarios for cash flow analysis.

	CAPEX, $/kW	**OPEX, $/MWh**
First of a Kind (FOAK)	$5750	$48
Global Average (GA)	$4250	$35
Best Recent Value (BRV)	$2970	$21
Improved technology	*Not estimated*	

9. Results

9.1. Results by policy incentive and financial structure

We calculate the Breakeven Price for each Cost Scenario with four Financial Structures: Corporate, Tax Equity, Project Finance, and Government Ownership (Table 8); we also calculate the LCOE. The Corporate case uses a single hurdle rate—based on a WACC derived from the capital structure and costs of the Project Finance case—to discount all free cash flows; the Tax Equity case uses an unleveraged “strategic tax equity flip” structure as described in Harper et al. (2007) with a 95% tax equity stake; the Project Finance case separates free cash flow into debt service payments and return to equity; and the Government Ownership case uses the same model as the Corporate case, but with the tax rate set to zero and a substantially lower discount rate that is representative of debt rates on government bonds. All values are nominal pre-tax unless otherwise stated (although the model ultimately analyzes after-tax cash flows). LCOE is calculated using the same discount rates as the Corporate case, but without any policy incentives, capacity payments, or accelerated depreciation.

Note that the discount rates are highest under the FOAK scenarios (reflecting the higher risks of financing an initial project), lower in the GA scenarios (where there is precedence for financing), and lowest in the BRV scenarios.

The Tax Equity model solves for a fixed return for Tax Equity, and return on standard equity is an output of the model. Due to constraints on this financial structure, returns to standard equity can be as high as 30%, consistent with the historical returns achieved by land-based wind developers that have used tax equity structures.

Table 8
Financial parameters for FOAK, GA, and BRV Scenarios. All values found here Tables 8 are nominal pre-tax. Tax rate is assumed to be 35% except for the government-owned case, which has no tax.

Financial Structure	Cost Scenario	Hurdle rate or cost of std. equity (%)	Cost of debt or tax equity (%)	Debt term	Debt or tax equity fraction
Corporate	FOAK	11.6	–	–	–
	GA	11.0	–	–	–
	BRV	7.8	–	–	–
Tax Equity	FOAK	–	13.5	–	95
	GA	–	13.5	–	95
	BRV	–	10.0	–	95
Project	FOAK	18	8.0	15y	64
	GA	18	7.0	15y	64
	BRV	15	6.0	15y	80
Government owned	FOAK	4.0	–	–	–
	GA	4.0	–	–	–
	BRV	4.0	–	–	–

Eligibility for the DOE Section 1703 Loan Guarantee Program (LGP) changes the debt structure such that 80% of the debt is sourced from a loan at 4.75% and 20% of the debt is at the debt rate listed in Table 8. Availability of the guarantee does not change the overall debt fraction or the debt term, and the guaranteed debt rate is the same across all cost scenarios and financial structures. Recall that projects with loan guarantees incur a substantial 15% charge to cover potential losses to the federal government.

We model the three Cost Scenarios (Table 7) with the four Financial Structures (Table 8) and the range of federal policy incentives available to a project under a given financial structure. Results are in Table 9. Federal policy incentives available to renewable energy projects in the United States as of this writing include the Production Tax Credit (PTC), the Investment Tax Credit (ITC), the Cash Grant in Lieu of ITC (Cash Grant), and the Loan Guarantee Program (LGP) (described in detail in Section 6). All of the cases (including those marked *None* in Table 9) include accelerated depreciation in the form of 5-year MACRS.

For the purposes of the model, the ITC and Cash Grant are identical, although the latter is easier to finance as it does not require tax equity or a corporate sponsor with large amounts of taxable income to offset; thus results for these two incentives are combined. Debt levels as determined in Table 8 are set to the proportion of capital required net of the value of the ITC or Cash Grant.

We assume that the Breakeven Price includes both power and environmental attributes, so we do not model the value of RECs separately. There are cases, such as in the Bluewater Delmarva PPA, in which power is sold separately from environmental attributes. In such cases, the RECs provide the project with an additional revenue stream and reduce the price as seen by the power buyers.

Projects financed with a Corporate structure cannot take advantage of the loan guarantee program because they do not include debt at the project level. This applies to our tax equity cases as well; we chose not to model a structure that employs both tax-equity and project level debt, as we consider this unlikely. We also chose not to model a government-owned project with the REPI incentive, as the payment of this incentive is not guaranteed and is subject to the availability of appropriated funds (DOE, 2007).

Table 9 shows Breakeven Price by Financial Structure, Cost Scenario, and policy incentive. LCOE results for the three cases (FOAK, GA, and BRV), respectively, are $303, $216, and $112/MWh.

The results of the model are intended to illustrate the wide range of Breakeven Prices that could result under various market

Table 9
Breakeven price (in $/MWh) by financial structure, maturity, and policy. The DOE Section 1703 loan guarantee program is modeled in columns marked "LGP".

Financial Structure	Cost Scenario	PTC		ITC or cash grant		No policy
		No LGP	*LGP*	*No LGP*	*LGP*	*No LGP*
Corporate	FOAK	$243	–	$205	–	$265
	GA	166	–	146	–	189
	BRV	78	–	75	–	98
Tax Equity	FOAK	$406	–	$334	–	–
	GA	290	–	245	–	–
	BRV	155	–	142	–	–
Project	FOAK	$241	$235	$220	$213	$268
	GA	164	164	158	156	192
	BRV	64	86	75	85	90
Government owned	FOAK	–	–	–	–	$160
	GA	–	–	–	–	117
	BRV	–	–	–	–	78

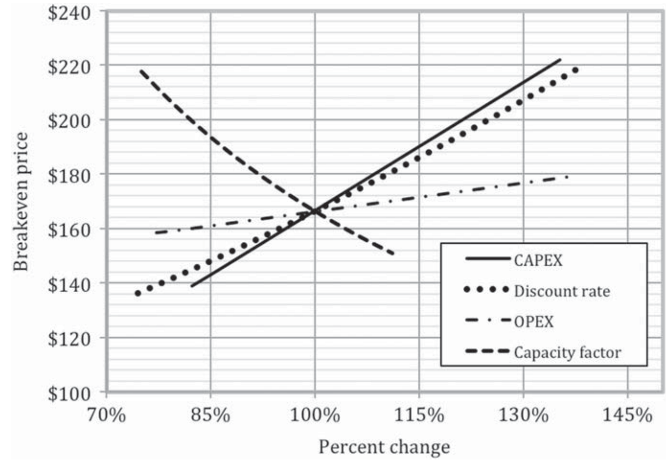

Fig. 3. Sensitivity analysis. Inputs at the intersection point correspond to the Corporate Global Average scenario in Table 7 above: $4,250 CAPEX, $35/MWh OPEX, 11% pre-tax nominal discount rate, and 36% net capacity factor. Policy incentives include PTC and accelerated depreciation but not RECs, ITC, or cash grant. These yield a Breakeven Price of $166/MWh at the intersection.

conditions, policy incentive options, and financing structures for near-term offshore wind projects in the U.S. waters. Though we made every attempt to define our scenarios and inputs to be reflective of anticipated conditions, we did not attempt to represent a specific project. As such, the Breakeven Prices resulting from our analysis should not be taken as the likely contract prices for specific proposed offshore wind projects. Instead, the results demonstrate the comparative impact of financing structures, policy incentives, and cost scenarios on Breakeven Price.

9.2. Sensitivity to physical parameters

We determine the sensitivity of the Breakeven Price to the four key variables (CAPEX, OPEX, capacity factor, and discount rate) using the Global Average (GA) Cost Scenario and a simple corporate-finance structure with PTC and MACRS. The plot in Fig. 3 shows the Breakeven Price as a single input parameter is varied while keeping the others fixed at the middle point of $4250/kW CAPEX, $35/MWh OPEX, 36% capacity factor, and 11% pre-tax nominal discount rate, with ranges based on those discussed in the text.

Fig. 3 shows that the Breakeven Price is most sensitive to CAPEX, the discount rate, and capacity factor, varying by ~$7/MWh for each 5% change in the input parameter. OPEX has less of an impact on Breakeven Price, which shifts ~$2/MWh for every 5% change, but greater uncertainty in the range means it still has a potentially important impact on the result.

10. Discussion

Several patterns are evident in the results: (1) Project and Corporate structures yield similar results, while the Tax Equity structure prices are higher than even the LCOE, due to the high required return on tax equity relative to standard equity and debt; (2) BRV prices are between 2.1 and 3.8 times lower than FOAK prices, demonstrating the cumulative impact of incremental changes in several parameters; (3) the ITC and cash grant scenarios show roughly double the impact of the PTC for FOAK and GA projects, but have little relative advantage or are disadvantageous for BRV projects, due to the reduction in the size of the cash grant with lower CAPEX, reduced debt leverage, and the PTC increasing as a share of revenue at a lower Breakeven Prices; (4) the DOE loan guarantee program has a modest effect on FOAK projects, but has no effect on GA projects and negatively impacts BRV projects, due to narrowing spreads between guaranteed and project loans as the industry matures coupled with high modeled transaction costs (this is just as well, since as of this writing the Section 1703 DOE loan guarantee program is only intended for FOAK projects); (5) the value of accelerated depreciation and capacity payments can be seen in the difference between the LCOE and the corporate cases in the *None* column—for FOAK and GA projects, these are worth substantially more than the PTC; (6) government ownership, with no explicit policy incentives, provides the lowest Breakeven Price for FOAK and GA Cost Scenarios, due to the low cost of government borrowing and absence of the requirement for high returns to equity investors. This last point suggests an opportunity for power authorities (e.g., New York Power Authority) or other authorized local government financing bodies, especially early in the development of the industry. Such public ownership would follow a similar trend in the land-based wind industry (e.g., at the White Creek, Windy Point, Nine Canyon, and Milford wind plants).

For perspective, we compare the prices in Table 9 to the market value of electric power. Since this comparison is complex, we use hearings by the Public Service Commissions of Delaware and Massachusetts for guidance. In these hearings, the States reviewed multiple ways to forecast the market value of electricity over 15 or more years. The Delaware study projected a regional price (in nominal terms) of about $100/MWh in 2013 and $130/MWh in 2027 (DEPSC et al., 2008), while the Massachusetts study projected $87/MWh in 2013 and $172 in 2027 (Milhous and Lloyd, 2010). Both commissions concluded that certain projects with costs higher than market value could be approved, because the higher electricity price was judged in light of the lack of other renewables in the region capable of meeting RPS goals, and the benefits of price stability and of large new clean power sources. Neither commission calculated external health costs in the price comparison. When these expected market prices from the commissions are compared with our estimates of the Breakeven Price of offshore wind under different conditions (Table 9), the Breakeven Price without any subsidy approaches market levels for BRV cases and for the government-owned GA case.

It is challenging to understand the cost of electricity from offshore wind projects. As we write, all offshore wind PPAs in the United States have prices above market values when no consideration is made of external costs. Due to the infancy of the industry and to vendor- and market-specific circumstances, deployed projects do not show a learning trend in costs; we address this circumstance by developing a model based on commercial-scale projects with complete, public data, then defining three Cost Scenarios: First Of A Kind (FOAK) (like the two US projects with PPAs), Global Average (GA) (the costs seen on average in Europe and China), and Best Recent Value (BRV), (the lowest cost parameters already found in one or more recent projects). The BRV is based only on actual recent project values—we do not project the additional future cost reductions due to new technologies now under development.

The differences in Breakeven Price among our Cost Scenarios is surprisingly large. Assuming corporate finance, accelerated depreciation, and the PTC (but not the ITC, RECs, a loan guarantee, nor other policy incentives), the Breakeven Price is $243 for FOAK, $166 for GA, and $78 for BRV. The US wholesale power prices inland can be lower than this, but for the Northeastern coastal states, the BRV of $78/MWh is below the market value of power as determined by two public regulatory commissions. Again, the BRV price assumes only that future construction can re-achieve the best values already achieved by recent projects. Re-achieving recent best values might happen if, for example, experience in planning, design, and management of equipment, plus development of port and installation vessel infrastructure yields cost reductions like those seen in the best prior projects.

The price reduction of moving from FOAK to GA to BRV is greater than the price reduction of existing subsidies. Assuming FOAK and corporate finance, the Breakeven Price is $265/MWh. The PTC lowers that to $243/MWh, and the ITC or cash grant only lowers it to $205. A government-owned FOAK project, with the cost of capital of a power authority, lowers the price to $160. So another surprise is that industry development would lower price more than current policies do, and that a government-owned system (like the hydro projects of the Bonneville Power Authority, Tennessee Valley Authority, and the NY Power Authority, or the publicly owned wind plants of the Northwest US) offers the most dramatic reduction in Breakeven Price. (See Dhanju (2010; Dhanju et al. accepted for publication) for a discussion of power authorities and offshore wind.)

We conclude that the high prices of FOAK projects recently receiving PPAs are a realistic reflection of risk, lack of experience, and lack of US offshore wind infrastructure. However, this analysis makes clear that observed the US FOAK power prices are not representative of the cost of offshore wind power, not in the long-term nor even the medium-term. Costs could be reduced toward Global Average (GA) and subsequently Best Recent Values (BRV) values without any technology development. We expect that technology development would lower those costs still further, but we do not estimate that price effect here.

The sensitivity analysis shows that, as expected, CAPEX is a critically important parameter to Breakeven Price. Less obvious is that the cost of capital is equal to CAPEX in importance, which means that risk policies and finance structure also have a strong influence on wind power prices. Capacity factor is equally important over the range of CF values in the US Atlantic region.

One policy mix that is consistent with these analytical findings would be to: (1) continue or expand the state and Federal policies that most reduce the cost of FOAK and GA projects as shown in Table 9, namely the ITC and cash grant programs; (2) facilitate industrialization of manufacturing and installation in order to shift toward GA and then BRV prices; and (3) support R&D to improve offshore turbine systems, foundations, and deployment, and thus lower cost below the BRV levels.

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