2011 Cost of Wind Energy Review

S. Tegen, E. Lantz, M. Hand, B. Maples, A. Smith, and P. Schwabe
National Renewable Energy Laboratory

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Technical Report
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March 2013

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List of Acronyms

AEP	Annual energy production
AEP_{net}	Net annual energy production
AOE	Annual operating expenses
AWEA	American Wind Energy Association
BNEF	Bloomberg New Energy Finance
BOEM	Bureau of Ocean Energy Management
BOS	Balance of station
CF_{net}	Net capacity factor
C_p	Coefficient of performance
CRF	Capital recovery factor
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
EIA	U.S. Energy Information Administration
ENS	Danish Ministry of Energy and Environment
EPRI	Electric Power Research Institute
FCR	Fixed charge rate
GWEC	Global Wind Energy Council
ICC	Installed capital cost
JEDI	Jobs and Economic Development Impact
kW	Kilowatt
LCOE	Levelized cost of energy
LLC	Land lease cost
LRC	Levelized replacement cost
MACRS	Modified Accelerated Cost Recovery System
MW	Megawatt
MWh	Megawatt-hour
NREL	National Renewable Energy Laboratory
O&M	Operation and maintenance
OCS	Outer Continental Shelf
PPA	Power purchase agreement
PTC	Production tax credit
PVdep	Present value of depreciation
TSR	Tip-speed ratio
WACC	Weighted average cost of capital

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Executive Summary

This report uses representative project types to estimate the levelized cost of wind energy (LCOE) in the United States for 2011. Published on an annual basis, it relies on both market and modeled data to maintain a current understanding of wind generation cost trends and drivers. It is intended to provide insight into current component-level costs and a basis for understanding variability in the LCOE across the industry. Data and tools developed from this analysis are used to inform wind technology and cost projections, goals, and improvement opportunities.

The primary elements of the 2011 report include:

- Estimated cost of energy for the reference land-based wind project installed in a midwestern or "heartland" site in 2011
- Estimated cost of energy for the reference fixed-bottom U.S. offshore wind project reflecting projects currently in late-stage development on the North Atlantic Coast
- Sensitivity analyses showing the range of effects basic LCOE variables could have on the cost of wind energy for land-based and offshore wind power plants.

For this analysis, the cost of wind energy is expressed as the LCOE. LCOE is a metric used by the U.S. Department of Energy (DOE) and others to evaluate the relative costs of electric-generating projects and the impact of technology design changes. In simple terms, LCOE is defined as:

$$\text{LCOE} = \frac{\text{present value of total costs (\$)}}{\text{lifetime energy production (megawatt-hours)}}$$

The LCOE equation applied here is a standard methodology (Short et al. 1995, EPRI 2007) that includes four basic inputs: installed capital cost, annual operating expenses (AOE), annual energy production, and the fixed charge rate (a coefficient that captures the cost of financing a wind project and plant operational life). Additional detail on LCOE can be found in the *2010 Cost of Wind Energy Review* (Tegen et al. 2012).

LCOE values reported here are expected to be greater than negotiated contract prices for wind power, as reflected by recent power purchase agreements. This is because recent power purchase agreements incorporate the value of the production tax credit (PTC) and any other Renewable Energy Credit or other applicable revenue streams.

Key Inputs and Results

Throughout the document, the representative land-based and offshore project types are referred to as "reference projects." Tables ES1 and ES2 summarize the four basic LCOE inputs for the reference land-based and fixed-bottom offshore wind projects, with some additional detail around project capital costs and the respective turbine capacity factor associated with the net annual energy production estimate. These are the assumptions used to calculate LCOE for the 2011 reference projects. In each table, the left-hand column shows the data source. "Model" refers to the techno-economic models used, such as the National Renewable Energy Laboratory's (NREL's) wind turbine design cost and scaling model (Fingersh et al. 2006, Maples et al. 2010). "Market" indicates that NREL used current market data, with individual data sources listed in sections of this paper related to the specific cost components. "Literature" represents costs that originated from a 2011 publication.

Table ES1. Summary Description of the Land-Based Wind Reference Project, Using 1.5-MW Turbines

Data Source		1.5-MW Land-Based $/kW	1.5-MW Land-Based $/MWh
Model	Turbine capital cost	1,286	37
Model	Balance-of-station	446	13
Model	Soft costs	172	5
Market	Market price adjustment*	195	6
Market	**INSTALLED CAPITAL COST**	**2,098**	**61**
Market	Annual operating expenses ($/kilowatt/yr)	35	11
Market	Fixed charge rate (%)	9.5	
Model	Net annual energy production (megawatt-hour/MW/yr)	3,263	
Model	Capacity factor (%)	37	
	TOTAL LCOE ($/MWh)	**72**	

*The market price adjustment is the difference between the modeled cost and the actual price paid for the typical project in the 2011 market.

Table ES2. Summary Description of the Fixed-Bottom Offshore Wind Reference Project, Using 3.6-MW Turbines

Data Source		3.6-MW Offshore $/kW	3.6-MW Offshore $/MWh
Literature	Turbine capital cost	1,789	62
Market	Balance-of-station costs	2,918	101
Literature	Soft costs	893	31
Market	**INSTALLED CAPITAL COST**	**5,600**	**194**
Market	Annual operating expenses ($/kilowatt/yr)	136	40
Market	Fixed charge rate (%)	11.8	
Model	Net annual energy production (megawatt-hour/MW/yr)	3,406	
Model	Capacity factor (%)	39	
	TOTAL LCOE ($/MWh)	**225**	

Land-based wind project cost estimates were derived primarily from installed project data reported by Wiser and Bolinger (2012) and supplemented with outputs from NREL's wind turbine design cost and scaling model. Because of the absence of installed or operating offshore wind projects in the United States, the offshore reference project data were estimated from proposed U.S. projects and the existing international offshore wind industry. The assumed wind resource regime for the offshore reference plant is comparable to that of the U.S. North Atlantic Coast. The land-based reference project was assumed to have a moderate wind resource regime and to be located within the "heartland" region of the United States.

More detailed breakdowns of installed capital costs (ICC) are shown in Figures ES1 and ES2. The three major component cost categories and many subcategories are represented in these figures, including: turbine (e.g., wind turbine components), balance of station (e.g., permitting, transport, support structure, and installation), and soft costs (e.g., insurance and construction finance). From these data, it is clear that the breakdown of wind turbine component and installation costs varies greatly between land-based and offshore turbines. For example, the majority of the land-based project cost (68%) is in the turbine itself; whereas the turbine makes up only 32% of the offshore reference project.

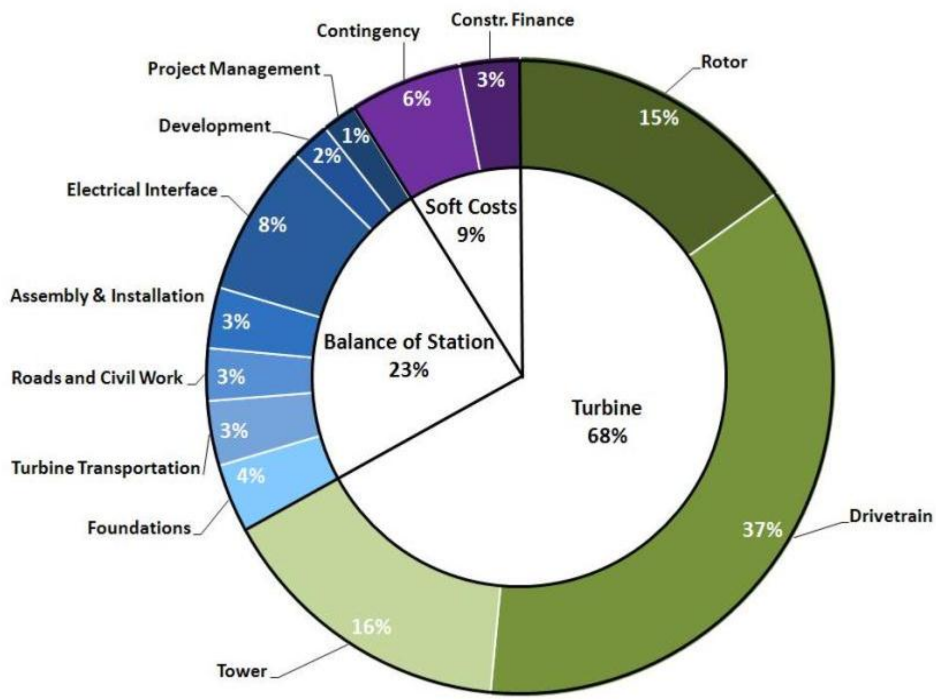

Figure ES1. Installed capital costs for the land-based wind reference project

Source: NREL

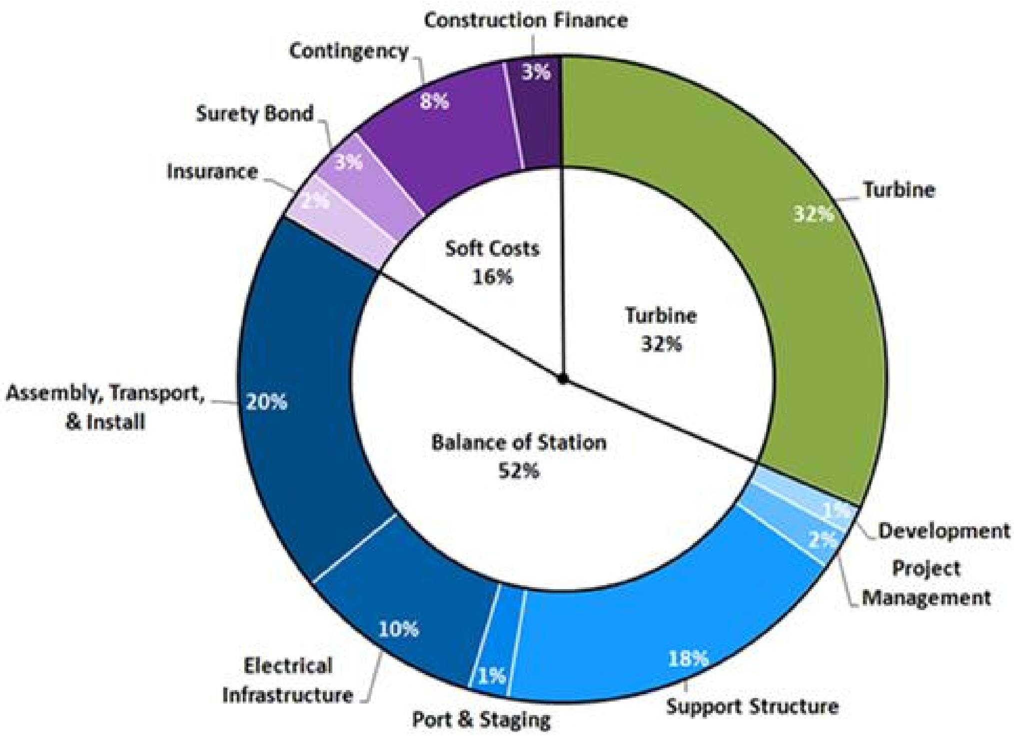

Figure ES2. Installed capital costs for the offshore wind reference project

Source: NREL

Figures ES3 and ES4 detail the LCOE associated with the land-based and offshore reference plants along with a range of sensitivity variables affecting cost and performance. Reference project values of $72/megawatt-hour (MWh) for land-based wind and $225/MWh for offshore wind rely on inputs summarized in Tables ES1 and ES2 (and identified by the white line in these figures). Figures ES3 and ES4 also show the observed industry ranges for LCOE inputs. To provide more detail on the fixed charge rate (FCR), the authors divided it into two principal components: discount rate and operational life. Annual energy production (AEP) was converted to capacity factor to assist in conveying the full range of performance reflected by 2011 projects. As shown, the land-based capacity factors from 2011 projects range from 18% to 53% (Wiser and Bolinger 2012), with an assumed 37% for the 2011 reference project. Clearly, the ranges for land-based and offshore wind LCOE inputs vary significantly (note the different axes in these figures). For example, offshore wind capacity factor ranges from 30% to 55%, with an assumption of 39% for the reference project. More detailed descriptions of the ranges and assumptions shown here are included in the body of the report.

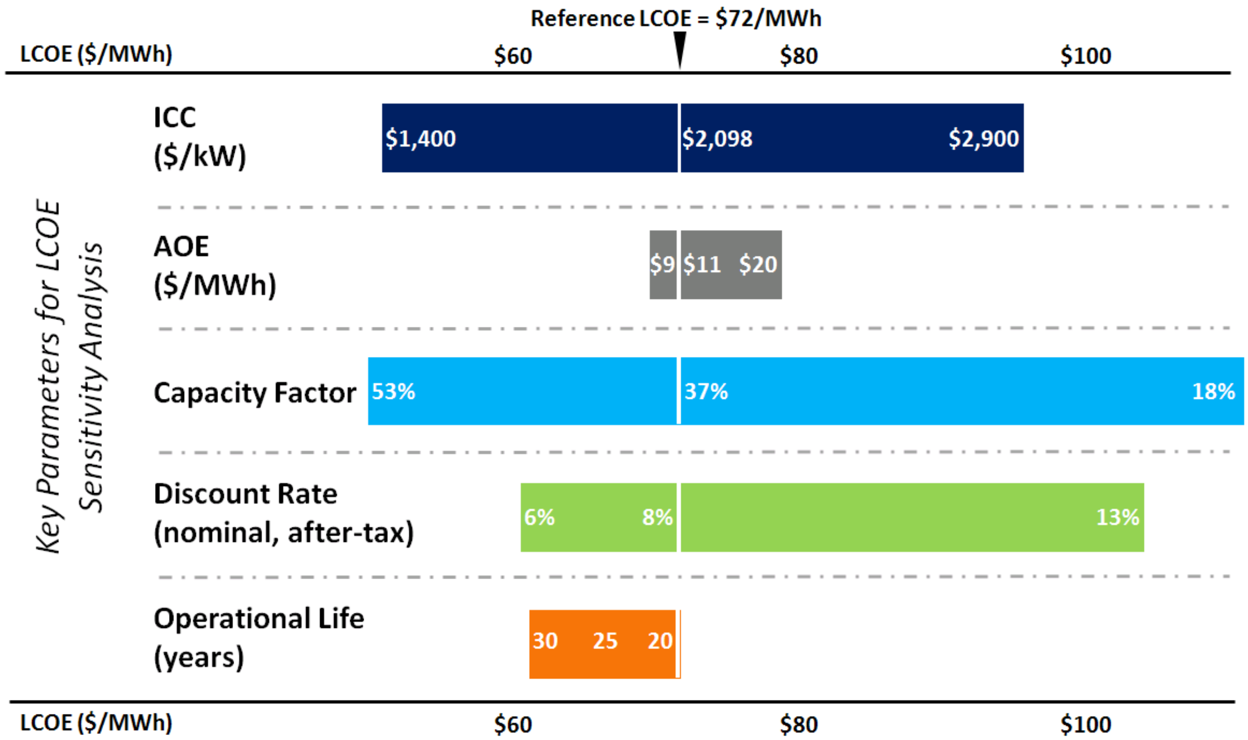

Figure ES3. Land-based wind assumptions and ranges for key LCOE input parameters

Source: NREL

Note: The reference LCOE represents the estimated LCOE for the NREL reference plant. Changes in LCOE for a single variable can be understood by moving to the left or right along a specific variable. Values on the X-axis indicate how the LCOE will change as a given variable is altered, and assuming that all others are constant. For example, as capacity factor decreases toward 18%, the LCOE shown on the X-axis will increase accordingly to more than $100/MWh. As the operational life for the reference project moves toward 30 years, the LCOE will decrease to nearly $60/MWh.

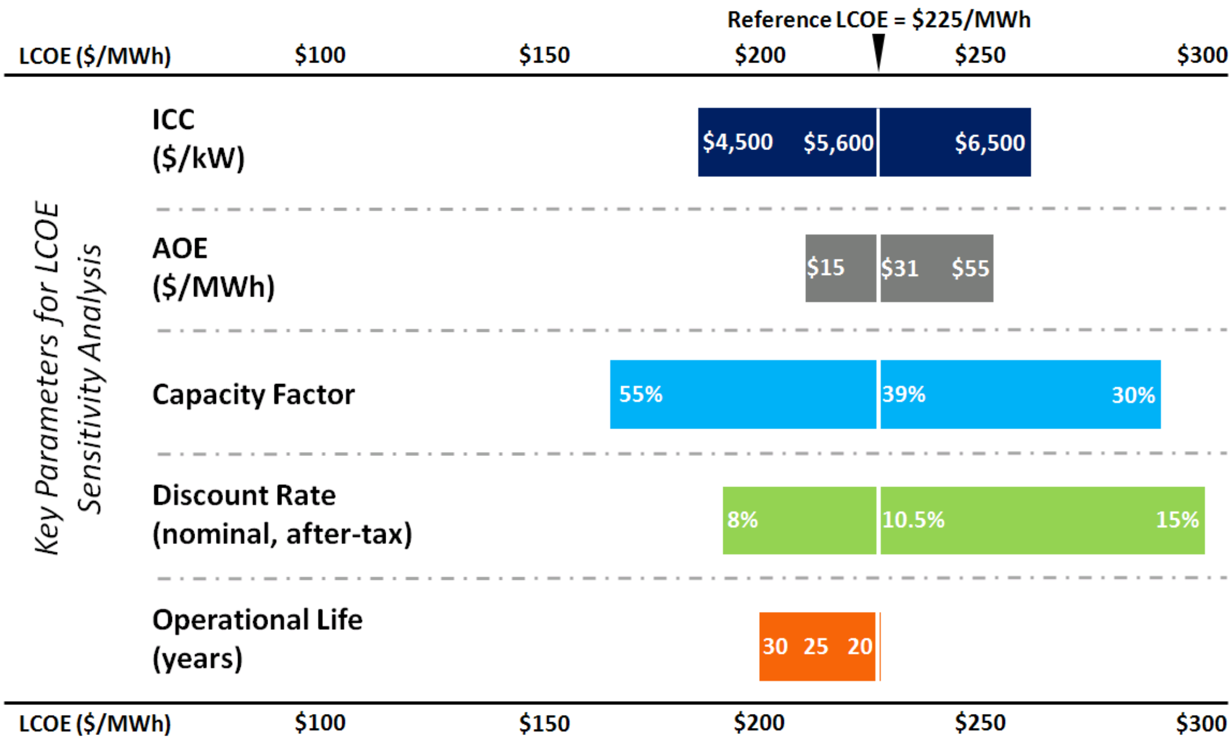

Figure ES4. Offshore wind assumptions and ranges for key LCOE input parameters

Source: NREL

Along with the reference LCOE estimates, NREL researchers created additional land-based wind project scenarios to demonstrate the impact of two specific project permutations: lower installed capital cost and higher average annual wind speed. Both of these scenarios resulted in a lower LCOE relative to the reference project, with the former resulting in an LCOE of $62/MWh and the latter resulting in an LCOE of $65/MWh. The altered variables and their resulting LCOE are summarized in Table ES3.

Table ES3. Land-Based LCOE Cost Reduction Scenarios

	Reference	Reduced ICC	Higher Annual Wind Speed
Installed capital cost ($/kW)	$2,098	$1,750	$2,098
Annual operating expenses ($/kilowatt)	$35	$35	$35
Net annual energy production (MWh/MW/yr)	3,263	3,263	3,578
LCOE ($/MWh)	**$72**	**$62**	**$65**

From these results, researchers came to the following key conclusions:

- Final LCOE estimates differ only slightly from those in the 2010 report. For land-based technology, this may be surprising because of continued observed reductions in turbine pricing. However, the discrepancy is a result of the lag time between turbine price changes, power purchase agreement contract negotiations, and project commissioning. Offshore turbine costs have not shown the same cost reductions observed in the land-based segment of the industry, therefore, there is a consistent result between 2010 and 2011 that aligns well with current offshore wind market dynamics.
- Although the reference project LCOE for land-based installations was observed to be \$72/MWh, the full range of land-based estimates covers \$50–\$148/MWh.
- The reference project offshore estimate is \$225/MWh, with a full range of \$168–\$292/MWh. This dramatic range is mostly caused by the large variation in installed capital costs [\$4,500–\$6,500/kilowatt (kW)] reported by project developers.
- The sensitivity analysis shows that LCOE can vary widely based on changes in any one of several key factors. However, the variable with the most dramatic effect on LCOE is capacity factor. This is the case for both land-based and offshore projects.

Although LCOE calculations in this report do not include policy factors, it should be noted that the outlook for the 2012 and 2013 U.S. wind market is not as optimistic as in 2010 and 2011. In part, this is the result of significant policy uncertainty regarding the PTC throughout 2012. The anticipated expiration of the PTC forced substantial acceleration of wind development; so much that, even with the January 1, 2013, extension of the PTC, demand for new wind projects is expected to be weak. The American Wind Energy Association (2012) reported that three past expirations of the PTC resulted in a drop of 73%–93% for annual land-based wind installations in the year after expiration. Analyst forecasts based on a late 2012 one-year extension of the PTC (similar to what was signed into law in early 2013) suggest an approximate 65% reduction in installations (BNEF 2012a). Wiser and Bolinger (2012) also observed that low natural gas prices and only modest electricity demand growth are expected to reduce demand for wind power installations in 2013 and coming years, “despite recent improvements in the cost and performance of wind power technology.”

Related and Future Work

This annual report is intended to provide greater insight into component-level costs and their effects on LCOE. This work will also contribute to the existing LCOE literature through basic data gathering and by providing a basis for more in-depth understanding of the future cost of wind developments. Looking ahead, NREL will continue to work with industry experts and national laboratory partners to obtain detailed, empirical, project-specific data and continue to develop advanced systems-oriented modeling capabilities. NREL's ongoing wind analysis efforts include the development of:

- Research that focuses on understanding current and historical operation and maintenance costs, including major component replacement costs
- A model to better represent land-based and offshore nonturbine project costs, such as foundations, electrical cabling, and installation, across a range of turbine and project sizes
- A wind energy systems engineering model to conduct enhanced analysis of the effect of new innovations on turbine cost and performance.

In addition, NREL plans to:

- Estimate the effect on LCOE from anticipated improvements to operations and maintenance in both land-based and offshore wind projects
- Determine the magnitude and impact of wake losses
- Quantify the effect of potential innovations on system LCOE for both land-based and offshore wind technology
- Collect data and examine key issues involved in wind power deployment, such as transmission, radar, wildlife issues, and public acceptance, to better understand their impacts on the cost of wind energy and potentially developable land
- Assess small and midsize wind technology costs.

1 Background

Levelized cost of energy (LCOE) is a metric used to evaluate the cost of electricity generation and the total plant-level impact from technology design changes. LCOE can be used to compare costs of all types of electricity, as long as the same formula and calculations are used for each type. Different methodologies have been developed to calculate LCOE; the one used for this analysis is fully described in *A Manual for the Economic Evaluation of Energy Efficiency and Renewable Energy Technologies* (Short et al. 1995).[1] Use of LCOE is especially important for technologies, where there is a constant tradeoff between maintaining or reducing capital investment and increasing energy capture, like wind and solar power.

There are four basic inputs into the LCOE equation. The first three—installed capital cost (ICC), annual operating expenses (AOE), and annual energy production (AEP)—enable this equation to capture system-level impacts from design changes (e.g., taller wind turbine towers). The total costs of financing are represented by the fourth basic input—a fixed charge rate (FCR)—that determines the amount of revenue required to pay the carrying charges[2] on an investment while capturing expected plant life.[3] For this analysis, the life of a wind project is assumed to be 20 years. LCOE results are reported in constant 2011 dollars.

This report provides an update to the *2010 Cost of Wind Energy Review* (Tegen et al. 2012). However, it offers an abbreviated look at the 2011 wind LCOE, turbine costs, financing, and market that will be followed by a more comprehensive review in the next edition. It addresses three specific areas:

- Estimated cost of energy for the reference land-based wind project located in a midwestern or "heartland" site in 2011
- Estimated cost of energy for the reference fixed-bottom U.S. offshore wind project reflecting projects currently in late-stage development on the North Atlantic Coast
- Sensitivity analyses showing the range of effects basic LCOE variables could have on the cost of wind energy for land-based and offshore wind power plants.

Despite addressing a number of assumptions and cost variables, this report does not capture the full spectrum of drivers that affect wind energy costs. For example, it does not consider policy incentives (such as the production tax credit, or PTC), factors from underlying economic conditions (such as an economic recession), the cost of building long-haul interstate transmission, or potential integration costs. These are important variables that can significantly impact wind power costs by adding expenditures, delaying projects, or halting projects altogether. Nevertheless, their exclusion is consistent with past work conducted by the National Renewable Energy Laboratory (NREL) (Tegen et al. 2012, Lantz et al. 2012) and others in this

[1] For an overview of cost-of-energy calculators and models, see Gifford et al. (2011).
[2] Carrying charges include the return on debt, return on equity, taxes, depreciation, and insurance.
[3] The fixed charge rate does not allow for detailed analysis of specific financing structures. However, these structures can be represented through the use of a weighted average cost of capital as the discount rate input.

space (BNEF 2012b, Lazard 2008), as LCOE is not traditionally defined as a measure of all societal costs and benefits associated with power generation resources.

The following equation is used to calculate LCOE:

$$\text{LCOE} = \frac{(\text{ICC} \times \text{FCR}) + \text{AOE}}{(\text{AEP}_{\text{net}}/1{,}000)}$$

Where:

LCOE	=	levelized cost of energy [$/megawatt-hour (MWh)]
FCR	=	fixed charge rate (%)
	=	$\frac{d(1+d)^n}{(1+d)^n - 1} \times \frac{1-(T \times PVdep)}{(1-T)}$
ICC	=	installed capital cost ($/kilowatt [kW])
AEP_{net}	=	net annual energy production (MWh/MW/yr)
		$\text{MW x 8760} \times CF_{net}$
AOE	=	after-tax[4] annual operating expenses ($/kW/yr)
	=	$LLC + O\ \&\ M + LRC$
d	=	discount rate (%)
n	=	operational life (years)
T	=	effective tax rate (%)
$PVdep$	=	present value of depreciation (%)
CF_{net}	=	net capacity factor (%)
LLC	=	land lease cost ($/kW/yr)
$O\&M$	=	after-tax levelized operation and maintenance (O&M) cost ($/kW/yr)
LRC	=	levelized replacement cost ($/kW/yr)

[4] After-tax expenditures reflect the cost to developers less the value of any relevant tax deductions that may be applied.

2 Approach

The *2011 Cost of Wind Energy Review* applies the same approach as the 2010 report (Tegen et al. 2012). A number of data sources and models were used in NREL's estimation of the cost of wind energy. For land-based wind technology calculations, the U.S. had over 46,000 megawatts (MW) of capacity installed and operating in 2011. These wind projects provided a large sample of empirical data on plant costs and performance. By contrast, offshore wind technology was not deployed in the United States at the time of this study, and the market data supporting offshore cost of wind energy estimates are limited to international projects and proposed U.S. projects.

In addition to historical market data, models were employed to estimate disaggregated plant-level cost components. Therefore, detailed data are provided on the individual components that make up capital cost, operating cost, and estimated energy production for the reference projects defined here. Given the market and model data available, the general approach for estimating the levelized cost of wind energy includes:

1. Evaluating market conditions and data for projects that have been installed in the United States (or in Europe and Asia when considering offshore wind technology) in a given year, to understand installed project cost, AEP, operating costs, and representative turbine technology. The primary source for these data is the U.S. Department of Energy's (DOE) *Annual Wind Technologies Market Report* (Wiser and Bolinger 2012). Accordingly, LCOE estimates reflect market conditions to the extent possible. For example, the installed capital cost for the 2011 land-based reference project equals the average U.S. installed capital cost reported by Wiser and Bolinger for 2011.
2. Supplementing market data for realized projects with modeled data based on a representative or reference project that reflects technology and project parameters for a given year. Principally, NREL's wind turbine design cost and scaling model (Fingersh et al. 2006, Maples et al. 2010) is used to estimate the capital cost and AEP of a project based on turbine rated capacity, rotor diameter, hub height, and a representative wind resource. This model uses scaling relationships at the component level (e.g., blade, hub, generator, and tower) developed with curve-fit industry data, published scaling models, and turbine models developed through the WindPACT studies (e.g., Malcolm and Hansen 2006) that reflect component-specific and often nonlinear relationships between size and cost (see Appendix C in Tegen et al. 2012). The use of this model provides additional component-level details for turbines (with user-defined parameters) and plants.
3. Combining the market data and modeled data described above to estimate the primary elements necessary to calculate LCOE (i.e., ICC, AOE, AEP, and FCR) and provide details about wind technology costs and performance that are aligned with market data but reported at higher resolution.

This approach is useful in that the reference project is described with a level of detail that is based on technology specifications, while market conditions are preserved. However, reliance on modeled data for disaggregated component-level and energy production estimates also introduces a degree of uncertainty in some LCOE input variables. Model uncertainty is introduced principally in two areas:

1. Modeled installed capital cost tends to underestimate market data that are influenced by factors not captured by the model (e.g., the value of the U.S. dollar, industry profit margins, foreign labor costs, and changes in warranty terms or servicing agreements that are wrapped into turbine supply agreements).
2. The modeled AEP_{net} estimate relies on an input related to total losses across the reference project. However, production losses are, in reality, site- and technology-dependent, and measurements for individual projects are not available.

To address these two sources of uncertainty, model estimates for installed capital cost and capacity factor are forced to reflect market data by applying a “market adjustment” and generic “losses” terms in the model. These terms apply global adjustment factors (coefficients) to cost and production estimates that account for the myriad of factors that are not explicitly modeled, but that have a significant cumulative effect. Continued efforts to improve the fidelity of NREL’s bottom-up models should result in greater confidence associated with individual component estimates and plant-level production; however, it is unlikely that differences between market and modeled data will ever be fully resolved.

The following sections of this report describe each component—ICC, AOE, AEP, and FCR—of the LCOE equation, market context, and range of data for typical U.S. wind projects in the year 2011. This *2011 Cost of Wind Energy Review* first describes the 2011 LCOE components for a land-based reference project using 1.5-megawatt (MW) turbines. Then, it describes the 2011 LCOE components for an offshore wind reference project using 3.6-MW offshore turbines.

3 Land-Based Wind

The land-based wind reference project is derived from representative characteristics of 2011 wind projects consisting of 133, 1.5-MW turbines (200 MW total installed capacity). Reference project wind turbine and component costs are based on a three-stage planetary/helical gearbox feeding a high-speed asynchronous generator and a standard spread-foot foundation design. Annual operating expenses for this project reflect estimates from 69 projects built since 2000 (Wiser and Bolinger 2012). The reference project wind regime is generally equivalent to a moderate wind resource site in the midwest or "heartland" region of the United States—the region where the greatest number of wind projects were installed in 2011 (Wiser and Bolinger 2012).

In 2011, the capacity-weighted average "all-in"[5] installed costs were reported to be $2,098/kW, with total AOE reported at $35/kW/yr (Wiser and Bolinger 2012). Accordingly, these values were ascribed to the land-based reference project. Given these inputs as well as the additional variables considered to reflect the reference project and summarized in Table 1 below, the resulting LCOE is $72/MWh.

Table 1. Summary of Inputs and Reference Project LCOE for Land-Based Installations

Data Source		1.5-MW $/kW	1.5-MW $/MWh
Model	Turbine capital cost	1,286	37
Model	Balance of station	446	13
Model	Soft costs[6]	172	5
Market	Market price adjustment[7]	195	6
Market	**INSTALLED CAPITAL COST**	**2,098**	**61**
Market	Annual operating expenses ($/kW/yr)	35	11
Market	Fixed charge rate (%)	9.5	
Model	Net annual energy production (MWh/MW/yr)	3,263	
Model	Capacity factor (%)	37	
	TOTAL LCOE ($/MWh)	**72**	

[5] Overnight capital costs represent the cost of building a plant overnight and do not include financing or escalation costs. The "all-in" capital costs do include financing and escalation costs that can vary with risk perception, construction schedules, inflation expectations, and other factors.
[6] Soft costs are nonconstruction costs incurred before project commissioning, primarily related to the cost of financing.
[7] The market price adjustment is the difference between the modeled cost and the price paid for the typical project in the 2011 market.

3.1 Installed Capital Cost for Land-Based Wind

The weighted average installed capital cost (ICC) and operating expenditure data are published annually by DOE in the *Wind Technologies Market Report* (Wiser and Bolinger 2012). The analysis conducted here applies the NREL wind turbine design cost and scaling model to estimate component-level costs that were calibrated to the market-based total cost estimates from Wiser and Bolinger (2012). This calibration was necessary because recent trends have been influenced by variables that are not captured in the current modeling capabilities (see details in Section 2).[8]

Figure 1 illustrates the breakdown of ICC for the NREL land-based reference project. The ICC components highlighted in shades of green capture the turbine capital cost; components highlighted in blue capture the balance-of-station (BOS) share of capital costs; and components highlighted in purple capture the soft capital costs. For information on the assumptions and inclusions of the individual components, see Tegen et al. (2012), Maples et al. (2010), and Fingersh et al. (2006).

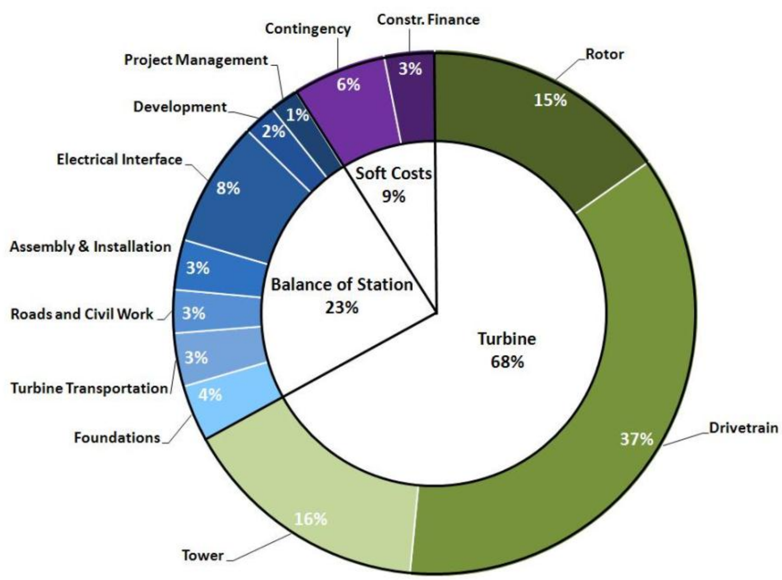

Figure 1. Installed capital costs for the land-based wind reference project

Source: NREL

Table 2 summarizes the costs for individual components (including their contribution to LCOE) for the reference project, again based on a project that uses a 1.5-MW turbine. Data sources for this table are described in Appendix B.

[8]NREL is working to develop a bottom-up model that associates physical parameters with cost estimates. Although this approach is still likely to underpredict the total, it can provide greater fidelity in component cost and relative component cost change with the size of the turbine.

Table 2. Land-Based LCOE and ICC Breakdown

	1.5-MW $/kW	1.5-MW $/MWh
Rotor	292	9
Blades	178	5
Hub	53	2
Pitch mechanism and bearings	57	2
Spinner, nose cone	4	*
Drivetrain, nacelle	667	19
Low-speed shaft	36	1
Bearings	20	1
Gearbox	144	4
Mechanical brake, high-speed coupling	2	*
Generator	91	3
Variable-speed electronics	108	3
Yaw drive and bearing	32	1
Mainframe	126	4
Electrical connections	76	2
Hydraulic, cooling system	17	*
Nacelle cover	16	*
Control, safety system, and condition monitoring	30	1
Tower	296	9
TURBINE CAPITAL COST	**1,286**	**37**
Turbine transportation	63	2
Permitting	1	*
Engineering	7	*
Meteorological mast and power performance engineering	5	*
Access road and site improvement	42	1
Site compound and security	5	*
Control and operation and maintenance building	4	*
Turbine foundation	68	2
Turbine erection	59	2
Medium-voltage electrical material	76	2
Medium-voltage electrical installation	25	1
Collector substation	26	1
Transmission line and interconnection	21	1
Project management	17	*
Development	25	1
BALANCE OF STATION	**446**	**13**

Market price adjustment	195	6
Contingency fund	112	3
SOFT COSTS	**307**	**9**
OVERNIGHT CAPITAL COST	**2,038**	**59**
CONSTRUCTION FINANCING COST	**60**	**2**

*Less than 1.

Capital costs for projects installed in 2011 ranged from $1,400/kW to $2,900/kW for utility-scale wind projects (Wiser and Bolinger 2012), with many factors driving these differences (such as terrain, site access, and regional labor costs). Because of capital cost variability, estimates for each capital cost component were established using the NREL wind turbine design cost and scaling model and a market price adjustment was added to bring the all-in capital cost in line with the industry average. The market price adjustment accounts for fluctuations in component costs, profit margins, foreign exchange rates, supply chain constraints, and other market conditions. This analysis does not attempt to predict which capital cost components are influenced by the market price adjustment, as these impacts can vary from project to project.

Balance of station (BOS) costs were estimated using new scaling relationships and costs from detailed data obtained through a major Engineer, Procure, and Construct firm active in the wind industry. These new relationships provided a basis for understanding the underlying impacts of innovative turbine component designs on the BOS costs as well as the impacts of innovative BOS concepts. This additional cost information enabled a more detailed breakdown of BOS categories.[9] Construction financing was estimated at 3% of hard costs, which is consistent with industry reporting.

3.2 Annual Operating Expenses for Land-Based Wind

Annual operating expenses (AOE) typically include land-lease costs (LLC), operation and maintenance (O&M) wages and materials, and levelized replacement costs (LRC). O&M costs are generally expressed in two categories: 1) *Fixed* O&M, which includes known operations costs (e.g., scheduled maintenance, rent, leasing, taxes, utilities, or insurance payments) and typically does not change depending on how much electricity is generated, and 2) *Variable* O&M, which includes unplanned maintenance and other costs that may vary throughout the project life depending on how much electricity is generated. For simplicity, AOE can be converted to a single term and expressed as either dollars per kilowatt per year ($/kW/yr) or dollars per megawatt-hour ($/MWh). This analysis uses the $/kW/yr convention.

Annual O&M estimates are calculated from recent estimates of operating costs for projects built since 2000. Wiser and Bolinger (2012) reported an average O&M value of $28/kW/yr that generally incorporates the costs of wages and materials associated with operating and maintaining a facility, but likely excludes other elements such as insurance, taxes, or

[9] Additional detail on the new BOS data and scaling relationships will be published in a separate report later this year.

depreciation.[10] This analysis interprets the Wiser and Bolinger (2012) estimates as a pretax value while the LCOE equation treats O&M expenses as tax deductible. Therefore, these estimates are converted to an after-tax value by multiplying the O&M estimate by (1-T), where T is the effective combined (state and federal) tax rate, assumed to be 38.9%.

The AOE values reported here include the average estimated property tax payments from NREL's Jobs and Economic Development Impacts (JEDI) model and the LRC for major turbine components from Cohen et al. (2008). Property tax costs and LRC bring the total after-tax AOE to $35/kW/yr. It should be noted that, given the scarcity and varying quality of the data, AOE can vary substantially among projects (Wiser and Bolinger 2012), and the data presented here may not fully represent the challenges that annual operating expenses present to the wind power industry.

3.3 Annual Energy Production and Capacity Factor for Land-Based Wind

Annual energy production (AEP) for this analysis is computed using the NREL wind turbine design cost and scaling model. The model computes annual energy capture and other related factors, such as capacity factor, for a wind project that is specified by generic input parameters. Parameters used for the calculation of AEP are presented in Table 3. The input parameters for calculating AEP can be grouped into three general categories: turbine parameters, wind resource characteristics, and losses.

[10] Alternatively, if expressed in $/kWh terms, O&M estimates in 2011 ranged from $5 to $20/MWh (based on plants with a commercial operation date of 2010), with the 2011 O&M baseline estimate of $9/MWh (Wiser and Bolinger 2012).

Table 3. Reference Land-Based AEP Input Assumptions

Turbine Parameters	
Turbine rated power (MW)	1.5
Turbine rotor diameter [meters (m)]	82.5
Turbine hub height (m)	80
Maximum rotor tip speed [meters per second (m/s)]	80
Tip-speed ratio at maximum coefficient of performance (C_p)	8
Drivetrain design	Geared
Rotor peak (C_p)	0.47
Wind Resource Characteristics	
Annual average wind speed at 50-m height (m/s)	7.25
Weibull K	2
Shear exponent	0.143
Elevation [above sea level (m)]	450
Losses	
Losses (i.e., array, energy conversion, and line)	15%
Availability	98%

3.3.1 Turbine Parameters

Turbine parameters are characteristics that are specific to the turbine and independent of wind characteristics. These parameters consist not only of turbine size (such as rated power, rotor diameter, and hub height), but also of turbine operating characteristics [such as maximum rotor capacity (Cp), maximum tip speed, maximum tip-speed ratio (TSR), and drivetrain design]. Because the geared drivetrain topology dominates the U.S. market, a geared drivetrain was selected for the baseline turbines. For the specific approach used regarding additional turbine parameters (e.g., power curves), see the *2010 Cost of Wind Energy Review*.

3.3.2 Wind Resource

The annual average wind speed chosen for the reference project analysis is 7.25 meters per second (m/s) at a 50-m height above ground level (7.75 m/s at hub height). This wind speed is representative of a Class 4 wind resource (7–7.5 m/s) and is intended to be generally indicative of the wind regime for projects installed in moderate quality sites in the “heartland” (Minnesota to Oklahoma). An elevation above sea level of 450 m is used based on the representative “heartland” site. The elevation above sea level coupled with a hub height of 80 m results in an average air density of 1.163 kg/m^3.

3.3.3 Losses

Although some losses can be affected by turbine design or wind characteristics, losses are treated as independent of any other input in this simplified analysis. Types of losses accounted for in this analysis include array losses, collection and transmission losses (from the substation to the point of interconnection), soiling losses, and availability. Net annual energy production (AEP_{net}) is calculated by applying all losses to the gross AEP. Table 4 shows the AEP, capacity factors, and losses and availability for the land-based reference turbine operating in 2011.

Table 4. Land-Based Wind Turbine AEP and Capacity Factor Summary

	1.5-MW Land-Based
Gross AEP (MWh/MW/yr)	3,917
Gross capacity factor (%)	45
Losses and availability (%)	17
Net AEP (MWh/MW/yr)	3,263
Net capacity factor (%)	37

3.3.4 Land-Based Wind Finance

Throughout 2011, the financing environment remained relatively steady for land-based wind development. The extension of the Section1603 cash grant program through 2011 allowed for continued flexibility in project developer's incentive election options between the 30% cash payment or tax incentive mechanisms, such as the production tax credit. This flexibility helped to ensure an adequate supply of tax equity investment capital.

The cost of capital for both term debt and tax equity investment in 2011 did not depart significantly from 2010 levels. For example, Tegen et al. (2012) reported that the term debt interest rate ranged from 5.8%–7.0% in 2010, while Mintz Levin reported a similar interest rate spread of 5.75%–7.25% in 2011 (Mintz Levin 2012). On the debt side, Wiser and Bolinger (2010) indicated that 6% interest of all-in debt rates were achievable in 2010 (Wiser and Bolinger 2011) and rates were at or below 6% again in 2011 (Wiser and Bolinger 2012), although loan lengths appeared to have shortened.

Because of the lack of large fluctuations in the cost and availability of debt and equity capital from 2010 to 2011, the financing assumptions were held constant from the previous land-based wind LCOE analysis. These assumptions will likely be revised in future editions of this report, based on the expiration of the Section1603 cash grant program and macroeconomic issues, such as new banking regulations or continued credit challenges in Europe.

3.4 Land-Based Wind Reference Project Summary

Table 5 captures the full array of variables that reflect the land-based reference project as well as the values (for each variable) that underlay the basic LCOE inputs. The all-in capital cost for the project is assumed to be nearly $419 million, or $2,098/kW. A $22.3 million contingency fund is assumed to cover any possible increases in capital costs, and AOE is estimated at $11/MWh, after tax. Operating life is assumed to be 20 years, with a nominal discount rate of 8%.

Table 5. Land-Based Reference Project Assumptions Summary

General Assumptions	
Project capacity (MW)	200
Number of turbines	133
Turbine capacity (MW)	1.5
Site	
Location	Heartland
Elevation (meters above sea level)	450
Layout	Grid
Wind speed (m/s at 50-m height above ground)	7.25
Wind speed (m/s at 80-m height above ground)	7.75
Net capacity factor	37%
Technology	
Rotor diameter (m)	82.5
Hub height (m)	80
Gearbox	Three-stage
Generator	Asynchronous
Foundation	Spread foot
Cost	
Capital cost (millions)	$418.60
Contingency (5%) (millions)	$22.30
AOE ($/MWh) after tax	$11
Discount rate (real)	5.70%
Discount rate (nominal)	8%
Operating life (years)	20
Fixed charge rate (real)	9.50%

Note: The nominal discount rate may be generally equated with the weighted average cost of capital and is distinguished from the real discount rate in that it includes an inflation factor. The discount rate constitutes a principal input into the fixed charge rate, which allows for the estimation of capital recovery on an annualized basis.

3.5 Land-Based Wind LCOE Calculation

Based on the NREL land-based baseline project inputs—ICC, AEP, AOE, and FCR—and using the LCOE equation, a land-based wind LCOE is computed to reflect the 2011 reference wind plant described above. Table 6 summarizes the costs for the primary components (including their contribution to LCOE). Data sources for this table are located in Appendix B. Figure 2 provides a graphical representation of the land-based reference project LCOE by line item.

Table 6. Land-Based LCOE Cost Breakdown

	1.5-MW Land-Based Turbine	1.5-MW Land-Based Turbine
ALL-IN CAPITAL COST	**$2,098/kW**	**$61/MWh**
Levelized replacement cost	$11/kW/yr	$3/MWh
Labor, equipment, facilities (O&M)	$17/kW/yr	$5/MWh
Land lease cost	$7/kW/yr	$2/MWh
ANNUAL OPERATING EXPENSES	**$35/kW/yr**	**$11/MWh**
Net 7.25 m/s AEP (MWh/MW/yr)	3263	
Net capacity factor	37%	
Fixed charge rate (real, after tax)	9.50%	
LEVELIZED COST OF ENERGY ($/MWh)	**$72**	

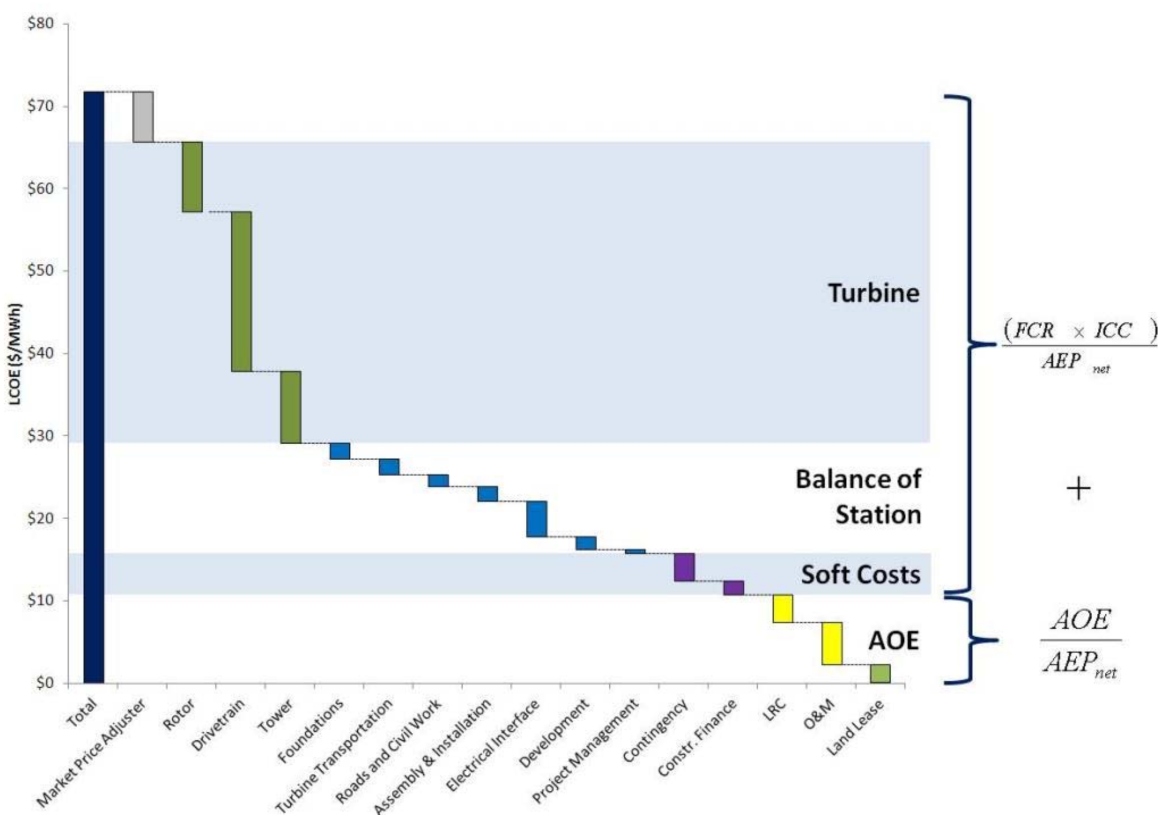

Figure 2. Line item cost breakdown for the 2011 land-based wind reference project

Source: NREL

3.6 LCOE Sensitivities

The input parameters described above reflect the reference wind project. However, input parameters for a near-term, land-based wind project are subject to considerable uncertainty. As a result, it is beneficial to investigate how this variability may impact LCOE. The sensitivity analysis shown in Figure 3 focuses on the basic LCOE inputs: 1) capital cost, 2) operating cost, 3) capacity factor (a surrogate for AEP), and 4) FCR, although in Figure 3, FCR is broken into its principal elements—discount rate and operational lifetime. Sensitivities to these variables are tested across the ranges of market data reported in previous sections.

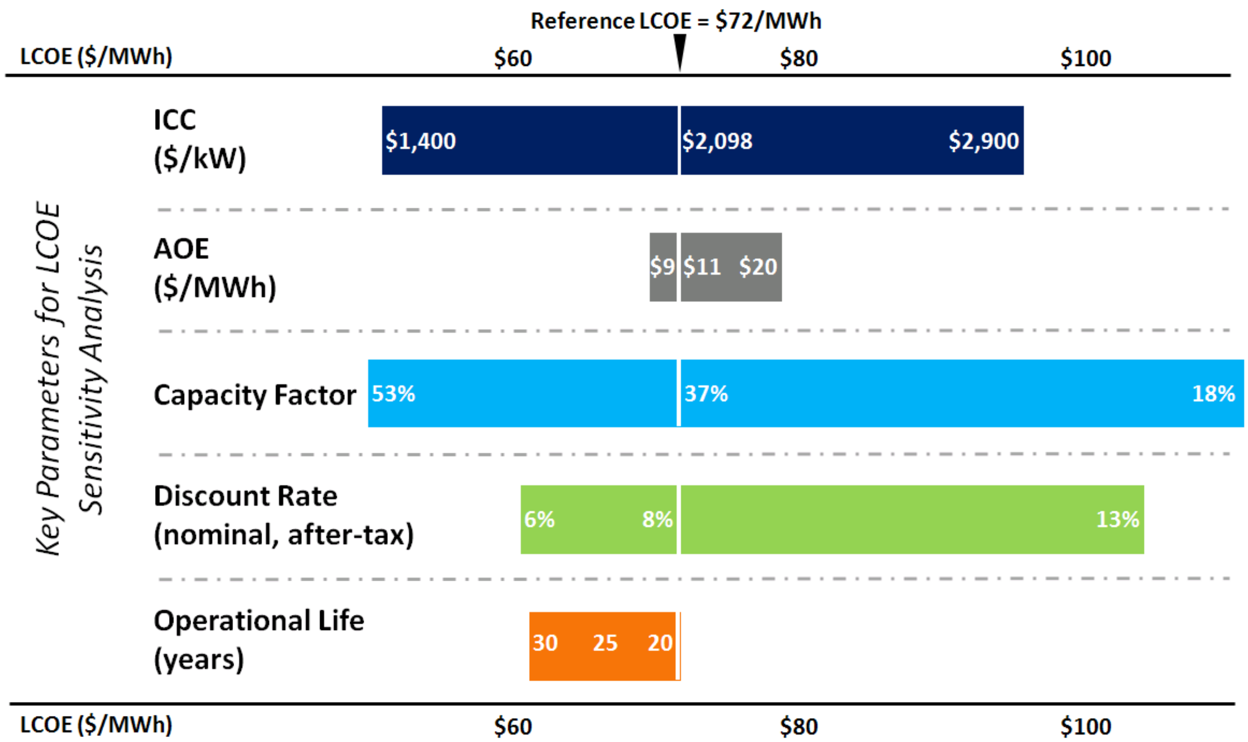

Figure 3. Sensitivity of land-based wind LCOE to key input parameters

Source: NREL

Note: The reference LCOE reflects a representative industry LCOE. Changes in LCOE for a single variable can be understood by moving to the left or right along a specific variable. Values on the X-axis indicate how the LCOE will change as a given variable is altered and all others are assumed constant (i.e., remain reflective of the reference project).

Sensitivity analyses were conducted by holding all reference project assumptions constant and altering only the variable in question. Sensitivity ranges were selected to represent the highs and lows observed in the industry. This selection of ranges provides insight into how real-world ranges influence LCOE. The sensitivity analysis yields ranges in LCOE from a low of $50/MWh to a high of $148/MWh—a low-to-high increase of nearly triple the lower bound. ICC and capacity factor have similar potential with respect to lowering LCOE; however, the capacity factor and discount rate show the highest influence with respect to an increase in LCOE relative to the reference project.

Although the ranges provided here for the selected variables are grounded in actual 2011 plant costs and performance data, the high and low LCOE ranges should not be taken as absolute. These variables are generally not independent, and it is unlikely for changes to only occur in a single variable. Moreover, each individual wind project has a unique set of characteristics. Accordingly, the sensitivities shown here are not universal.

3.7 Example Cost Reduction Scenarios

For the 2011 reference project installations, two additional scenarios were modeled: 1) decreased installed capital cost, and 2) increased annual average wind speed. Similar to the other sensitivities, this analysis was performed by holding all reference project assumptions constant and changing only one variable at a time.

3.7.1 Decreased Capital Cost

Wiser and Bolinger (2012) suggested that 2009/2010 represented a likely peak in installed capital cost based on 2011's slightly lower averages and estimates for 20 projects in 2012 that were reported to be even lower. With turbine prices peaking in 2008/2009 and continuing in a downward trend, it is reasonable to expect that installed capital cost would continue in a downward trend as well, because of the lag time between negotiations of turbine supply contracts, power purchase agreements, and project commissioning. If installed capital costs continue downward and match the initial 2012 estimated average reported by Wiser and Bolinger (2012) in midyear (approximately $1,750/kW), the reference project LCOE would be expected to fall to $62/kWh (Table 7).

3.7.2 Increased Annual Average Wind Speed

A number of factors, such as policy influences, siting impacts, and technology changes, have led to the recent trend in siting wind projects in areas of reduced wind resource quality (Wiser and Bolinger 2012). There is still a surplus of high-quality wind resource project sites that are undeveloped in the United States, and an effort to place more projects in these areas could lower LCOE. Table 7 presents the change in LCOE that is a direct result of switching from a Class 4 wind resource (annual average hub-height wind speed of 7.75 m/s) to a Class 5 wind resource (annual average hub-height wind speed of 8.29 m/s). It is important to note that the decrease in LCOE resulting from the better wind resource may also be achieved with a taller tower or a larger rotor for the same turbine power rating. If these technological advances can be implemented without a concurrent increase in either ICC or AOE (using advanced controls or design innovations), the net effect could be similar.

Table 7. Example Land-Based LCOE Reduction Scenarios

	Reference Project	Reduced ICC	Higher Annual Wind Speed
Installed capital cost ($/kW)	$2,098	$1,750	$2,098
AOE ($/kW/yr)	$35	$35	$35
Net annual energy production (MWh/MW/yr)	3,263	3,263	3,578
LCOE ($/MWh)	**$72**	**$62**	**$65**

4 Offshore Wind

Although there is much enthusiasm about the potential of offshore wind development in policy circles, no projects have been installed in U.S. waters to date. The lack of domestic experience with offshore wind technology has contributed to considerable uncertainty in estimates of the potential cost of offshore wind energy in the United States. The *2010 Cost of Wind Energy Review* (Tegen et al. 2012) offers a detailed analysis of offshore wind cost trends in Europe as well as projections for the United States to develop input assumptions for a reference project based on commercial-scale fixed-bottom offshore wind technology.

This report provides an update to the 2010 report including trends in capital costs observed outside of the United States as well as recent market conditions. However, as no major differences in offshore costs have been observed for projects under development in the United States, the cost estimates are consistent with those reported in the 2010 report (Tegen et al. 2012) (Table 8). Although information on floating offshore wind projects is not included here, it will be covered in future iterations of this report.

Table 8. Summary of Inputs and Results for the Fixed-Bottom Offshore Wind Project

Data Source		3.6-MW Offshore $/kW	3.6-MW Offshore $/MWh
Literature	Turbine capital cost	1,789	62
Market	Balance-of-station costs	2,918	101
Literature	Soft costs	893	31
Market	**INSTALLED CAPITAL COST**	**5,600**	**194**
Market	Annual operating expenses ($/kW/yr)	136	40
Market	Fixed charge rate (%)	11.8	
Model	Net annual energy production (MWh/MW/yr)	3,406	
Model	Capacity factor (%)	39	
	TOTAL LCOE ($/MWh)	**225**	

4.1 2011 Market Developments

In 2011, 966 MW of offshore wind capacity were installed worldwide (GWEC 2012). To date, offshore wind development has been highly concentrated, with over 93% of cumulative capacity installed in Europe (GWEC 2012). Installations in Asia are starting to accelerate, with two commercial-scale projects installed in China and three demonstration projects installed in South Korea and Japan. Global markets are poised for growth with aggressive goals in both Europe and Asia. However, deployments have been affected by uncertainty in the form and value of incentives (United Kingdom), delays in grid development (Germany), and local and national government concerns (China). In the United States, the following additional hurdles have been observed:

- **An uncertain timeline for permitting**. The Bureau of Ocean Energy Management took several steps in 2011 to define the process for leasing and permitting projects; however, this new process had not yet been demonstrated at the time of this study.
- **Potential inabilities to negotiate power purchase agreements**. Given the existing cost structure, offshore wind projects currently require above-market power prices for financial viability. The power purchase agreements (PPA) for offshore wind negotiated to date have been driven by state-level policies and/or regulatory intervention.
- **The scheduled expiration of the production tax credit**. The PTC, an incentive for renewable energy generation, was scheduled to expire at the end of 2012, but was extended for 1 year. Because of the multiyear development horizon for offshore wind projects, the short-term nature of the PTC (even in its recently extended form) will likely continue to impact the domestic offshore wind industry.

4.2 Installed Capital Cost for Fixed-Bottom Offshore Wind

For the *2010 Cost of Wind Energy Review*, NREL developed the offshore ICC estimate by conducting several parallel assessments: 1) analysis of global market data, 2) review of published literature, and 3) interviews with active offshore wind developers in the United States. This multipronged approach yielded an average capital cost of $5,120/kW across the industry (for operational and proposed plants worldwide) and resulted in a U.S. reference cost estimate of $5,600/kW (consistent with the ICC reported by the proposed Cape Wind offshore project situated off Cape Cod in Nantucket Sound). The reported range in installed capital costs (again for operational and proposed projects) varied from $2,500/kW to $6,500/kW.[11]

To inform the 2011 installed capital cost estimate, researchers updated and re-analyzed the NREL offshore wind project database (NREL 2013) (Figure 4). This database currently contains capital cost data for 98% of the total offshore wind capacity that had been fully commissioned by the end of 2011.[12] The database also contains capital cost estimates for 35 projects in Europe, the United States, and Asia that have received all of the necessary approvals from regulatory authorities to proceed with construction. This near-term project pipeline extends through 2016 and totals some 10,373 MW of capacity. The proposed Cape Wind project was the only U.S. project to have achieved regulatory approval by the end of 2011.

[11] Offshore wind capital costs may vary widely as a result of water depth, distance from shore, turbine size, and other factors.
[12] Capital costs and project data were collected from a variety of sources, including peer-reviewed literature, industry white papers, press releases, developer websites, and industry databases. Many cost estimates were self-reported figures from project developers and could not be independently verified. When there were multiple cost estimates for a given project, costs were averaged: 1 EUR = 1.392 USD; 1 GBP = 1.604 USD; 1 DKK = 0.187 USD; 1 SEK = .157 USD; 1 NOK = 0.165; and CNY = 0.155 USD (x-rates.com 2011).

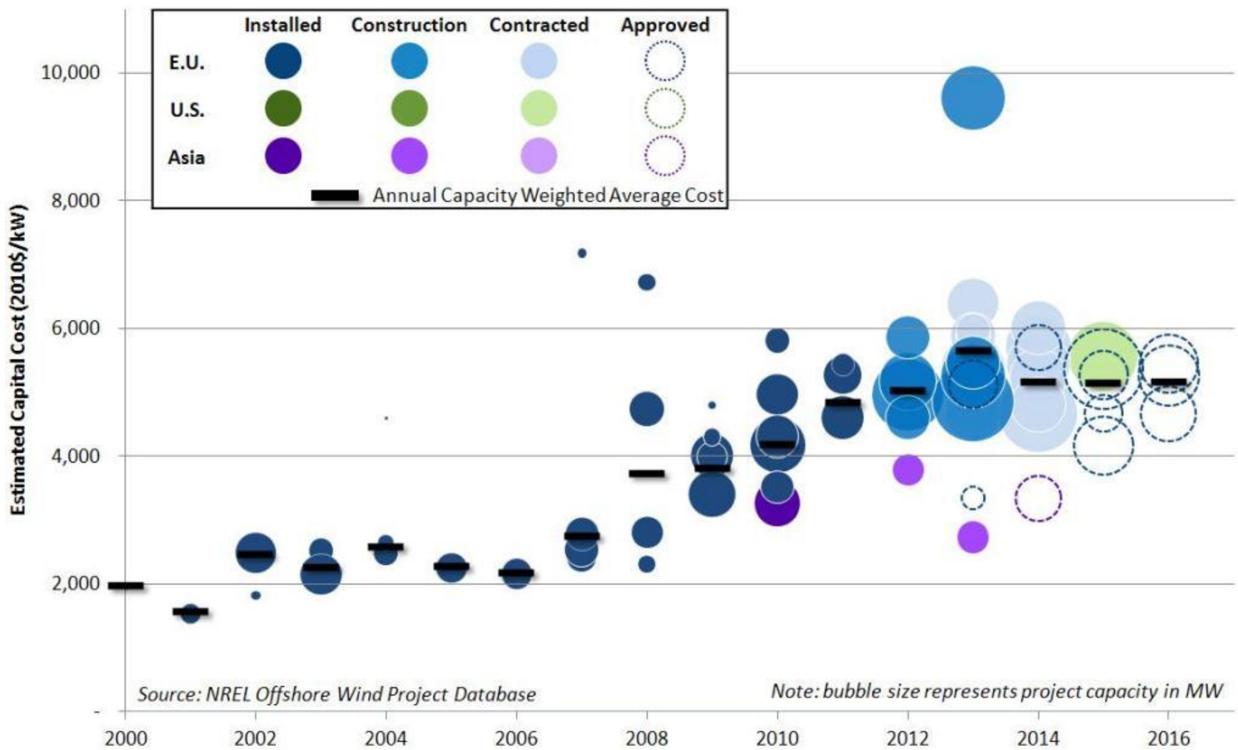

Figure 4. Reported capital costs for installed, under construction, contracted, and approved offshore wind projects (2000 to 2016)

Source: NREL

Note: Each circle represents an individual project either in operation or under development. Color-coding indicates the location for each project by market and its current status. Projects under development are plotted based on their anticipated commissioning date.

Globally, projects commissioned in 2011 had a capacity-weighted average capital cost of $4,839/kW, almost $700/kW higher than the average cost of a project installed in 2010. However, capital costs for the sample of planned projects that received regulatory approval through 2016 averaged $5,335/kW. This is within 4% of the industry average of $5,120/kW stated in the *2010 Cost of Wind Energy Review*, and suggests that the cost environment remained relatively consistent between 2010 and 2011. Moreover, the European 400-MW "BARD Offshore I" project (represented by the uppermost blue circle in Figure 4), with a reported capital cost of $9,630/kW, is a clear outlier on this chart and is likely not representative.[13] The project has reported cost overruns of $1.4 billion from the initial budget, or about 57%. This overrun amounts to additional costs of more than $3,300/kW. If the BARD Offshore I project is left out

[13]Developer BARD Holding GmbH, adopted a vertically integrated strategy to deliver this project, including the manufacturing of the offshore wind turbines and foundations as well as managing the construction. The pilot project was intended to help the company gain experience with the serial production of offshore wind turbines and foundations as well as offshore installation.

of the dataset, the capacity-weighted average capital cost falls to $5,178/kW, or within 1% of the industry average reported in the *2010 Cost of Wind Energy Review*.

Another interesting observation is that the planned Asian offshore wind projects are well below the range of costs expected for planned projects in either Europe or the United States. Although these lower cost estimates might partially be explained by lower costs for items like labor and manufacturing, others suggest that the developers of these projects may have been too optimistic in estimating capital costs (Patton 2012). As a result, these costs are unlikely to represent true future offshore wind projects in the United States.[14]

Based on the above data, capital cost estimates for global offshore wind projects have remained largely constant. Moreover, activity in the domestic wind market was relatively limited in 2011. The 468-MW Cape Wind project remains the most advanced offshore wind project in the United States and the only project to have obtained regulatory approval. Because the forward-looking global and domestic capital cost environment does not appear to have shifted, the reference project installed capital cost of $5,600/kW is maintained with the range of estimates for commercial-scale projects[15] that received regulatory approval, excluding noted outliers, extending from approximately $4,500/kW to $6,500/kW.

Figure 5 shows the percentage contribution of each component to total capital cost for the reference offshore wind project. Percentage estimates are based on the NREL wind turbine design cost and scaling model (Fingersh et al. 2006, Maples et al. 2010); several recent publications (Douglas-Westwood 2010, BVG Associates 2011, Deloitte 2011); and conversations with U.S. offshore wind project developers. In Figure 1, the segment in green represents the turbine cost, shades of blue represent balance-of-station costs, and shades of purple represent soft costs.

[14] However, sourcing components from low-cost countries might offer a potential pathway for reducing capital costs.
[15] In this report, a commercial-scale project is defined as a project with a capacity greater than 50 MW.

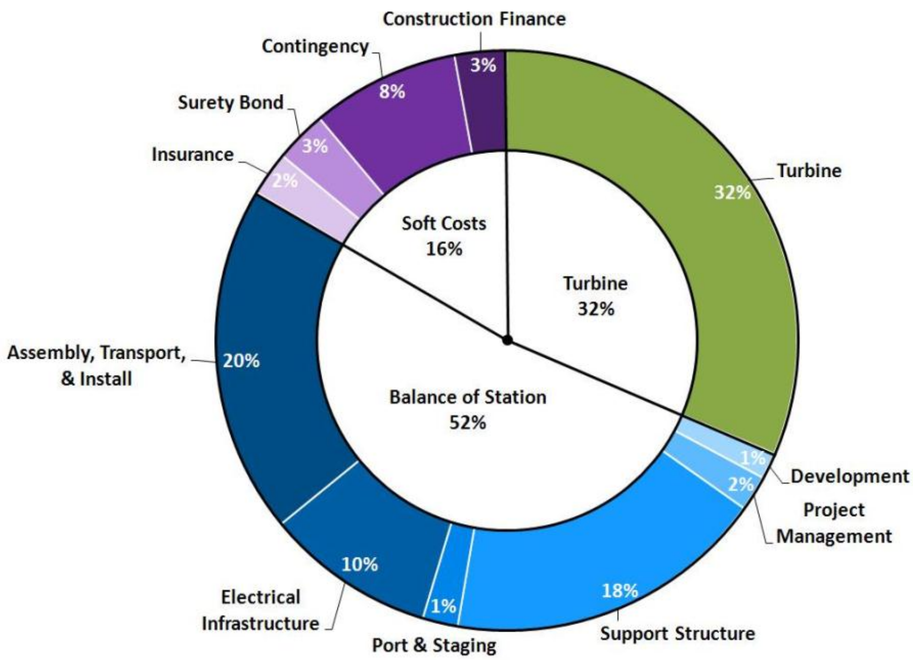

Figure 5. Installed capital costs for the 2010 offshore wind reference project

Source: NREL

The percentage estimates in Figure 5 were applied to the all-in capital cost estimate of $5,600/kW to generate individual component costs in dollars per kilowatt for the 2011 reference project. This dollar-value component cost breakdown is shown in Table 9. As stated, there is a notable difference between the cost components that make up the land-based and offshore projects. In the land-based project, 68% of the cost is related to the turbine; whereas, with the offshore project, the turbine makes up only 32% of the ICC.

Table 9. Fixed-Bottom Offshore LCOE Component Cost Breakdown

	3.6-MW $/kW	3.6-MW $/MWh
TURBINE CAPITAL COST	**1,789**	**62**
Development (i.e., permits, engineering, and site assessment)	58	2
Project management	117	4
Support structure	1,021	35
Port and staging	73	3
Electrical infrastructure	540	19
Transportation and installation	1,109	38
BALANCE OF STATION	**2,918**	**101**
Insurance	94	3
Surety bond (decommissioning)	165	6
Contingency	471	16
SOFT COSTS	**730**	**25**
OVERNIGHT CAPITAL COST	**5,437**	**188**
CONSTRUCTION FINANCING COST	**163**	**6**
ALL-IN CAPITAL COST	**5,600**	**194**

4.3 Annual Operating Expenses for Offshore Wind

There has been no indication that expected annual operating expenses for offshore wind projects have shifted between 2010 and 2011. The AOE baseline for 2011 is assumed to be $31/MWh, equivalent to $107/kW/yr, with a range extending from $9/MWh to $55/MWh, based on data reported by Tegen et al. (2012).

4.4 Offshore Annual Energy Production and Capacity Factor

Wiser et al. (2011) reported that installed European offshore wind projects typically achieve capacity factors between 35% and 45%. Rødsand II, a Danish project installed in 2010, reported a capacity factor of 55% in its first year of operation. U.S. developers have announced capacity factor expectations for nine project sites currently under development. Data collected by NREL suggests that net capacity factors at these projects range from 32% to 42%, with an average of 38% (NREL 2013).

Because net AEP and the corresponding net capacity factor will vary with the wind resource and project design, we assume specific site characteristics that are common to the North Atlantic Coast for the reference offshore wind project. AEP for this analysis is calculated using the NREL wind turbine design cost and scaling model and a Class 6 wind resource. Table 10 shows the assumptions used to calculate the net AEP for the reference project.

Table 10. Fixed-Bottom Reference Offshore AEP Input Assumptions

Turbine Parameters	
Turbine rated power (MW)	3.6
Turbine rotor diameter (m)	107
Turbine hub height (m)	90
Maximum rotor tip speed (m/s)	90
Tip-speed ratio at coefficient of performance (C_p)	8
Drivetrain design	Geared
Rotor peak Cp	0.47
Wind Resource Characteristics	
Annual average wind speed at 50 m (m/s)	8.4
Weibull K	2.1
Shear exponent	0.1
Losses	
Losses (array, energy conversion, line)	15%
Availability	96%

We, the NREL authors, also assume that offshore wind projects will experience losses from array impacts, availability, and inefficiencies in power collection and transmission. Assuming 18% total losses, AEP_{net} is estimated for offshore wind projects using commercially available technology and the NREL wind turbine design cost and scaling model. Table 11 shows the impact of losses on AEP and capacity factor.

Table 11. Offshore Wind Turbine AEP and Capacity Factor Summary

	3.6-MW Offshore
Gross AEP (MWh/MW/yr)	4,174
Gross capacity factor (%)	48
Losses and availability (%)	18
Net AEP (MWh/MW/yr)	3,406
Net capacity factor (%)	39

These data show that the 2011 baseline project will deliver 3,406 MWh per megawatt of installed capacity annually, which is equivalent to a net capacity factor of 39%. The range of AEP estimates around this baseline extends from 2,600 to 4,820 MWh/MW/year, which corresponds to the range of capacity factors (30%–55%) observed in Europe and for planned projects in the United States.

4.5 Financial Parameters for Offshore Wind

There has been no indication that financial parameters for domestic offshore wind projects have changed between 2010 and 2011. The reference project discount rate for 2011 is assumed to be 10.5%, with a range extending from 8% to 15%, based on data reported by Tegen et al. (2012).

4.6 Offshore Wind Reference Project Summary

The databases and analysis described above informed the creation of the reference project shown in Table 12. The 2011 reference project is defined with 139 turbines on monopile foundations and an average water depth of 15 m. Reference project costs are based on estimates for a site situated 20 km from shore. In addition, turbines rated at 3.6 MW, with a 107-m rotor diameter and a 90-m hub height are assumed. The average wind speed at the project site is assumed to be 8.4 m/s at 50 meters and 8.9 m/s at the 90-m hub height (Class 6 wind regime).[16] In the reference project layout, the turbines are spaced at 8 rotor diameters apart and connected to the substation using a simple radial 33-kilovolt (kV) collection system design.

The installed capital cost of the project is assumed to be $2.8 billion, or about $5,600/kW, including a contingency estimated at 10% of hard costs. After tax, annual operating expenses are equivalent to $31/MWh, or $385,000 per turbine per year.

The weighted average cost of capital (WACC), or discount rate, used to finance the project is estimated to be 10.5% nominal (equivalent to 8.1% real). Although this discount rate could represent a number of different financial structures, the specific structures are not examined in this analysis. The reference project is assumed to have an operating life of 20 years from the date of commissioning. The fixed charge rate under these assumptions is 11.8%.

[16]Average wind speed based on a Weibull (k = 2.1) probability distribution.

Table 12. Fixed-Bottom Offshore Reference Project Assumptions Summary

General Assumptions	
Project capacity (MW)	500
Number of turbines	139
Turbine capacity (MW)	3.6
Site	
Location	North Atlantic Coast (U.S.)
Depth (m)	15
Distance from shore (km)	20
Wind speed (m/s at a 50-m elevation)	8.4
Wind speed (m/s at a 90-m elevation)	8.9
Net capacity factor	39%
Technology	
Rotor diameter (m)	107
Tower height (m)	90
Gearbox	Three-stage
Generator	Asynchronous
Foundation	Monopile
Cost	
Capital cost (millions)	$2,800
Contingency (10% of hard costs)(millions)	$236
AOE ($/MWh)	$40
Discount rate (real)	8.10%
Discount rate (nominal)	10.50%
Operating life (years)	20
Fixed charge rate (real)	11.80%

4.7 Offshore Wind LCOE Calculation

Table 13 summarizes the offshore wind technology reference project by providing the component cost categories for the 3.6-MW turbines in the project as well as the LCOE calculation results. A comprehensive summary of assumptions can be found in Appendix B. Estimates of the percentage contribution of individual project components to total capital costs are developed for each component based on the aforementioned publications and conversations. These estimates are applied to the total capital cost estimate to generate individual component costs. NREL plans to continue to collect market data and develop bottom-up cost models in 2013. These data and models will enable the development of an improved understanding of scaling relationships and opportunities for technology improvement, and to reflect current market data in 2013.

Table 13. Fixed-Bottom Offshore Wind LCOE and Reference Project Cost Breakdown

	3.6-MW Offshore Turbine	3.6-MW Offshore Turbine
ALL-IN CAPITAL COST	$5,600/kW	$194/MWh
Levelized replacement cost	$40/kW/yr	$12/MWh
Labor, equipment, and facilities (O&M)	$46/kW/yr	$22/MWh
Outer Continental Shelf lease cost	$21/kW/yr	$6/MWh
ANNUAL OPERATING EXPENSES	**$107/kW/yr**	**$40/MWh**
Net 8.0 m/s AEP (MWh/MW/yr)	3,406	
Capacity factor	39%	
Fixed charge rate (real, after tax)	11.80%	
LEVELIZED COST OF ENERGY ($/MWh)	**225**	

The 2011 NREL reference offshore wind project has an LCOE of $225/MWh. Figure 6 shows the cost breakdown for the project. It is unchanged from the reference project described in Tegen et al. (2012).

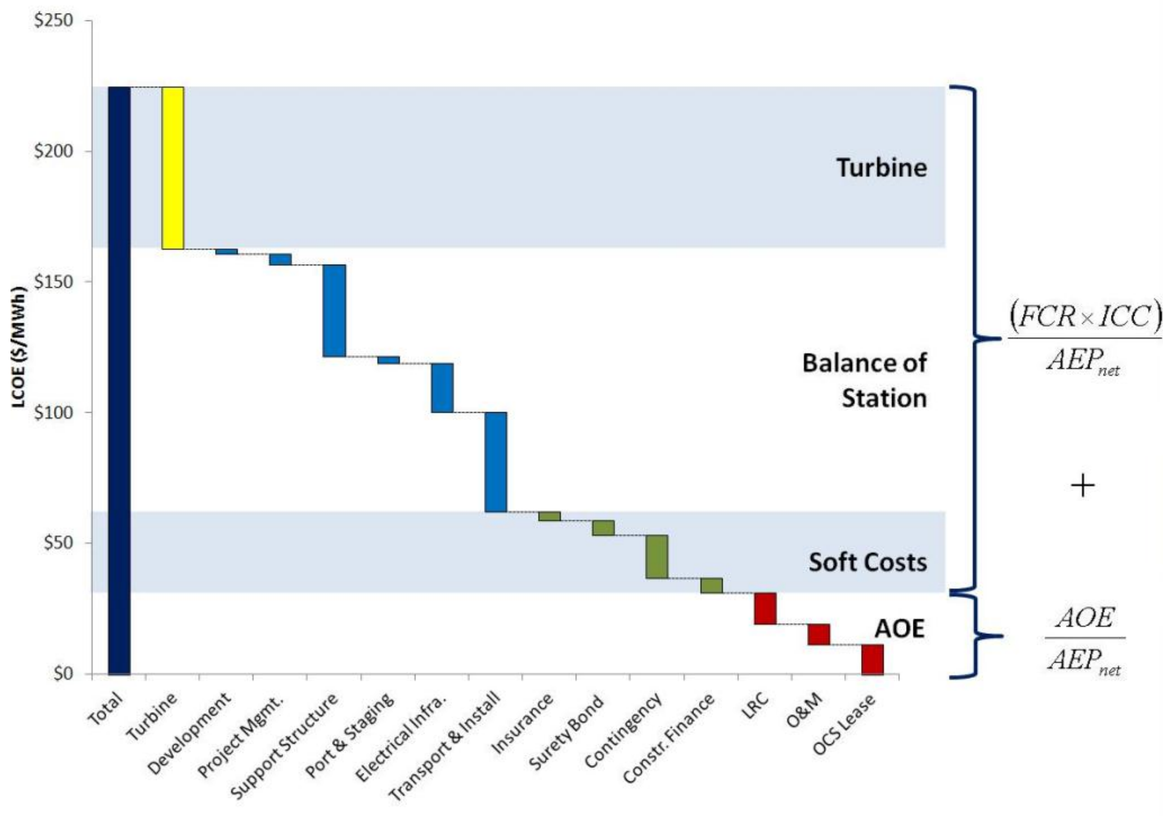

Figure 6. Cost breakdown for the 2011 offshore wind reference project

Source: NREL

4.8 Offshore Wind LCOE Sensitivities

Although the input parameters used for the LCOE calculation in the reference project represent reasonable estimates for the costs and operational parameters of a near-term offshore wind project, as was the case for land-based projects, these inputs are subject to considerable uncertainty. The sensitivity analysis shown in Figure 7 focuses on the basic LCOE inputs: 1) capital cost, 2) operating cost, 3) capacity factor (a surrogate for AEP), and 4) FCR, although in Figure 7, discount rate and operational lifetime represent FCR. Sensitivities were tested using the observed ranges described above and by holding all other variables constant. In Figure 7, the reference estimate for each parameter is represented by the white line within each bar, and specific high and low values are shown within each colored bar.

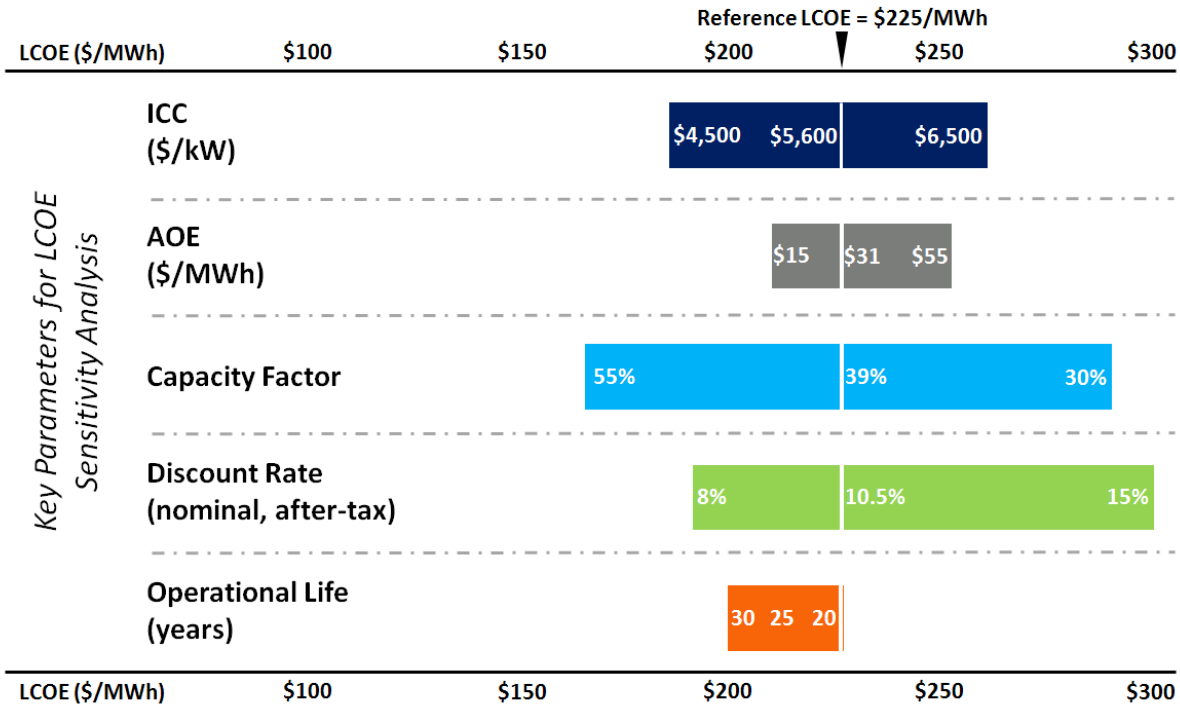

Figure 7. Sensitivity of offshore wind LCOE to key input parameters

Source: NREL

Note: The reference LCOE provides a representative estimate of the offshore wind LCOE, assuming commercial-scale fixed-bottom technology. Changes in LCOE for a single variable can be understood by moving to the left or right along a specific variable. Values on the X-axis indicate how the LCOE will change as a given variable is altered and assuming that all others are constant (i.e., the variables remain reflective of the reference project).

During the analysis, sensitivity ranges are selected to represent the highs and lows seen in the industry. This selection of ranges provides insight into how real-world ranges influence LCOE. Figure 7 shows a very wide range of LCOE outcomes, extending from $168 to $292/MWh. However, as noted above in the discussion of land-based sensitivities, the high and low LCOE ranges should not be taken as absolute because these variables are not typically independent. For offshore wind projects, cost of energy is most sensitive to capital cost, operating costs, and discount rate, and appears to be least sensitive to operating life and operating costs.

5 Conclusions

This analysis presents a picture of the levelized cost of land-based and offshore wind energy using real and modeled data that represents 2011 market conditions. Scenario planning and modeling activities often focus on one number (or cost) for land-based LCOE and one for offshore LCOE. In reality, the cost of land-based wind energy varies greatly across the United States and offshore wind LCOE varies significantly across Europe and Asia (Table 14).

The LCOE analysis presented in this report is only one way to measure the cost of wind energy, and it does not include other costs and issues that influence a given wind project's viability, such as transmission, environmental impacts, and military constraints, or other areas of consideration (e.g., public policy, consumer costs, energy prices, or public acceptance). In addition, these LCOE estimates do not reflect the value of electricity, incentives, or other policy mechanisms (such as production tax credits or investment tax credits) that affect the sales price of electricity produced from wind projects.

Table 14. Ranges of LCOE and LCOE Elements for Land-Based and Offshore Wind in 2011

	Land-Based	Offshore
Installed capital cost	\$1,400–\$2,900/kW	\$4,500–\$6,500/kW
Annual operating expenses	\$9–\$18/MWh	\$15–\$55/MWh
Capacity factor	18%–53%	30%–55%
Discount rate	6%–13%	8%–15%
Operational life	20–30 years	20–30 years
Range of LCOE	<\$60–>\$100/MWh	<\$168–>\$292/MWh

6 Related and Future Work

NREL continues to work to gain a better understanding of costs associated with many components of land-based wind turbines and systems. Continued collaboration with industry could lead to better data, enhanced modeling capabilities, and increased awareness of current and future wind power system component costs. For offshore wind, this analysis provides a best estimate for potential domestic wind power projects.

NREL updates this review of wind energy costs on an annual basis. These updates are intended to help maintain a perspective on costs that is grounded in real-time market changes as well as offer greater insight into the costs and performance of individual components related to the wind generation system. In addition, these reports are intended to provide greater clarity regarding wind energy costs and the effects of changes in specific variables on the levelized cost of energy (LCOE). The data and tools developed will be used to help inform projections, goals, and improvement opportunities. As the industry evolves and matures, NREL will continue to release current representative project data and LCOE estimates for scenario planning, modeling, and goal setting.

Future work entails three primary objectives: 1) continue to enhance data representing market-based costs, performance, and technology trends to reflect actual wind industry experience, 2) enhance the fidelity of bottom-up cost and performance estimation for individual wind plant components, and 3) understand sensitivities to factors such as regional differences, site characteristics, and technology choices. In 2012 and going forward, NREL will continue to work with industry and national laboratory partners to obtain project-specific data to validate and improve models. NREL's ongoing wind analysis efforts include:

- Research that focuses on understanding current and historical operation and maintenance costs, including major component replacement costs
- Creating a model to better represent land-based and offshore non-turbine project costs, such as foundations, electrical cabling, and installation, across a range of turbine and project sizes
- Developing a wind energy systems engineering model to conduct enhanced analysis of new innovation impacts on turbine cost and performance.

In addition, NREL plans to:

- Estimate the effect on LCOE from anticipated improvements to operation and maintenance in both land-based and offshore wind projects
- Determine the magnitude and effect of wake losses
- Quantify the effect of potential technology pathways on system LCOE for land-based and offshore wind technology
- Collect data and examine key issues involved in wind power deployment, such as transmission, radar, wildlife issues, and public acceptance, to better understand their impacts on the cost of wind energy and potentially developable land
- Assess small and midsize wind technology costs.

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Appendix A. Present Value of Depreciation Calculations

Land-Based Wind

Table A1. Present Value of Depreciation Calculation for Land-Based Wind Reference (*d* = 8%)

Year	Net Book Value	5-Year MACRS Depreciation Schedule	Depreciation	Present Value Depreciation	Accumulated Present Value Depreciation
1	100	20.00%	20	18.5	18.5
2	80	32.00%	32	27.4	46
3	48	19.20%	19.2	15.2	61.2
4	28.8	11.52%	11.52	8.5	69.7
5	17.28	11.52%	11.52	7.8	77.5
6	5.76	5.76%	5.76	3.6	81.1

MACRS: Modified Accelerated Cost Recovery System

Offshore Wind

Table A2. Present Value of Depreciation Calculation for Offshore Wind Reference (*d* = 10.5%)

Year	Net Book Value	5-Year MACRS	Depreciation	Present Value Depreciation	Accumulated Present Value Depreciation
1	100	20.00%	20	18.1	18.1
2	80	32.00%	32	26.2	44.3
3	48	19.20%	19.2	14.2	58.5
4	28.8	11.52%	11.52	7.7	66.3
5	17.28	11.52%	11.52	7	73.3
6	5.76	5.76%	5.76	3.2	76.4

Appendix B. Summary of Assumptions for 2011 Reference Projects

Land-Based Wind Project Assumptions

Table B1. Comprehensive List of Assumptions for Land-Based Wind Reference Project Cost of Energy

Assumption	Units	Value	Notes
Project Information			
Capacity	Megawatts (MW)	200	Calculation
Number of turbines	#	133	Representative of commercial-scale projects
Turbine capacity	MW	1.5	Most common turbine size in the United States
Net capacity factor	%	37	Class 4 wind resource [7.25 meters per second (m/s) at 50 m], assumed losses (17%)
Rotor diameter	m	82.5	Most common rotor size of GE-1.5
Tower height	m	80	Average U.S. hub height
Operational life	years	20	Standard business case assumption
Installed Capital Costs (ICC)			
ICC (million)	$	418.6	Calculation
Installed capital costs	$/kW	2,098	Average ICC of 2011 U.S. projects
Market price adjustment	$/kW	195	Calculated to bring ICC in line with market conditions
Hard costs			Estimated based on the NREL wind turbine design cost and scaling model (Fingersh et al., 2006, Maples et al., 2010), NREL's new balance-of-station model, and NREL's conversations with developers of land-based wind projects in the United States
Turbine	$/kW	1,286	
Balance of station	$/kW	446	
Soft costs			
Construction finance	$/kW	60	
Contingency	$/kW	112	
Annual Operating Expenses (AOE)			
AOE costs	($/MWh)	11	Representative of published literature and NREL's conversations with U.S. land-based wind developers
AOE costs	($/kW/yr)	35	
Levelized replacement cost (LRC)	($/kW/yr)	11	
Operation and maintenance (O&M)	($/kW/yr)	17	
Land lease	($/kW/yr)	7	
Financing Costs [d, Fixed Charge Rate (FCR)]			
Inflation rate	%	2.2	Assumption in the 2011 Annual Energy Outlook (EIA 2011)
Discount rate (nominal)	%	8	2010 land-based weighted average cost of capital averages
Discount rate (real)	%	5.7	
FCR (nominal)	%	11.4	Calculation
FCR (real)	%	9.5	
Cost Recovery Factor (CRF) (nominal)	%	10.2	
CRF (real)	%	8.5	
Taxes (T)			
Effective	%	38.9	Calculation
Federal	%	35	Standard federal corporate tax rate
State	%	6	Representative state tax rate
Depreciation (PVDep)			
Depreciable basis	%	100	Simplified depreciation schedule
Depreciation schedule	5-yr MACRS		Standard for choice for renewable energy projects
Present value (PV) depreciation	%	81.1	Calculation
LCOE	**$/MWh**	**72**	**Calculation**

Offshore Wind Project Assumptions

Table B2. Comprehensive List of Assumptions for Offshore Wind Reference Project Cost of Energy

Assumption	Units	Value	Notes
Project Information			
Capacity	MW	500	Representative of commercial-scale projects
Number of turbines	#	139	Calculation
Turbine capacity	MW	3.6	Representative of turbine size planned for Cape Wind
Depth	m	15	Representative of proposed U.S. projects
Distance from shore	km	20	Representative of proposed U.S. projects
Net capacity factor	%	39	Class 6 wind resource (8.4 m/s @ 50 m), assumed losses (18%)
Rotor diameter	m	107	Representative of turbine size planned for Cape Wind
Tower height	m	90	Representative of turbine size planned for Cape Wind
Operational life	years	20	Standard business case assumption
Installed Capital Costs (ICC)			
ICC ($)	$ millions	2,800	Calculation
ICC	$/kW	5,600	Announced U.S. projects (recent), conversations with developers
Hard Costs			Percentages estimated based on the NREL wind turbine design cost and scaling model (Fingersh et al. 2006, Maples et al. 2010), several recent publications (Douglas-Westwood 2010, BVG Associates 2011, Deloitte 2011), and NREL's conversations with developers of offshore wind projects in the United States; percentage estimates applied to ICC estimate to obtain dollar-per-kilowatt values
Turbine	$/kW	1,789	
Development	$/kW	58	
Project management	$/kW	117	
Support structure	$/kW	1,021	
Port and staging	$/kW	73	
Electrical infrastructure	$/kW	540	
Transport and install	$/kW	1,109	
Soft Costs			
Insurance during construction	$/kW	94	
Decommissioning bond	$/kW	165	
Construction finance	$/kW	163	
Contingency	$/kW	471	
Annual Operating Expenses (AOE)			
AOE Costs	($/MWh)	40	Representative of published literature and NREL's conversations with U.S. offshore wind developers
AOE Costs	($/kW/yr)	107	
LRC	($/kW/yr)	40	Representative of published literature and NREL's conversations with U.S. offshore wind developers
O&M	($/kW/yr)	46	
Outer Continental Shelf (OCS) Lease	($/kW/yr)	21	Cape Wind OCS lease—2% operational revenue in years 1–15, 7% of operational revenue in years 15–20
Financing Costs (d, FCR)			
Inflation rate	%	2.2	Assumption in EIA's 2010 Annual Energy Outlook
Discount rate (nominal)	%	10.5	Approximate weighted average cost of capital for Cape Wind and Block Island wind projects
Discount rate (real)	%	8.1	
FCR (nominal)	%	13.9	Calculation
FCR (real)	%	11.7	
CRF (nominal)	%	12.2	
CRF (real)	%	10.3	
Taxes (T)			
Effective	%	38.9	Calculation
Federal	%	35	Standard federal corporate tax rate
State	%	6	Representative state tax rate
Depreciation (PVDep)			
Depreciable basis	%	100	Simplified depreciation schedule
Depreciation schedule	5-yr MACRS		Standard choice for renewable energy projects
PV depreciation	%	77.8	Calculation
LCOE	**$/MWh**	**225**	**Calculation**