Work Package 1
Final Report

IEA Wind Task 26

Multi-national Case Study of the Financial Cost of Wind Energy

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iea wind

NATIONAL RENEWABLE ENERGY LABORATORY

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Technical Report
NREL/TP-6A2-48155
March 2011

Contract No. DE-AC36-08GO28308

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Executive Summary

The lifetime cost of wind energy is comprised of a number of components including the investment cost, operation and maintenance costs, financing costs, and annual energy production. Accurate representation of these cost streams is critical in estimating a wind plant's cost of energy. Some of these cost streams will vary over the life of a given project. From the outset of project development, investors in wind energy have relatively certain knowledge of the plant's lifetime cost of wind energy. This is because a wind energy project's installed costs and mean wind speed are known early on, and wind generation generally has low variable operation and maintenance costs, zero fuel cost, and no carbon emissions cost. Despite these inherent characteristics, there are wide variations in the cost of wind energy internationally, which is the focus of this report.

Using a multi-national case-study approach, this work seeks to understand the sources of wind energy cost differences among seven countries under International Energy Agency (IEA) Wind Task 26 – Cost of Wind Energy. The participating countries in this study include Denmark, Germany, the Netherlands, Spain, Sweden, Switzerland, and the United States. Due to data availability, onshore wind energy is the primary focus of this study, though a small sample of reported offshore cost data is also included.

This report consists of two principal components. First, an overview and cross-country comparative analysis of the cost of wind energy is presented. The report then proceeds with a series of country-specific case studies that describe the unique cost elements of a typical wind energy facility in each of the represented countries.

For this analysis, we considered the levelized cost of energy (LCOE) as the primary metric for describing and comparing wind energy costs from country to country. The LCOE represents the sum of all costs over the lifetime of a given wind project, discounted to present time, and levelized based on annual energy production. The LCOE does not include any residual costs or benefits incurred beyond the project's assumed operational life.

The levelized cost of energy may be calculated using several methods. This report summarizes two perspectives and approaches: a high level scenario planning approach and a sophisticated financial cash flow analysis approach. The majority of the analysis in this report, however, focuses on the financial cash flow analysis approach; thus, it represents the perspective of a private investor in a wind energy project in each of the participating countries.

This analysis used a spreadsheet-based cash flow model developed by the Energy Research Centre of the Netherlands (ECN) to estimate the LCOE. The ECN model is a detailed discounted cash flow model used to represent the various cost structures in each of the participating countries from the perspective of a domestic financial investor in a wind energy project. The ECN model has been customized in this analysis to exclude country-specific wind energy incentives, resulting in unsubsidized LCOE estimates.

Results of the analysis indicate that the unsubsidized LCOE varies considerably among countries represented in this study. As shown in Table ES-1, the country-specific LCOEs range from €61/MWh ($85/MWh) in Denmark to €120/MWh ($167/MWh) in Switzerland.[1]

Table ES-1. 2008 Onshore LCOE by country

LCOE €/MWh ($/MWh)	
Switzerland	120 (167)
Netherlands	94 (131)
Germany	85 (118)
Spain	83 (115)
Sweden	67 (93)
United States	65 (91)
Denmark	61 (85)

The magnitude of the unsubsidized LCOE variation has been attributed to differences in country-specific energy production, investment cost, operations cost, and financing cost. As expected, the largest LCOE impact from country to country was the anticipated energy production component that could be due to the inherent wind regime, site selection, wind turbine design, or other factors. Market forces such as electricity market structuring or the perception of risk in a wind project investment also impacted the LCOE through large variations in both capital expenditures and financing costs. Costs attributed to the operations of a wind project ranged broadly across countries and had a sizable LCOE impact as well, though caution with the reported data for operations and maintenance costs were common. The unique factors contributing to the variations in LCOE across countries are explored further in the comparative analysis and country-specific wind energy chapters of the report.

Lastly, an alternative approach to calculating LCOE is also briefly explored. For example, high-level planning scenarios may eschew a sophisticated discounted cash flow approach in favor of a simplified method to estimate LCOE. Under this simplified approach, assumptions for explicit financing terms and time-varying cash flows are not made, but instead a general discount rate is selected to represent all of the characteristics of the finance instrument. This more simplistic, high-level planning scenario approach minimizes the number of input parameters and the level of detail can facilitate LCOE comparisons among many different electric generation types. Therefore, the various methods in calculating LCOE require precise attention as to how, and from what perspective, the calculation is made, and comparisons should be made and interpreted carefully.

[1] Exchange rate of 1.39 USD/EUR is used in currency conversions.

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Chapter 1: Financial Cost of Wind Energy in Seven Countries

Introduction

In 2009, the European Union added 10,163 MW of new wind energy capacity while the United States added 9,994 MW (EWEA 2010, Wiser and Bolinger 2010). These capacity additions in 2009 represented the largest source of new electricity generation in the EU and the second largest in the U.S. (EWEA 2010, Wiser and Bolinger 2010). Globally, demand for wind-generated electricity has increased for a number of reasons including growing concern for carbon emission mitigation, security and supply issues with fossil-based fuels, and a host other factors.

The variability of the all-in cost of wind energy, however, may still be a barrier for increased deployment of wind energy across the globe. From the outset of project development, investors in wind energy have relatively certain knowledge of the plant's lifetime cost of wind energy. This is because a wind energy project's installed costs and mean wind speed are known early on, and wind generation generally has low variable costs, zero fuel cost, and no carbon emission costs. Even with these inherent characteristics, there are, however, wide variations in the cost of wind energy from project to project, within a country, and internationally. That is the focus of this effort.

Objective and Approach

Using a multi-national case-study approach, this work seeks to understand the source of wind energy cost differences across seven countries under International Energy Agency (IEA) Wind Task 26 – Cost of Wind Energy. The participating countries include Denmark, Germany, the Netherlands, Spain, Sweden, Switzerland, and the United States.

Assessing the cost of wind energy requires evaluation of a number of components including investment cost, operation cost, finance cost, and annual energy production, and how these cost streams vary over the life of the project. Representation of each of the different temporal cost parameters as a single descriptive value may be accomplished using a variety of methods and approaches. For this project, we considered the levelized cost of energy (LCOE) as the primary metric for describing and comparing wind energy costs. The LCOE represents the sum of all costs over the lifetime of a given wind project, discounted to the present time, and levelized based on annual energy production. Furthermore, the LCOE can be calculated with a number of different methods or approaches to represent several differing perspectives. This report describes two of these perspectives and approaches - a high level scenario planning approach and a sophisticated financial cash flow analysis approach.

The majority of the analysis in this report focuses on assessing the cost of wind-generated electricity, from the perspective of a private investor, in a given wind project, in each of the represented countries. More specifically, the LCOE analysis in this report represents the country-specific financial cost of wind energy for a domestic investor financing their project using the adopted model and methodology. It is important to note that the financial cost comparisons are not a socio-economic cost evaluation of wind energy (i.e., the cost to society of this particular form of energy).

When calculating the financial cost of wind energy, this analysis tabulates all of the expenditures required to install, operate, and finance a wind project. In addition to assessing the pure cost of wind energy, this analysis also describes the revenues and wind energy incentives that are available to wind project owners in each of the represented countries. Differences that arise in cost elements among the countries are identified.

This report begins with a brief description of the cost elements that comprise the levelized cost of energy. Then, the spreadsheet model developed under the auspices of this project is described. Based on the data provided by each represented country, a Reference Case is defined to provide a common point of comparison among countries. The cost elements from each country are compared to the Reference Case to identify the source of the differences in levelized cost of wind energy. The next section briefly identifies an alternative method, from the private investor perspective, to calculating levelized cost of wind energy. The report then presents different LCOE estimates, based on the cost elements defined in the Reference Case, to demonstrate the variability in LCOE associated with the different methods. Finally, each of the participating countries provided a chapter that summarizes the cost elements of a typical wind project in their country. These constitute the bulk of this report.

Levelized Cost of Wind Energy

Cost Elements

The principal components of the cost of wind energy include capital investment, operation and maintenance, and finance. Within each category, a number of elements are included and Appendix A describes the individual cost elements considered in this report.

Wind projects require a significant capital investment comprised of a number of other costs beyond the turbines alone. However, as shown in Table 1, approximately 75% of the total investment cost is associated with the cost of the wind turbines. Other costs include grid connection, foundations, installation, and construction-related expenses, summarized as percentages in Table 1-1. These are based on a selection of data from Germany, Denmark, Spain, and the UK. Decommissioning costs are set aside at the initiation of a project and these are included in the initial capital investment because they are required by some countries.

Table 1-1. Cost elements of wind project capital investment

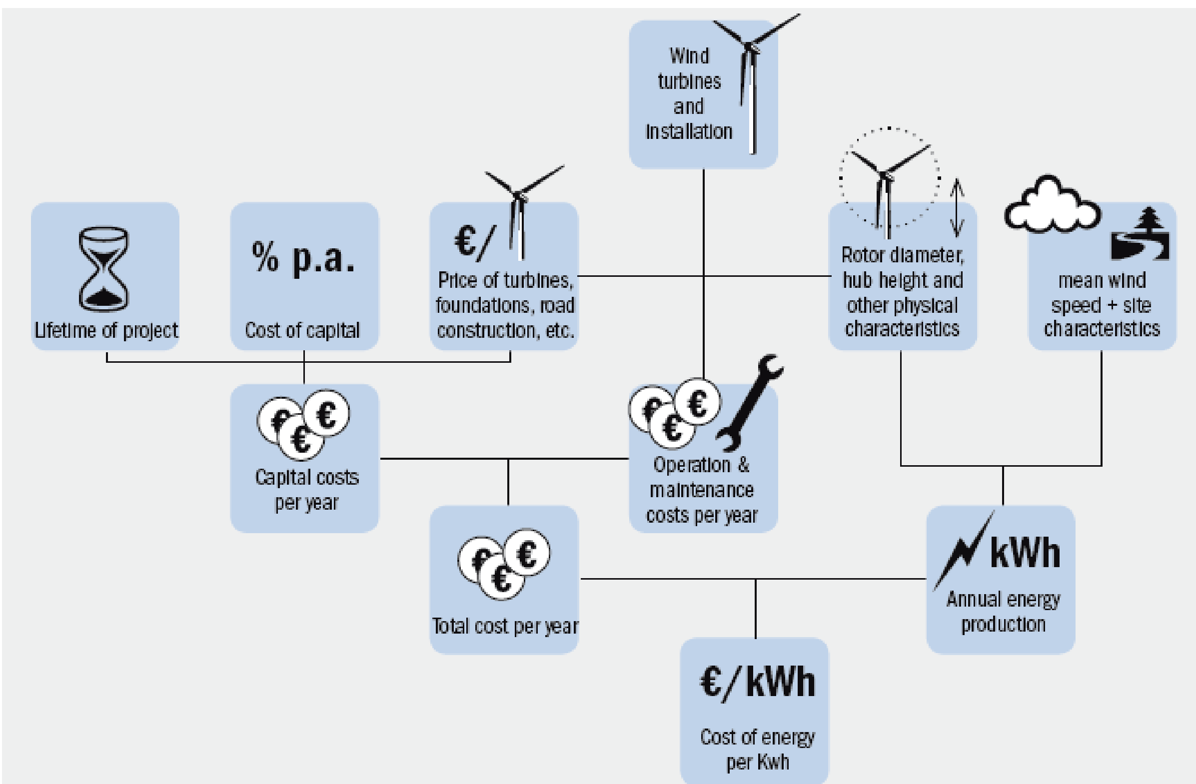
	Share of total cost (%)	Typical share of other cost (%)
Turbine (ex works)	68-84	-
Grid-connection	2-10	35-45
Foundation	1-9	20-25
Electric installation	1-9	10-15
Land	1-5	5-10
Financial costs	1-5	5-10
Road construction	1-5	5-10
Consultancy	1-3	5-10

Source: The Economics of Wind Energy, EWEA Report 2009

Operation and maintenance (O&M) costs contribute to the total cost of wind energy. A portion of these costs typically include fixed costs representing insurance, administration, and service contracts for scheduled maintenance. Variable O&M costs typically include scheduled and unscheduled maintenance and component replacement. These costs vary from one year to another; therefore, estimates often are made by assuming a constant cash flow stream over the life of the project. Since wind projects do not require annual fuel expenditures, O&M costs constitute the majority of annual costs. In some electricity markets, operating costs associated with power system services, such as reactive power compensation, are required for wind projects.

Finally, finance costs are a significant portion of the levelized cost of energy. The type of finance structures that are used to support construction of wind projects, and the associated levels of debt and equity contributors, vary among countries. The corresponding expected returns, by debt or equity investment providers, also vary significantly. In addition, each country's corporate tax structure influences the total financial costs associated with wind projects.

Figure 1-1 illustrates the various components included in an estimate of the cost of wind energy. The upfront investment costs, annual O&M costs, and financial variables are included. Because wind projects ultimately produce electricity, it is important to normalize the levelized cost with annual electricity production. Energy production depends on the wind turbines physical characteristics and the wind resource characteristics at a given project site.



Source: The Economics of Wind Energy, EWEA Report 2009

Figure 1-1. The cost of wind energy.

Revenues and Incentives

Electricity is the product sold by a wind project owner, and the markets for electricity vary by country. While this project focuses on the costs associated with generation of electricity from wind power plants, the revenues and incentives in each of the electric markets represented are summarized. In addition to revenue from electricity sales, a variety of incentives are employed to assure that the costs of wind-generated electricity are recovered. These incentives include feed-in tariffs, production-based tax credits, renewable energy certificates, or other mechanisms.

Externalities

A number of aspects to wind-generated electricity are not currently monetized and thus, are not included in an assessment of revenues or cost. These externalities, or societal costs, are associated with secondary impacts from electricity generation technologies. In general, renewable technologies have very low external impacts compared to conventional generation technologies. The IEA Renewable Energy Costs and Benefits for Society (RECaBS) project estimates the costs and benefits of electricity generation from renewable sources compared to those of conventional generators using a transparent methodology (RECaBs 2007). According to the ReCABS methodology, the analysis includes five externalities:

- "Climate change; greenhouse gasses, in particular CO_2 and CH_4
- Other air pollutants: SOx, NOx, and particles
- Grid integration; primarily added costs to the electrical infrastructure including power balancing costs and reduced capacity value of wind turbines
- Security of fuel supply; substitution of fuel imports with indigenous resources.

In addition to the externalities described above, electricity generation from wind does not rely on fuel consumption and the associated volatility of fuel prices. The investment risks for wind technology differ from the risk profile of fossil-fuel generation technologies. All of these characteristics create an important difference in the value proposition for wind technology relative to other generation technologies, but this study does not attempt to make such comparative assessments.

LCOE Model Description

The cash flow model developed by the Energy Research Centre of the Netherlands (ECN) forms the basis for the estimations of the LCOE and the financial gap (FG) for wind energy in this project. The ECN model is a discounted cash flow model, originally designed to calculate the feed-in premium subsidies for renewable electricity in the Netherlands. Currently, it is used by ECN to advise the Dutch government on the magnitude of the production costs for different renewable options. In the course of developing IEA Wind Task 26, the model has been tailored and extended to estimate cost structures in the participating countries. It is now a flexible, detailed tool for calculating the cost of wind energy. It contains modeling parameters such as unit size, operational time/full load hours, economic life, investment costs, O&M costs, project financing characteristics, and a wide range of additional relevant parameters. The model has been refined with more functionality and versatility when applying it to various countries and regulatory regimes, in general. For example, the revised cash flow model allows for adjustments to diverse technical and financial parameters, according to the respective regulatory regime of a wind power project. Such a flexible model is important, not only in the calculation of total investment costs, but also to account for the different operational features and financial instruments and incentives between countries and wind farms.

Basic Concept of the Model

A high level of detail in calculating the cost of wind energy can be achieved using the cash flow spreadsheet model, with its full range of parameters detailed in Appendix A. This spreadsheet model consists of six different worksheets. The first three worksheets provide the detailed information needed to calculate the cost wind energy in a specific country.

In the first worksheet, "Year-independent" variables can be set. These include project features, the total upfront investment costs, total decommissioning costs,[2] operational time in terms of full load hours, and the time horizon for the cost calculations. The investment and decommissioning costs can be given either as a total, or as a sum, of the various components. This is informative for cross-country comparisons of the differences in realized costs. In addition, a range of financial variables can be set in this worksheet. These include: inflation, to account for rising variable costs; return on debt; return on equity; and a debt/equity ratio, to reflect the financial risk associated with the project. Moreover, the cash flow model takes national and state corporate taxes into account.

The "Year-dependent" worksheet contains multiple entries that constitute the fixed and variable annual costs including O&M, land rent, and grid-related costs. Again, the detailed subdivision allows for cross-country comparison. Definitions for the electricity price and small determining factors, like contract and balancing costs, are provided.

In the third worksheet, labeled "Policies," the applicable feed-in tariffs, tax credits, and other incentives are considered. As an option within the model, the benefits associated with tax breaks can be limited to the project's cash flow or, alternatively, designated as unlimited.[3] The input parameters are used to determine the LCOE of the wind energy project, and the financial gap (FG) of electricity production, in the subsequent worksheets. The "Input_Output" worksheet presents the resulting LCOE and FG. It summarizes the variables used in the calculation. The actual cash flow calculations take place in the "Project cashflow" and "LCOE cashflow" worksheets.

LCOE and FG Calculations

The LCOE and FG result from cash flow calculations made from the perspective of a private financial investor; thus, the nominal after-tax return on equity is used as a discount rate for both LCOE and FG. However, the LCOE and FG include different streams of cash flows for each calculation. These are briefly described below.

LCOE is typically reported in terms of the investment outlays, annual costs, depreciation, and the chosen discount rate. Therefore, within this context, the LCOE calculation is defined as the production-dependent income required to achieve a zero net present value (NPV) of the equity share of the investment outlay, and the sum of all years' discounted after-tax cash flows. In the LCOE calculation, the cash flows related to income, from electricity production and/or wind energy incentives specific to wind energy, are not taken into account.

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[2] In the subsequent analysis, decommissioning costs were included only if they were required by a particular country to be set aside during project construction.

[3] In the subsequent analysis, all tax benefits were assumed to be "unlimited," meaning that sufficient cash flow exists to fully benefit from all available tax breaks.

The following formula is used in the ECN model's calculation of LCOE:

$$\boldsymbol{LCOE} =$$

$$\frac{\frac{Equity}{Share} \times \frac{Total}{Investment} + \sum_{t=1}^{T} \frac{(1 - Tax\ \ Rate) \times (Annual\ O\&M\ Outlays_t) - Tax\ Rate \times (Interest_t\ and\ Tax\ Depreciation_t)}{(1 + Return\ On\ Equity)^t}}{\sum_{t=1}^{T} \frac{Annual\ Electricity\ Produced_t \times\ (1 - Tax\ Rate)}{(1 + Return\ On\ Equity)^t}}$$

Conversely, in the FG calculation, cash flows from electricity production and financial incentives specific to wind energy (e.g., soft loans, upfront cash, or tax-based investment subsides) are now considered. Under this definition, the FG effectively represents the difference between a country's LCOE and the total realized income from the production of electricity and wind energy financial incentives.

The following formula is used in the ECN model's calculation of the FG:

$$\boldsymbol{FG} =$$

$$\frac{\frac{Equity}{Share} \times \frac{Total}{Investment} - \sum_{t=1}^{T} \frac{Annual\ Cash\ Flow\ After\ Taxes_t}{(1 + Return\ On\ Equity)^t}}{\sum_{t=1}^{T} \frac{Annual\ Electricity\ Produced_t \times\ (1 - Tax\ Rate)}{(1 + Return\ On\ Equity)^t}}$$

As described above, *Annual Cash Flow After Taxes* includes revenue from electricity sales, wind energy subsidies, rebates and incentives, annual O&M costs, amortization of loans, interest payments, and the cash flows from the after-tax value of tax depreciation and interest deductions.

Figure 1-2 illustrates the relation between the LCOE, the generated income (e.g., electricity market revenues, feed-in tariff, or feed-in premium), incentives, and the financial gap. As shown in Figure 1-2, the FG is defined such that a positive FG value corresponds to an insufficient amount of income necessary to cover the project developer's LCOE. Conversely, a negative FG value implies that a sufficient amount of income is generated to cover the LCOE.

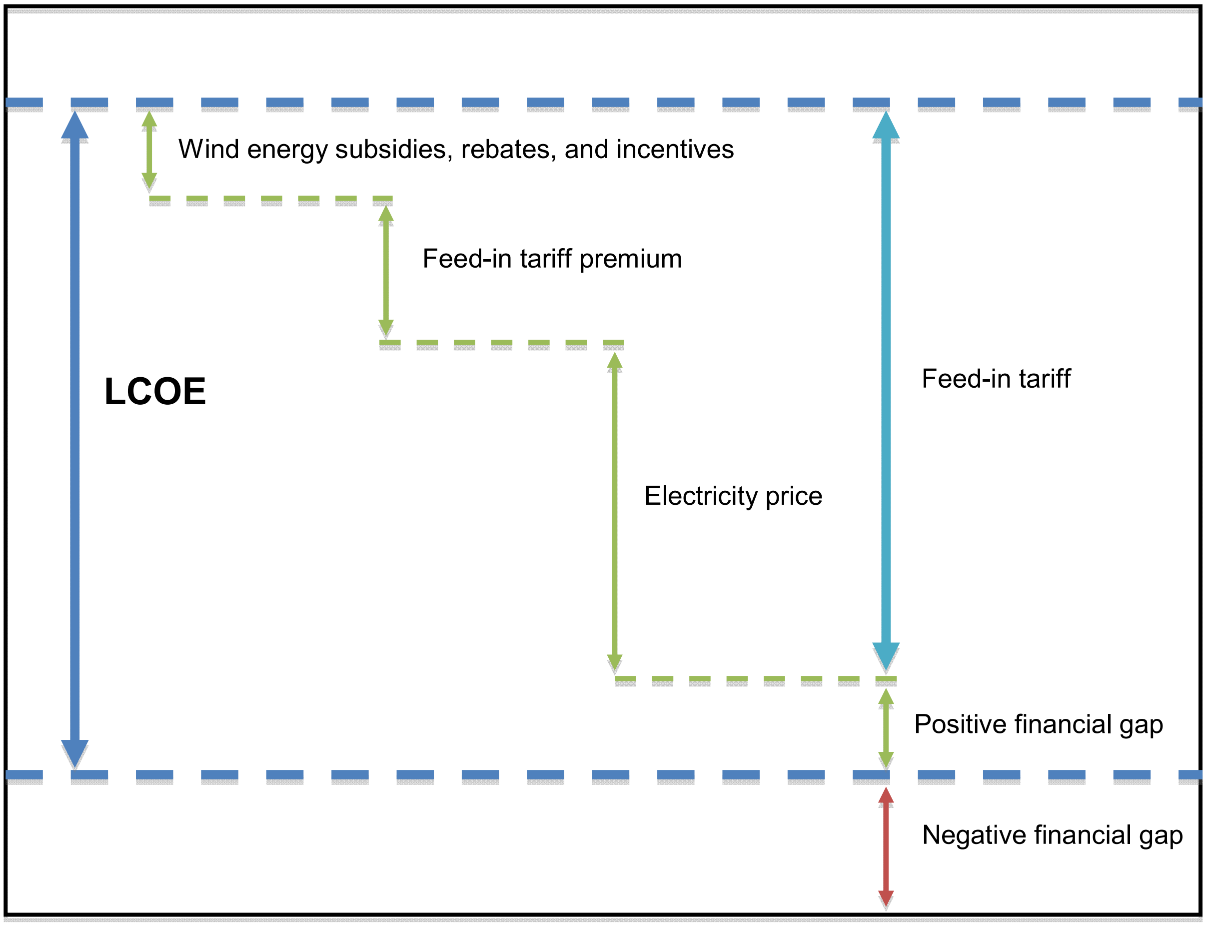

Figure 1-2. The cost of energy offset by revenues and incentives leaving only the financial gap

Cost of Onshore Wind Energy in Participating Countries

The following section presents the country-specific financial cost of onshore wind energy for a domestic investor financing their project in each of the seven participating countries. This uses the ECN model and methodology. Cross-country comparisons of key onshore wind energy cost variables identify differences among each of the countries and offer a baseline onshore wind energy project cost. Due to limited available data, the cost of offshore wind energy is not presented in detail; however, a small sample of reported cost data is included.

Limitations of Reported Data

It is critical to note that, within this analysis, extensive efforts were made to verify the accuracy and validity of all collected wind energy costs, performance, and financial data. However, due to the numerous and diverse sources of data, the quality of the reported data varies among countries and sources. For example, reported cost data are intended to be presented in €2008, though in some instances, it is unclear whether they are presented in current or constant prices. Similarly, the parameters listed below are intended to be reflective of a wind project constructed in 2008; however, it is likely that some of the components were in fact ordered and paid for prior to 2008. Data limitations prevented correction of this possible discrepancy. Furthermore, while IEA Task 26 aims to represent a "typical" project from each country, the actual cost of wind energy is site and project specific. Therefore, the following data are presented as illustrative of overall country-specific conditions only and should be considered with this in mind.

Country-Specific Model Assumptions, LCOE, and the Reference Case

The country-specific costs of wind energy are compared against a baseline project, herein referred to as the "Reference Case". The Reference Case represents a composite of wind energy cost elements from each country. The cost elements in the Reference Case include both technical parameters (e.g., project features, performance, investment outlays, and decommissioning costs, operations and maintenance costs, and others), as well as, financial parameters (e.g., debt and equity shares, return on equity, debt interest rate, loan length, and national tax rate). The Reference Case does not include any revenue or wind energy policies or incentives due to each country's unique approach in supporting wind energy. As such, only the LCOE calculation is presented for the Reference Case.

The country-specific technical parameters are shown in Table 1-2.[4] For each technical parameter, the Reference Case value is calculated as the project-capacity weighted average across all countries. The technical parameter's Reference Case values also are shown in Table 1-2, and are heavily weighted towards Sweden and the United States due to their relatively large project capacities (98 and 85 MW respectively) in 2008. The Reference Case is weighted with project-capacity, instead of total domestic wind energy capacity, to illustrate a more or less typical project experienced in 2008 among each of the seven countries. While there are many differing options to construct the Reference Case project, it is important to point out that the choice of the Reference Case does not impact the country-specific LCOE or FG calculations. Simply, the Reference Case provides a general point for 2008 comparisons to present the country-specific results.

[4] Note that the inputs for the modeling assumptions in Table 3 are shown in euros only; however, the LCOE and FG results are presented in both euros and U.S. dollars.

Table 1-2. Onshore technical parameters by country and the Reference Case in 2008

	Denmark	Germany	Netherlands	Spain	Sweden	Switzerland	United States	Reference Case
Unit size (MW)[5]	2.3	2.0	3.0	2.0	2.4	2.0	1.7	2.1
Number of turbines	7	5	5	15	41	6	50	34
Full load hours	2,695	2,260	2,200	2,150	2,600	1,750	3,066	2,628
Investment[6] (€/kW)	1,250	1,373	1,325	1,250	1,591	1,790	1,377	1,449
Decommissioning costs (€/kW)	0.0	1.5	0.0	0.0	1.6	0.0	0.0	0.6
Other costs (€/MWh)	3	0	10	3	0	0	0	1
O&M costs fixed (€/kW-yr)	0.00	46.33	31.39	0.00	0.01	0.00	8.60	6.29
O&M costs variable (€/MWh)	12	0	13	20	11	31	5	11
Converted total O&M costs (€/MWh)	12	21	28	20	11	31	7	13
Reference Case Weight	6.1%	3.8%	5.7%	11.4%	36.6%	4.6%	31.8%	N/A

The country-specific financial parameters are shown in Table 1-3. For each financial parameter, the median value across all countries is used as the Reference Case value. As noted previously, the calculation of the Reference Case does not impact the country-specific LCOE or FG results.

Although the ECN model uses the return on equity as the discount rate, the weighted average cost of capital (WACC) is also shown in Table 1-3 for illustrative purposes. The WACC incorporates several individual financial parameters (debt to equity ratio, return on equity, debt interest rate, and national tax rate) into a single metric descriptive of overall financing costs.

[5] A more detailed cost of wind energy analysis also would include explicit assumptions pertaining to energy capture components, including rotor diameter, hub height, average wind speed and other significant parameters. The estimates included here are intended to be reflective of high level, simple specifications only, in part, to facilitate comparisons with other technologies and countries not represented here.

[6] As previously noted, the investment outlays and project construction are assumed to have occurred in 2008; however, it is likely that some of the investment outlays (e.g., ordering of the turbine) were in fact made prior to 2008.

Table 1-3. Onshore financial parameters by country and the Reference Case in 2008

	Denmark	Germany	Netherlands	Spain	Sweden	Switzerland	United States	Reference Case
Return on debt (%)	5.0	5.5	5.0	7.0	5.0	5.0	6.0	5.0
Return on equity (%)	11.0	9.5	15.0	10.0	12.0	7.0	7.5	10.0
Debt share (%)	80	70	80	80	87	70	0	80
Equity share (%)	20	30	20	20	13	30	100	20
Loan duration (yrs)	13	13	15	15	20	20	15	15
National tax rate (%)	25.0	29.8	25.5	30.0	28.0	21.0	38.9	28.0
WACC (%)	5.2	5.6	6.0	5.9	4.7	4.9	7.5	4.9

The country-specific LCOE and FG results are shown in Table 1-4 for each country and the Reference Case. The results include the 2008 levelized cost of energy and the financial gap calculation. While the results are intended to be illustrative of overall costs for onshore wind energy by country, the actual LCOEs for any wind project are site and project-specific.

Table 1-4. 2008 Onshore LCOE and FG by country and the Reference Case

LCOE €/MWh ($/MWh)		Financial Gap €/MWh ($/MWh)	
Switzerland	120(167)	Germany	5 (7)
Netherlands	94 (131)	United States	-1(-1)
Germany	85 (118)	Switzerland	-1(-1)
Spain	83 (115)	Netherlands	-3(-4)
Sweden	67(93)	Spain	-3(-4)
United States	65(91)	Denmark	-6(-8)
Denmark	61 (85)	Sweden	-8(-11)
Reference Case	(68)95	Reference Case	N/A

As presented in Table 1-4, the LCOE by country ranges from €120/MWh ($167/MWh)[7] in Switzerland to €61/MWh ($85/MWh) in Denmark. The Reference Case LCOE is estimated at €68/MWh ($95/MWh). The primary reasons for the variations of LCOEs across countries are due to differences in country-specific energy production, O&M expenditures, investment costs, and financing. The impact of these parameters on the country-specific LCOE is explored in the following section.

Cross-Country LCOE Comparisons

The cross-country analysis examined the LCOE impact of four key cost parameters between countries. For each country, the LCOE was estimated, with a single cost parameter set at a country-specific value, while all other parameters were set to the Reference Case value. The analysis isolated the impact of the country-specific input parameter compared to the baseline metric (the Reference Case parameter value). The key parameters tested in the cross-country

[7] Exchange rate of 1.39 USD/EUR is used in currency conversions.

analysis included energy production, investment costs, operations and maintenance costs, and financing costs. The results were then compared across all countries.

For example, the LCOE impact, of each country's unique full load hours, is shown in Figure 1-3, which compares three distinct test cases. First, the grey bars show the unique country LCOE previously presented in Table 1-4, in which all input parameters are set to their country-specific values. Second, the blue line shows the baseline Reference Case LCOE at €68/MWh, in which all parameters are set to the Reference Case values. Third, the green circular markers show a mixed case, in which full load hours are set to the country-specific value while all other parameters are set to the Reference Case values.

Figures 1-3 though 1-6 present this analysis of energy production (described above), investments costs, operations and maintenance costs, and financing costs, respectively. The country-specific LCOE (grey bars) and the Reference Case LCOE (blue line) are constant in each of the figures, while the key cost parameter is unique to each figure and is shown with distinct markers.

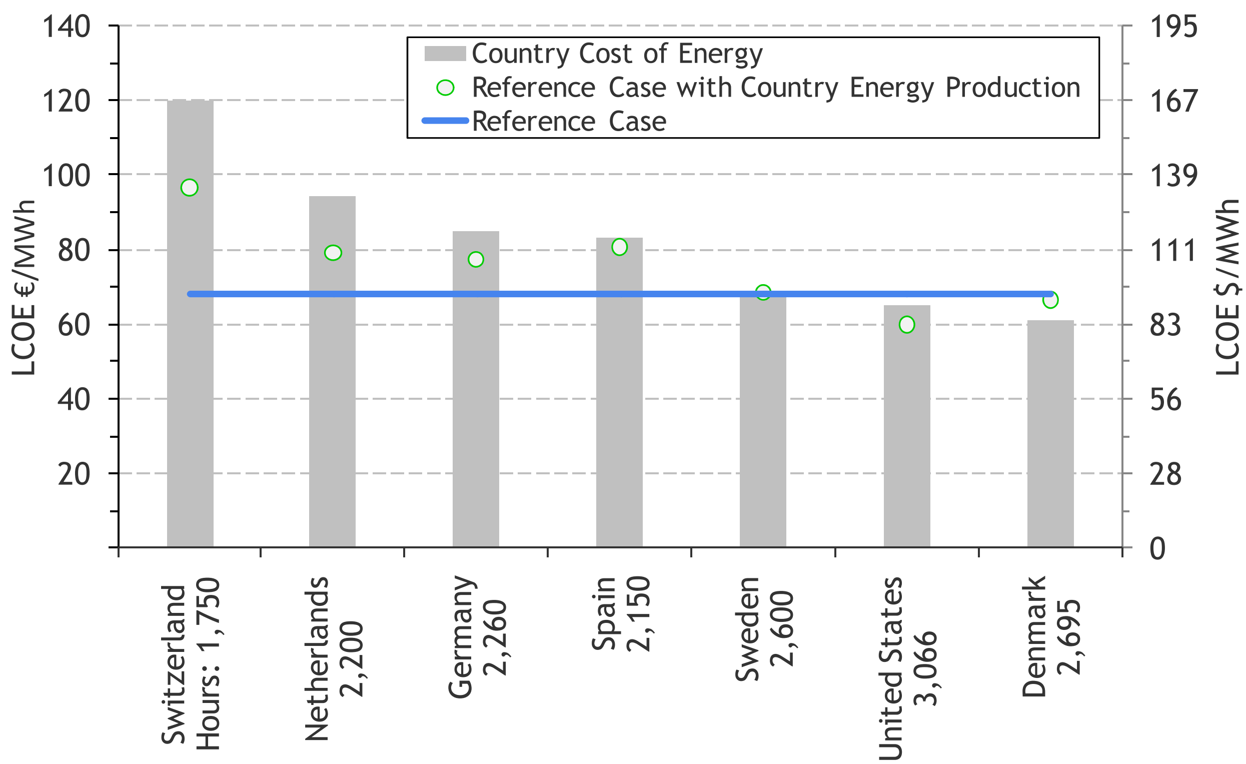

Figure 1-3. Impact of country-specific energy production on the Reference Case

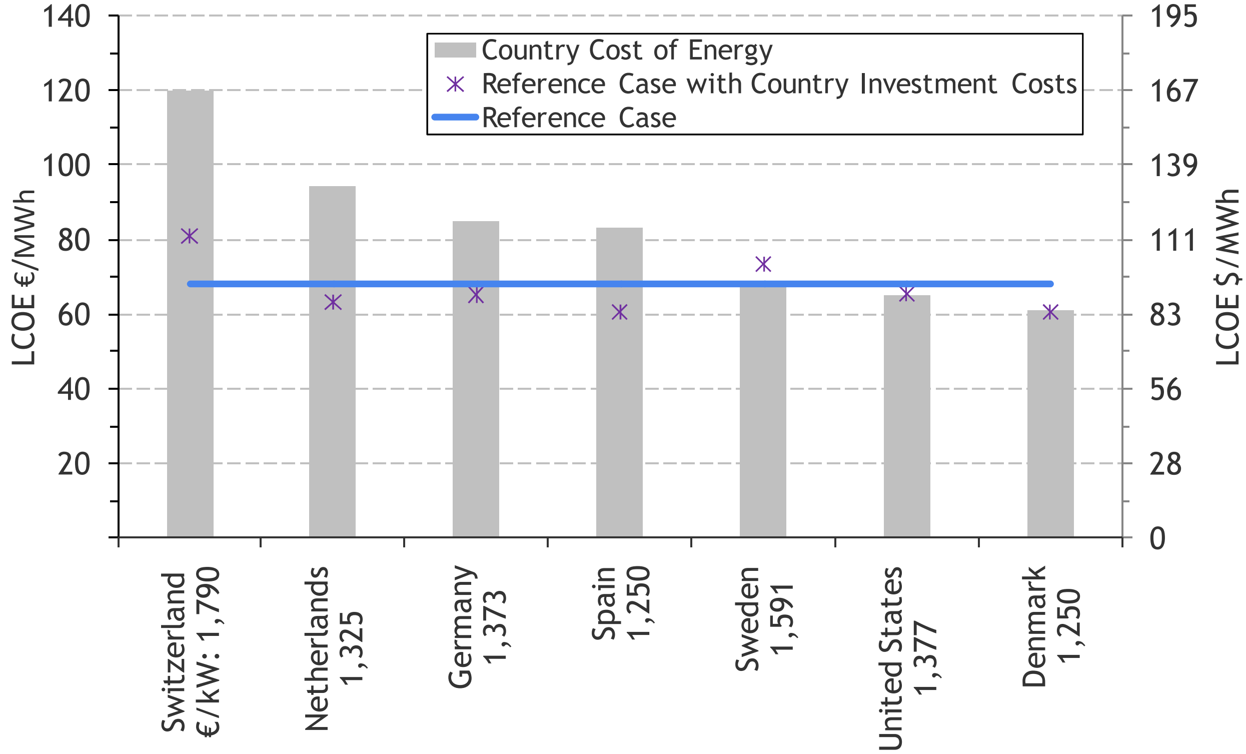

Figure 1-4. Impact of country-specific investment costs on the Reference Case

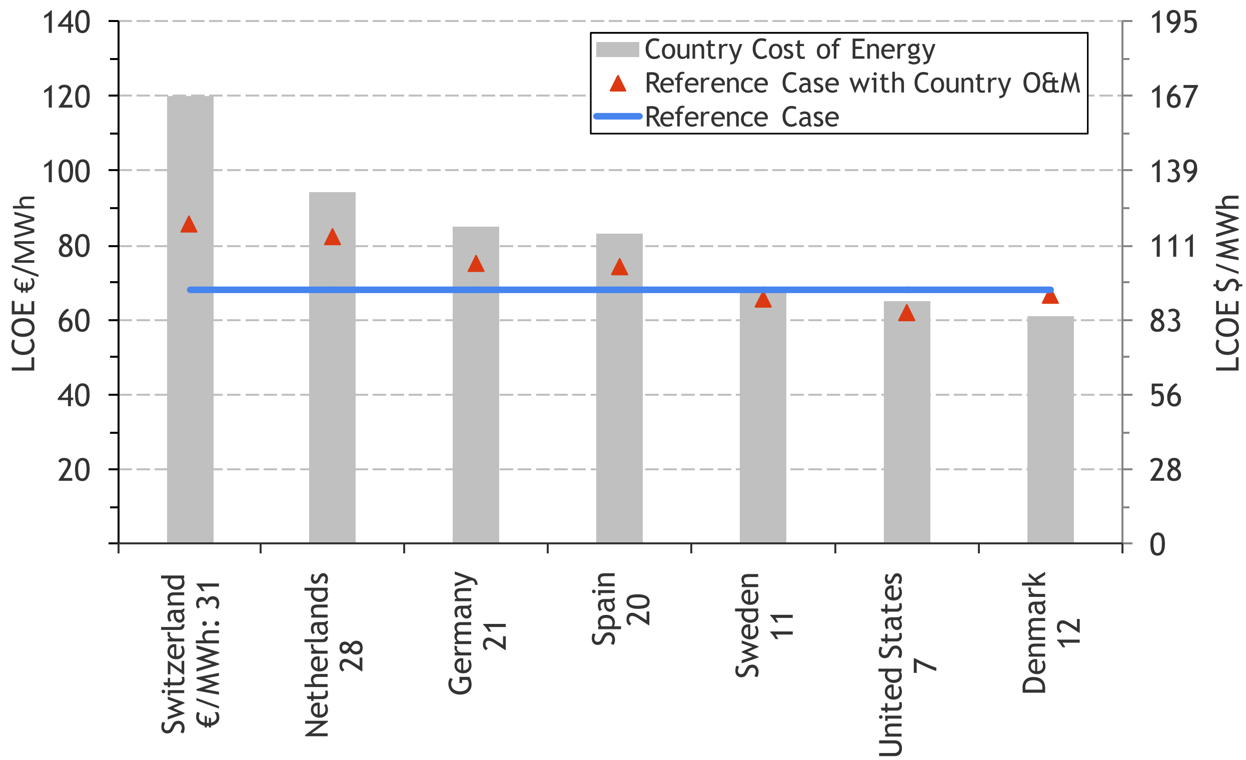

Figure 1-5. Impact of country-specific O&M costs on the Reference Case

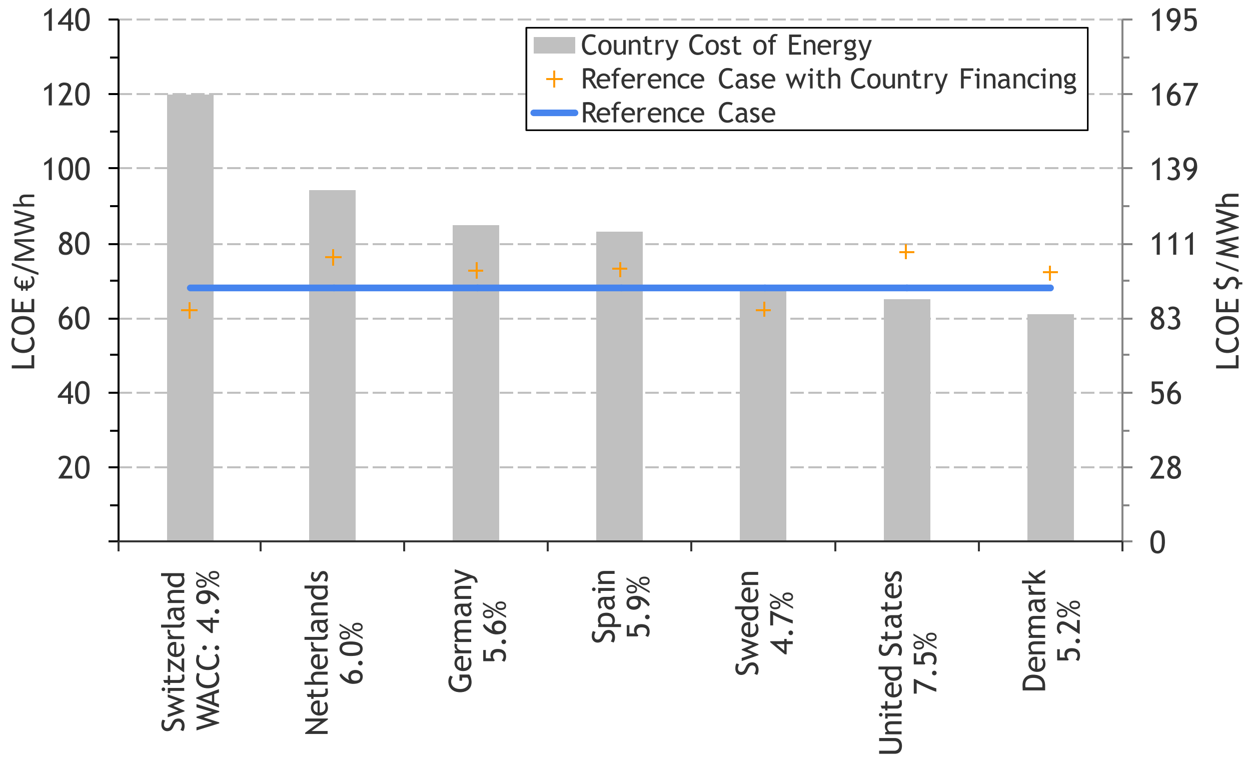

Figure 1-6. Impact of country-specific financing costs on the Reference Case

Some explanations for the variation in the key wind energy cost parameters across countries include, but are not limited to, the following:

- **Energy Production (Full Load Hours):** The variation of full load hours across countries is due to a number of common and independent factors. For example, in Germany, land constraints have pushed project development to southerly sites with poorer wind resources. In Denmark, spatial planning may promote repowering of existing wind sites ahead of expansion of undeveloped sites within the country. Consequently, some of the premier wind resource sites in Denmark were targeted in 2008 for repowering. In Switzerland, limited mountain accessibility has led to the development of just a few projects through 2008. In the United States, there are numerous project sites with sufficient to excellent wind resources; however, limited transmission access and availability have influenced project location decisions and, in some cases, forced the curtailment of energy output. Similarly, land constraints in Sweden are less of an issue than in other countries in the study. In the Netherlands, a feed-in-tariff premium, which is capped at a maximum amount of full load hours, may reduce the financial incentive to develop premier sites or utilize the most sophisticated technology.
- **Investment Costs:** Investment costs range significantly across countries. In both Denmark and the Netherlands, a feed-in tariff premium subsidy based on full load hours influences the choice of the wind turbine and, therefore, a project's investment costs. In Denmark, preference may be given to turbines with large generators to maximize the value of the subsidy per full load hour, while in the Netherlands preference may given to less expensive

turbine technology since the subsidy is capped at maximum full load hours. In Denmark, some costs of installing a wind project, such as those interconnecting to the electric grid, are paid by the project's end users (ratepayers) as opposed to the project's developers. As such, interconnection costs are not included in Denmark's investment costs. However, in Spain, Germany, and several other countries, interconnection costs and other grid reinforcement costs are paid for by the project developer and are included in investment costs. In Sweden, there is a simplified procedure for grid interconnection that may offer some investment cost savings. Germany's expansion of wind projects to southerly sites, with poorer wind resources, caused developers to compensate by constructing many of those projects at higher hub heights using larger rotor diameters (both of which are significant investment cost contributors). In Switzerland, difficulty accessing mountainous wind project sites, and the lack of economies of scale, have also contributed to high investment costs.

In the United States, the cost-benefit of large project sizes is particularly applicable to the purchase of turbines, and there is evidence of price discounts as order size increases. The larger wind farm project sizes and less expensive investment costs in the United States, when compared to the Reference Case, suggest that the United States developers benefit from quantity discounts. Interestingly, Sweden does not benefit from a price reduction corresponding to large project size. This could be attributed to a smaller amount of total domestic installations in 2008 compared to the modeled project capacity.

- **Operations and Maintenance Costs:** Operations and maintenance cost data for each country were indicated as either highly uncertain or not readily available**.** In Denmark, creditors of wind projects typically require long-term O&M service contracts for 5-10 years. These were reported to cost approximately €25/kW annually. The Netherlands reported that their O&M costs typically also include a service contract that is priced consistently across projects, and a land-rent component, with a cost that varies significantly across projects, reportedly from €5/kW to €23/kW. Full service contracts often are required for a minimum of five years in Germany, as well. In Switzerland, limited O&M experience, high labor costs, accessibility difficulties, and turbine icing or turbulence may have led to higher O&M expenditures than in other countries. In the United States, O&M costs, on average, appear to be lower for projects installed more recently, and for larger project sizes. However, anecdotal evidence suggests that U.S. O&M cost estimates, including premature component replacements of gearboxes, blades, or generators, may be under-represented in the reported data. Germany also reported increased O&M expenditures for smaller projects due to the necessity of stocking replacement components. Moreover, Germany reported costly periodic site inspections as an important component of overall O&M costs. In Sweden, the spread of operations and maintenance costs varies widely by project developer.
- **Financing Costs:** The financing costs of onshore wind projects are similar across countries, with the exception of the United States. In Denmark, Germany, and the Netherlands, wind projects are typically project-financed, unless they are developed by a utility that finances wind projects on their balance sheets. In Denmark and Sweden, onshore wind projects are generally viewed as a low risk venture and finance pricing for onshore projects reflects this. In every country, except the United States, high debt ratios are utilized to finance a project, typically ranging from 60% to 87%.

The United States is a relative anomaly in the financing of wind projects. In 2008, many projects in the United States were financed with very high equity percentages (often 100%) and little to no project-based debt. This was due to federal tax subsidies that led to the proliferation of a specialized form of equity financing, known as tax equity. Because of the preference for tax equity financing, the cost of capital was generally higher in the United States than in other countries (i.e., tax equity is typically more expensive than debt). In instances in which debt financing was used to finance a project in the United States, the debt was often secured at the corporate-level instead of at the project-level.

In summary, Figure 1-7 shows a composite of the four key cost elements shown in Figure 1-3 through 1-6, as well as, the country-specific LCOE and the Reference Case LCOE.

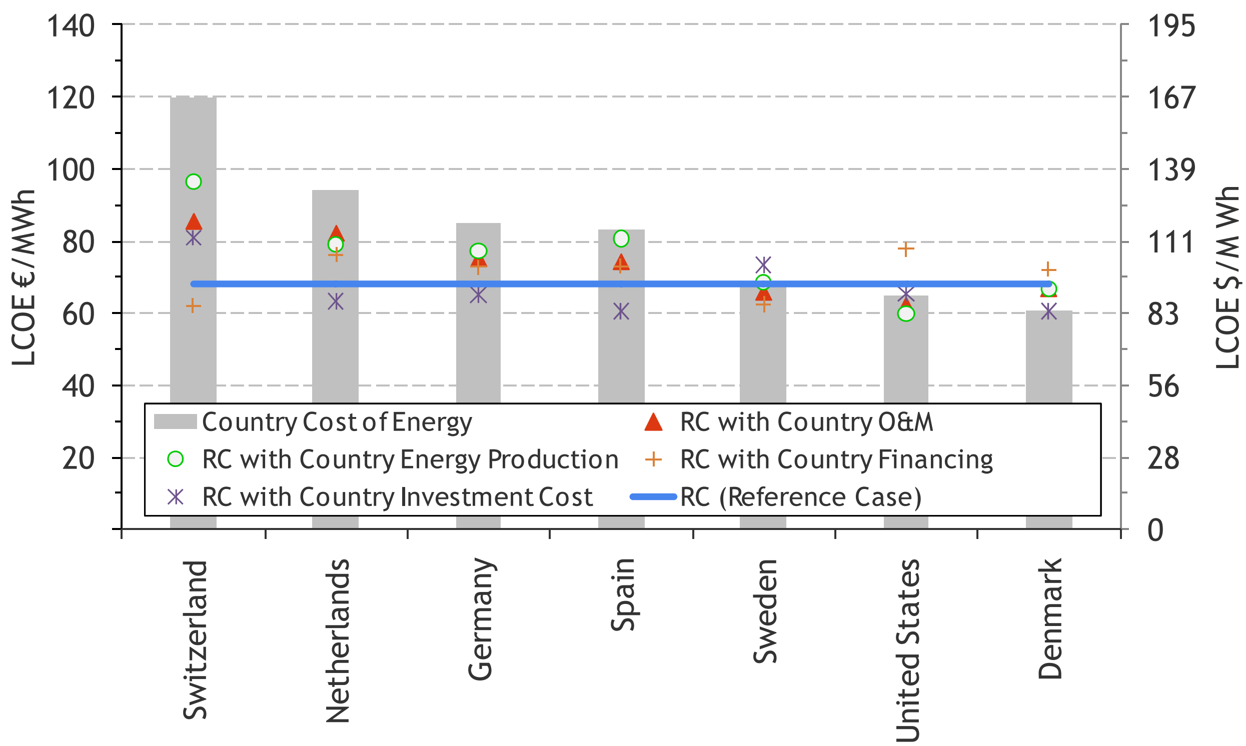

Figure 1-7. Composite of country-specific costs on the Reference Case

To further illustrate the LCOE impact of key cost variables relative to other variables, Figure 1-8 groups key cost parameters together, instead of delineating them by country. Figure 1-8 shows the impact of each country-specific cost variable, and the magnitude of increase or decrease in the country's LCOE, when compared to the Reference Case. Red bars indicate country-specific values that increase the country's LCOE, while green bars show country-specific values that decrease the country's LCOE from the Reference Case. From top to bottom, the key cost parameters are listed by the magnitude of the LCOE increase above the Reference Case (red bars). For example, the smallest energy production variable, reported by Switzerland, increased the country's LCOE by a greater amount than its O&M and investment costs.

When considering the spread, of country-specific input parameters, from lowest to highest, energy production and investment costs resulted in the largest LCOE impacts. This is generally consistent with previous wind LCOE sensitivity analyses (IEA 2010, Cory and Schwabe 2009). Interestingly, however, the range of reported O&M expenditures increased the LCOE estimates by a larger amount than the highest cost investment or financing expenditures, when comparing the Reference Case value to the highest-cost value. This could suggest that the uncertainty and availability of O&M data, and thus the wide range of country-specific input parameters, limits the precision of the LCOE estimate. Future analysis to reduce the differentials due to O&M expenditures may be needed.

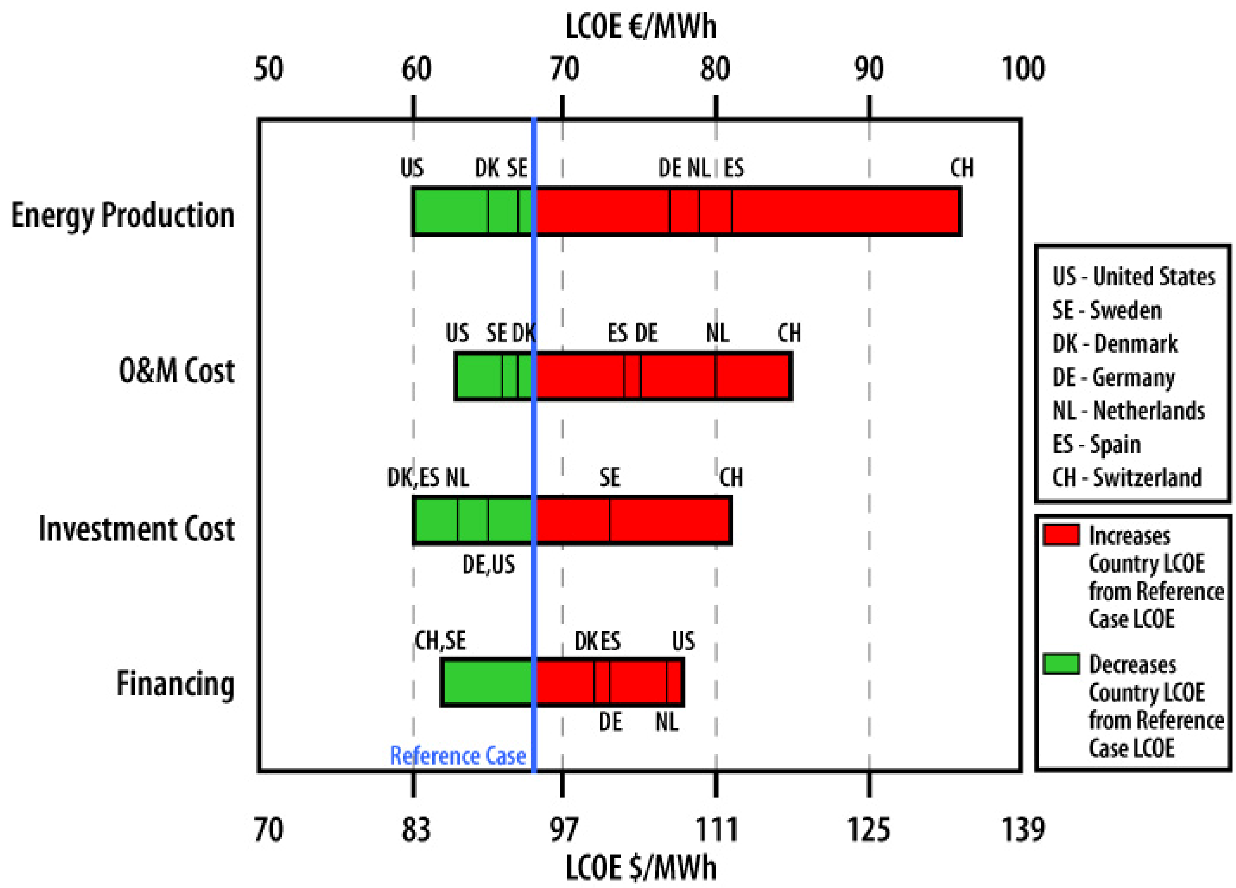

Figure 1-8. Key cost parameter's LCOE impact across countries

Cost of Offshore Wind Energy in Participating Countries

In addition to onshore wind, the ECN model can estimate LCOE for offshore wind installations. At this time, however, very limited offshore data is available; particularly the full suite of input variables that are necessary to estimate country-specific LCOE. As such, cross-country LCOE comparisons for offshore wind are not made, nor is an offshore Reference Case constructed. Some reported cost and financing data are presented in Tables 1-5 and 1-6 below. It is important to note that, in Denmark, connecting to the grid and the necessity of a sea cable are socialized costs and, therefore, not borne by the project developer. Because the model used in this analysis is from the perspective of the project developer, these costs are not captured in the Danish investment cost estimate. Although not used in the modeling analysis, the inclusion of these grid connection costs would increase the Danish investment cost estimate to approximately €3,000/kW. Table 1-7 shows the LCOE and financial gap estimated for these offshore wind energy projects.

Table 1-5. Offshore technical parameters by project

	2007 Netherlands Prinses Amalia	2008 Denmark Rødsand II	2008 Germany Generic
Project Status	2007 Cost Projection	2008 Cost Projection	2008 Cost Projection
Year of completion	2007	Late 2010	Not Specified
Unit size (MW)	2.0	2.3	5.0
Number of turbines	60	90	12
Full load hours	3,350	3,800	3,700
Investment (€/kW)	3,315	1,883	3,230
Decommissioning costs (€/kW)	0	0	0
Other costs (€/MWh)	11	0	0
O&M costs fixed (€/kW)	149	0	123
O&M costs variable (€/MWh)	0	24	0
Converted Total O&M costs (€/MWh)	44	24	33
Economic life	15	25	20

Table 1-6. Offshore financial parameters by project

	2007 Netherlands Prinses Amalia	2008 Denmark RØdsand II	2008 Germany Generic
Return on debt (%)	5.0	4.5	6.5
Return on equity (%)	12.0	11.2	15.0
Debt share (%)	50	26	70
Equity share (%)	50	74	30
Loan duration (yrs)	15	13	12
National tax rate (%)	25.5	25.0	29.8
WACC (%)	7.9	9.2	7.7

Table 1-7. Offshore LCOE and FG by project

LCOE €/MWh ($/MWh)		Financial Gap €/MWh ($/MWh)	
Prinses Amalia	166 (231)	German Generic Projection	N/A
German Generic Projection	156 (217)	RØdsand II Projection	6(8)
RØdsand II Projection	88 (122)	Prinses Amalia	5(7)

Other Approaches to LCOE Calculation

LCOE is calculated for a variety of purposes, motivations, and audiences. The general public, policymakers, investors, project developers, and others use LCOE for their particular needs. Therefore, each may utilize a different methodological approach. The level of detail, or the necessary assumptions, to estimate LCOE varies among methods and can have a significant impact on the LCOE outcome. Therefore, an alternative approach to calculating levelized cost of energy is described below, in contrast to the ECN model and methodology used thus far in the analysis.

For example, high-level planning scenarios often estimate levelized cost of energy using a simplified representation that is based on the present values of the investment cost and the average annual costs discounted using a social discount rate. Under this approach, assumptions for explicit financing terms, such as debt to equity ratios, costs of debt and equity, loan duration, and corporate taxes, are not made. Instead, the simple approach relies on the value chosen for the discount rate, and this represents all of the characteristics of the finance instrument. The IEA "Projected Costs of Generation Electricity" (IEA 2010) and the "IEA World Energy Outlook 2009" (IEA 2009) adopt this approach, and use the following equation to calculate the levelized cost of electricity:

$$\boldsymbol{LCOE} = \frac{\sum_t((Investment_t + O\&M_t + Fuel_t + Carbon_t + Decommissioning_t) * (1 + Discount\ Rate)^{-t})}{(\sum_t(Electricity_t * (1 + Discount\ Rate)^{-t}))}$$

Under this approach, IEA describes the discount rate as the "social resource cost," which reflects the cost that society, as a whole, has to bear when investing in a specific technology (IEA 2010) From this social perspective, IEA uses a discount rate range from 5% to 10%, with 5% representing "a rate available to an investor with a low risk of default in a fairly stable environment" and 10% representing "the investment cost of an investor facing substantially greater financial, technological, and price risks" (IEA 2010). The more simplistic, high-level planning scenario minimizes the number of input parameters, and the level of detail facilitates LCOE comparisons among many different electric generation types.

Conversely, sophisticated cash flow models, like the ECN model, are used by developers to evaluate specific projects, their LCOE, and a number of other financial metrics, such as net present value, internal rate of return, or payback period. These models often include several owners, a suite of explicit financing assumptions, tax impacts, and other revenue or cost influences. They are often structured to evaluate all likely cost streams and to solve for an energy price that provides a return large enough for a company to invest in a particular project

(Harper et al. 2007). Under this more detailed methodology, LCOE is impacted by numerous influences beyond the investment or annual costs. As the ultimate decision to build a project often rests with the investor, it is important to understand the investor perspective to understand the cost threshold that will allow wind capacity installations to continue.

As an example, the ECN model used in this analysis is a sophisticated cash flow model that estimates a project-specific LCOE, while ensuring a pre-defined return on equity (ROE) to the equity investor. As described earlier, the additional detail in the ECN cash flow model allows the explicit representation of financing structures that have debt and equity interests. Representation of the cost of wind energy, from the perspective of the project developer, provides an estimate of the cost of wind generation that must be offset with income streams for a project to proceed.

Comparison of Discount Rates on LCOE Calculation

Table 1-8 shows a discount rate and LCOE methodology comparison. Using both the simple and the sophisticated cash flow analysis methods, the LCOE is estimated over a range of discount rates, while all other costs parameters were set to their Reference Case values. In addition, the discount rate value that yields the Reference Case LCOE (€68/MWh) is presented under both methods.

The typical discount rate values selected to represent the perspective of the social investor tend to be lower than the corresponding values representing the private project developer or investor perspective. According to IEA 2010, the reason for using the lower discount rate in the social perspective is that public investors typically face lower financing costs and risks because the risk is spread over a large number of individuals instead of a smaller number of private investors. Correspondingly, the social perspective LCOE estimates also tend to be lower than the estimates for the private developer.

Table 1-8. Comparison of discount rate values and LCOE methodologies

Methodology & Perspective	Perspective	Treatment of Financing	Application	Discount Rate Range	LCOE at Discount Rate Range*	Discount Rate That Yields Reference Case LCOE
Simple calculation for high-level scenario planning	Public/Social investor perspective	Implicit in discount rate	IEA 2010	5% – 10%	53 – 70 €/MWh (IEA Method)	9.5% (IEA Method)
Sophisticated cash flow analysis	Project developer or private investor	Explicitly defined	ECN 2008	7.5% – 15% (ROE)**	64 – 76 €/MWh (ECN Method)	10% (ECN Method)

*Using Reference Case assumptions for all other variables
**Based on range of range of reported ROE's from this analysis.

As shown in Table 1-8, under both approaches, the difference in the selection of the discount rate impacts the LCOE value significantly. A discount rate of 9.5% is necessary to calculate the Reference Case LCOE of €68/MWh, using the simple calculation representing the social perspective. Therefore, based on the reported data by countries in this study, the discount rate should near the high end, 5-10% of values suggested in the IEA range of the simplified social planning method, to approximate the sophisticated cash flow approach.

Conversely, the use of a lower discount rate (the low end of the suggested range) is used to represent the case of public investors. Therefore, when calculating the LCOE, and also when comparing the LCOE of wind energy to that of other generation sources, it is imperative that either the project developer perspective, or a broader utility or system-level perspective, is clearly identified. The selection of the discount rate value should correspond to the represented perspective. Utilization of various equations to represent LCOE requires clear interpretation of the perspective represented, the discount rate, and other parameter values chosen.

Conclusions

Results of IEA Wind Task 26 indicate that the LCOE varies considerably between countries. The magnitude of this variation has been attributed to energy production, investment cost, operations cost, and financing cost. As expected, the largest LCOE impacts, from country to country, were the anticipated energy production based on the inherent wind regime or wind turbine technology specifications. Market forces greatly impacted the overall cost of wind energy through large variations in both capital expenditures and differences in financing terms for a wind project. Costs attributed to the operation of a wind project ranged widely across countries and had a sizable LCOE impact.

The nature of LCOE, as a single overall metric descriptive of the cost of energy, allows for seemingly simple comparisons to be made across countries, purposes, audiences, and other uses. However, the various methods of calculating LCOE require careful attention to precisely how, and from what perspective, the calculation is made. LCOE is not a universal, interchangeable calculation. Rather, LCOE is an informative and useful tool that can be adapted to a particular need. Therefore, comparisons should be made and interpreted carefully.

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Chapter 2: Denmark

Overview of Wind Industry in Denmark

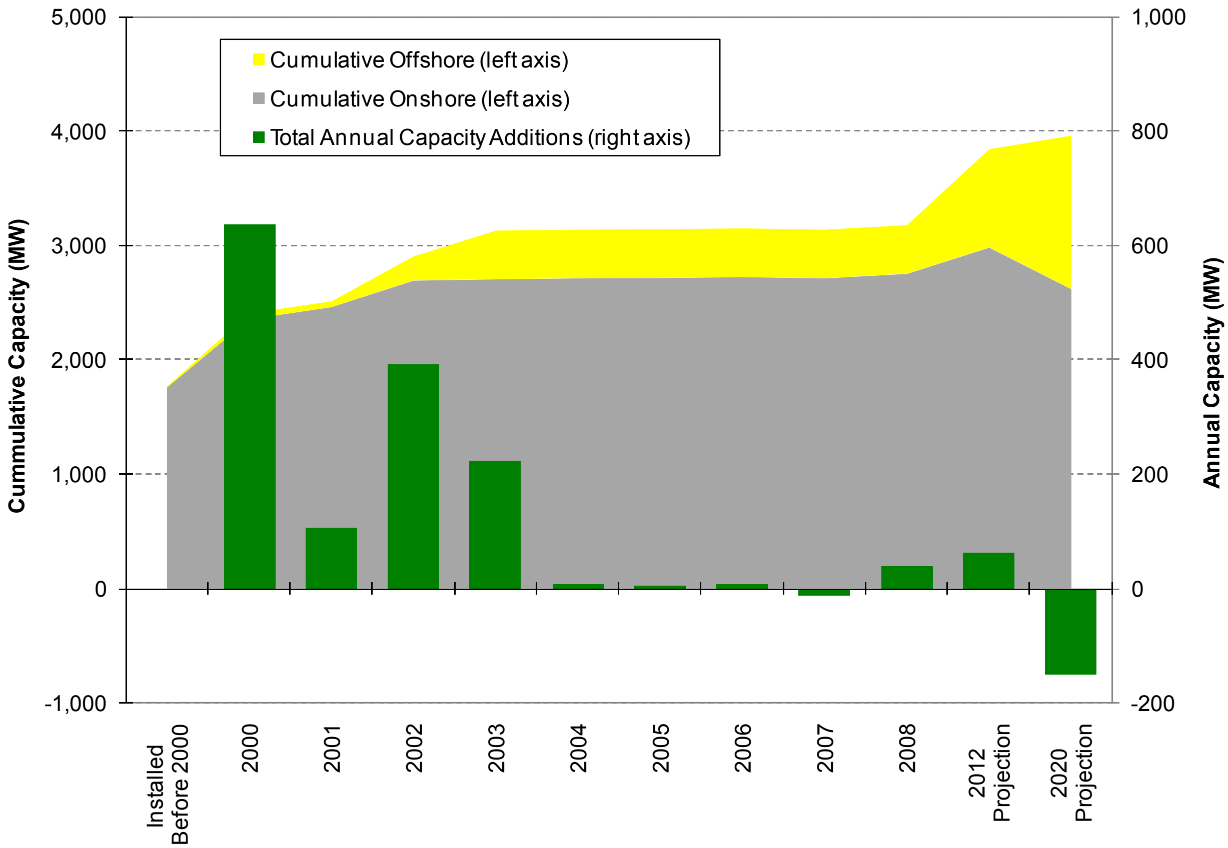
The following chapter describes the project and cost characteristics of onshore and offshore wind energy in Denmark. It focuses on the assumptions used in modeling the levelized cost of energy (LCOE) for onshore and offshore wind technologies in 2008.

Capacity, Energy Production, Near-Term Targets

Total installed wind capacity in Denmark at the end of 2008 was 3,179 MW (2,756 MW onshore and 423 MW offshore). This is an increase of approximately 1.25% compared to the installed capacity at the end of 2007, and a 32% increase compared to the installed capacity in 2000. Approximately half of the increase in installed capacity from 2001 to 2008 occurred offshore. Three offshore wind farms were under construction in 2008, two were completed in 2009, and the third was expected to be commissioned in the fall of 2010.

As shown in Figure 2-1 below, the rate of deployment was not evenly distributed throughout the period. A net increase of 725 MW of installed capacity was achieved from 2001 to 2003, while installed capacity only increased by 8 MW from 2004 to 2007. This was a result of a dramatic reduction in the financial support program for onshore deployment that took effect in 2003. A new feed-in tariff supplement introduced in 2008 resulted in renewed interest in erecting onshore turbines. Since its introduction in 2008, a net increase of 280 MW of onshore capacity was achieved by the end of July 2010 (Danish Wind Industry Association, 2010).

In 2008, wind power production in Denmark supplied approximately 20% of the total electricity consumption.



Source: Danish Wind Industry Association 2010 and European Commission 2010

Figure 2-1. Cumulative and annual Denmark wind installations

Denmark does not have annual targets for wind power deployment. EU requirements have, however, necessitated that Denmark produce a plan for achieving a target of 30% of total energy consumption, including the transportation sector, from renewable sources by 2020. EU regulations require that each member state produce an action plan for achieving the RE target. Denmark published its national action plan in June 2010. The plan estimates that wind power production in 2020 will be 11,000 GWh from approximately 4 GW of installed capacity. One third of total capacity, and approximately 50% of production, is expected to be from offshore turbines (Kemin 2010). Production in 2009 was approximately 6,700 GWh. The wind energy capacity projections in 2012 and 2020 are from the National Renewable Energy Action Plans (NREAP) of the European Member States (European Commission 2010).

Short term goals include adding 800 MW of offshore capacity between 2008 and 2012, and 350 MW of new onshore capacity. Half of the target must be achieved through repowering, which will result in a cumulative increase of 175 MW. Local planning authorities must have planning provisions in place to add 150 MW of onshore capacity, above the 350 MW, by 2012.

The short term target of 800 MW for offshore wind is expected to be achieved through the commissioning of three large offshore wind farms; Horns Rev II (209 MW, commissioned in September 2009), Rødsand II (207 MW, planned for autumn 2010) and Anholt (400 MW, planned for December 2012).

Table 2-1 presents historical and projected *cumulative* wind energy installed in Denmark

Table 2-1. Cumulative wind energy installations in Denmark (MW)

	Installed Before 2000	2000	2001	2002	2003	2004	2005	2006	2007	2008	Projection 2012	Projection 2020
Onshore	1,761	2,358	2,464	2,697	2,708	2,716	2,720	2,728	2,717	2,756	2,985	2,621
Offshore	11	50	50	210	423	423	423	423	423	423	856	1,339

Source: Danish Wind Industry Association 2010 and European Commission 2010

Table 2-2 shows historical and projected *annual* capacity additions.

Table 2-2. Annual wind energy installations in Denmark (MW)

	Installed Before 2000	2000	2001	2002	2003	2004	2005	2006	2007	2008	Projection 2012	Projection 2020
Onshore	1,761	597	106	183	12	8	4	8	-11	39	-38	-135
Offshore	11	39	0	210	223	0	0	0	0	0	100	-14

Source: Danish Wind Industry Association 2010 and European Commission 2010

Revenue and Policy Incentives

The renewable energy law of 2008 introduced a new remuneration system for wind power projects. All new onshore wind power projects and open door offshore projects[8] receive a price supplement of DKK 0.25/kWh (€0.034/kWh[9]) ($0.047/kWh) over and above the spot market price for the first 22,000 full load hours[10]. Once this is reached, wind power projects receive the market price for power.

Wind turbines receive an additional subsidy of DKK 0.0237/kWh (€0.0037/kWh) ($0.005/kWh) for the technical lifetime of the project to cover balancing costs.

It generally takes between 7 and 10 years for a wind turbine to produce the equivalent of 22,000 full load hours in Denmark.

If, for example, a 3 MW turbine is erected, the feed-in tariff is determined as follows:[11]

$$\text{1 full load hour for a 3 MW turbine} = 3{,}000\ \text{kWh}$$

$$3{,}000\ kWh \times 22{,}000 = 66\ GWh$$

The feed-in tariff and the balancing subsidy are paid for the first 66 GWh of production for a 3 MW turbine.

8 Open door projects are defined as offshore projects built outside of the public bidding process for offshore wind power plants. One offshore power plant has been built using the open door application process.
9 1 Euro = 7.353 Danish Krone
10 The current price supplement replaced a program whereby wind projects received DKK 0.10/kWh (€0.013/kWh)
11 The following example is not included in other country chapters, therefore is reported in Danish Kroner.

This has a value of:

$$(66\text{ GWh } \times 0.25\text{kr}) + (66\text{ GWh } \times 0.0237\text{kr}) = \ DKK\ 18{,}064{,}200$$

A repowering subsidy is also available for new wind power projects that decommission older turbines. The subsidy is DKK 0.08/kWh(€0.01/kWh)($0.0139) for 12,000 full load hours for double the decommissioned capacity. If, for example, a 225 kW wind turbine is purchased and decommissioned by a new project development, then the repowering subsidy is calculated as follows:

$$1 \text{ full load hour for a } 225\ kW \times 2 = 450\ kWh$$
$$450\ kWh \times 12{,}000\ = 5.4 \text{ GWh}$$

The repowering subsidy for a decommissioned 225 kW turbine has a value of

$$5.4\ GWh \times 0.08kr = DKK\ 432{,}000$$

This subsidy applies only for decommissioned turbines under 450 kW. There is no limit to the number of turbines a new project can decommission to benefit from the repowering subsidy, but the subsidy is only available for the decommissioning of a total of 175 MW of turbines under 450 kW.

A feed-in tariff based on full load hours, rather than a uniform number of kilowatt hours produced, generally favors investments in turbines with larger generators rather than those with higher hub heights and larger rotors. A 3 MW generator, for example, will produce twice the amount of kilowatt hours per full load hour than a 1.5 MW turbine will produce and therefore, it would receive double the subsidy.

The influence a feed-in tariff has on the choice of turbine for a wind project is illustrated in Tables 2-3 and 2-4 below. The examples are taken from an actual project.

Table 2-3. Relative values of 4 turbine models with varying hub heights, rotor diameters, and generator capacities before feed-in tariff based on full load hours[12]

Generator size, MW	Rotor	Hub Height	Annual production, MWh	Project cost/ turbine, MDKK	Value of power sales, MDKK	Income/ investment	Relative value
3,0	90	80	7,089	22.2	49.6	2.23	0.98
3,0	90	90	7,497	23.43	52.5	2.24	0.99
3,0	112	94	10,384	32.6	72.7	223	0.98
1,8	90	80	6,047	18.6	42.3	227	**1.00**

(Nielsen et al. 2010)

[12] The following example is not included in other country chapters; therefore, it is reported in Danish Kroner.

Table 2-4. Relative values of 4 turbine models with varying hub heights, rotor diameters, and generator capacities including feed-in tariffs based on full load hours

Generator size, MW	Rotor	Hub Height	Annual production, MWh	Project cost/ turbine, MDKK	Value of power sales, MDKK	Value of subsidy, MDKK	Total income, MDKK	Income/ investment	Relative value
3.0	90	80	7,089	22.2	49.6	16.5	66.1	2.98	**1.00**
3.0	90	90	7,497	23.43	52.5	16.5	69.0	2.95	0.99
3.0	112	94	10,384	32.6	72.7	16.5	89.2	2.73	0.92
1.8	90	80	6,047	18.6	42.3	9.9	52.2	2.81	0.94

(Nielsen et al. 2010)

The example above indicates how a feed-in tariff that is based on full load hours favors investments in large generators rather than large rotors and higher towers. In Table 2-3, the most economically efficient turbine is the smaller 1.8 MW, with a large rotor. This also would be the case if the feed-in tariff was based on a uniform number of kilowatt hours produced for all turbines. In Table 2-4, the additional income from the feed-in tariff, based on full load hours, favors the 3 MW generator with the smaller rotor and lower hub height, while the smaller generator is relegated to third.

The advantage of using full load hours as the basis for a feed-in tariff is that it results in fewer turbines being built to achieve a prescribed level of installed capacity. It also reduces the benefits of larger rotors and higher hub heights. These two issues can often be problematic in spatial planning and local acceptance of projects. Feed-in tariffs based on full load hours will favor achieving a political target based on installed capacity deployed, such as the short term target for wind power deployment in Denmark.

The disadvantage of basing the feed-in tariff on full load hours is that the most economically efficient turbines are not necessarily the most attractive for project developers because the subsidy distorts the market. This can ultimately result in wind power being more expensive than it would be otherwise. This form of feed-in tariff used in Denmark ultimately increases the costs associated with achieving production-based targets.

Typical Wind Energy Project in Denmark in 2008

The following section describes 2008 wind power project characteristics in Denmark. The data is based on an average for projects planned or commissioned in 2008. The investment costs for onshore turbines vary according to site conditions, yet production costs in Denmark appear to be relatively uniform. Investment costs per installed MW can vary by up to 50%, while investment costs per MWh of production in the first year generally vary by less than 15%.

Onshore

Project Features

Onshore wind projects in Denmark are generally in the form of small clusters ranging from 3 to 12 turbines. Planning guidelines recommend that wind power projects should be erected in clusters of at least three turbines arranged in a straight line or a gentle curve to avoid the prevalence of single turbines scattered throughout the landscape and reduce visual impact. There are a few examples of larger onshore wind farms in Denmark, but relative to Spain and the United States, they are very small. The largest is 20 turbines with a total capacity of 63 MW.

The average size of turbines installed in 2008 was 1.9 MW, with a rotor diameter of 80m, and a hub height of 72m. The most common turbine installed in 2008 was a 2.3 MW generator, with a hub height of 80m and a rotor diameter of 93m.

Project Performance

The prevailing wind direction in Denmark is westerly, which makes sites along the North Sea coast the most attractive for wind turbines. Even though wind resources generally decline as one moves eastwards, most coastal and near coastal sites have an average annual wind speed above 7 meters per second (m/s). This equates to approximately 2,500 full load hours for a 2 MW turbine, with a hub height of 80m (Danish Energy Agency, 2010). The average number of full load hours in 2009, for turbines installed in 2008, was 2,639. The 2009 wind resource in Denmark was 88% of a normal year, indicating that the lifetime average number of full load hours for turbines installed in 2008 is expected to be approximately 3,000. It is important to note that the estimated full load hours are based on projects installed in 2008 that operated during 2009 – and not on total Danish wind resource potential.

Investment Costs

Typical project investment costs ranged from €1,100/kW ($1,529/kW) to €1,300/kW ($1,807/kW) in 2008 with an average of €1,250/kW ($1,738/kW). There are indications that prices peaked in 2008 and have reduced substantially in 2009 and 2010 (Nielsen et al. 2010).

Operations and Maintenance Costs

There are four major cost components of operation and maintenance (O&M) for wind turbines in Denmark: insurance, repair, service agreement, and land rent/administration. Each cost component accounts for approximately 25% of O&M costs over the lifetime of a wind power plant. The expected lifetime costs for O&M for a wind project built in 2008 are €12/MWh ($17/MWh) (Nielsen et al. 2010).

Financing Costs

The model uses project financing with 80% annuity-based debt. Privately owned wind turbines in Denmark are generally financed with an overdraft facility. All income is placed in the overdraft facility and the wind turbine owners do not have direct access to the funds. All expenditure and payment of returns on investments must be approved by the creditor.

Good projects can be 100% debt financed in Denmark, but it is the norm that projects are approximately 80% debt financed. An acceptable payback time on loans to onshore wind projects is no more than 15 years.

The interest rate in 2008 on overdraft facilities for onshore wind power projects was approximately 5% fixed for 5 years. Interest rates for onshore wind power projects are generally low compared to many other business ventures because they are considered to have good liquidity. Wind turbines are considered low risk ventures as there are good facilities available for managing risk factors in wind power projects.

An equity rate of between 9 and 11% is normal for new onshore projects in Denmark. This allows for a risk premium of between 5 and 7%. This again represents the relatively low risk in onshore power projects when compared to the average risk premium on the OMX 20 on the Danish stock exchange, from 1983 to 2002, which was 7.2%[13] (Saabye, 2003).

Revenues and Incentives

The main sources of revenue from onshore wind turbines are the sale of power through Nord Pool and a price supplement subsidy in the form of a feed-in tariff. Onshore turbines can enter into fixed price agreements with balancing agents for up to five years[14]. These fixed price agreements are set according to the forward market on Nord Pool.

Source of Data

Data is sourced from the publication, *Economy of Wind Turbines*, Nielsen et al. 2010 and interviews with banks and project developers.

Offshore

Project Features

No offshore projects were commissioned in Denmark in 2008, but three were either in the planning or construction phases.

Offshore wind farms are generally developed through government concessions that are awarded on the basis of a bidding process. The lowest price per kWh bid for the first 50,000 full load hours of production is awarded the concession. After the first 50,000 full load hours, the wind farm sells its power on the open market. Horns Rev I and II and Rødsand I and II were awarded using a bidding process. A bidding round for a new offshore wind farm near Anholt was completed in June 2010. It has a capacity of 400 MW and must be in production by December 31, 2012.

"Open door"[15] wind farms are also permitted. If approval is granted to build an "open door" wind farm, then the same incentive program for land based wind turbines applies. Two "open door" wind farms have been built to date.

Investment Costs

The investment costs for developers of offshore wind farms in Denmark are approximately €2,700/kW to €3,000/kW ($3,753 to $4,170/kW) for large wind farms of approximately 200 MW under the concessionary bidding process.

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[13] Saabye, N., *Risikopræmie på aktier*, 2003, National Bank of Denmark

[14] New products are appearing, offering fixed prices for 10 years.

[15] Open door projects are defined as offshore projects built outside of the public bidding process for offshore wind power plants. In addition to the two wind farms, one offshore power plant has been built using the open door application process.

The cost of connecting concessionary offshore wind farms to the national power grid and the transformer platform are socialized in Denmark, which reduces the total investment for project developers. Costs for performing environmental impact assessments and preliminary geological assessments of the seabed are also socialized.

Operations and Maintenance Costs

Operational costs for offshore wind farms are uncertain due to the limited statistical data and the steep experience curve for operating offshore wind parks. Average operating and maintenance costs over the lifetime of large offshore wind farms in Denmark range from €18/MWh ($25/MWh) to €20/MWh ($28/MWh) depending on local conditions.

Financing Costs

Large offshore wind farms in Denmark are financed over the balance books of the project developers. Loans from the Nordic Investment Bank have been utilized for all the concessionary offshore farms, though not in the form of project financing. Concessionary offshore wind farms are typically financed with an equity share above 50%.

The cost of equity for utilities in Denmark has been calculated at approximately 11.2%, while the cost of debt is between 4.5 and 5.5% (Nielsen et al. 2010).

Revenues and Incentives

Concessionary offshore wind farms receive a fixed price for power produced for the first 50,000 full load hours. The fixed price is determined in the bidding process. The bid price is not index regulated; it is determined after the first 50,000 full load hour revenues have occurred from sales through the Nord Pool power exchange. The winning bid price for Horns Rev II was €0.069/kWh ($0.096/kWh) and for Rødsand II €0.085/kWh ($0.118/kWh). A price supplement to the market price is provided by the system operator to meet the bid price. If the market price is higher than the bid price, the wind farm must pay the difference to the system operator.

Non-concessionary or "open door" offshore wind farms receive €0.034/kWh ($0.047/kWh) for the first 22,000 full load hours as well as the other available subsidies for onshore turbines.

Source of Data

The data on the total costs of building Horns Rev II and Rødsand II are derived from publicly available information, interviews with experts on developing offshore wind farms in Denmark, interviews with offshore wind owners, interviews with financiers of offshore wind farms, and calculations based on bid prices.

Model Input Assumptions

The following tables outline the modeling assumptions used for onshore and offshore wind energy in Denmark.

Table 2-5. Wind energy project features in Denmark

		Onshore 2007[16]	Onshore 2008	Offshore 2007[17]	Offshore 2008[18]
Unit size	MW	-	2.3	2.3	2.3
Number of turbines	N	-	3	91	90
Production	Full load hours	-	2,700	4,300	3,865
Economic life	Years	-	20	25	25
Investment costs	€/kW ($/kW)	-	1,250 (1,738)	2,844 (3,953)	3,000 (4,170)
O&M costs fixed	€/kW ($/kW)	-	-	-	-
O&M costs variable	€/MWh ($/MWh)	-	12 (17)	20 (28)	18 (25)
Decommissioning costs	€/kW ($/kW)	-	-	-	-
Other costs	€/MWh ($/MWh)	-	3(4)	-	-

Source: Economics of Wind Turbines, Nielsen et al. 2010

Table 2-6. Wind energy financing terms in Denmark

		Onshore 2007	Onshore 2008	Offshore 2007	Offshore 2008
Return on debt	%	-	5.0%	5.5%	4.5%
Return on equity	%	-	11.0%	11.2%	11.2%
Debt share	%	-	80%	45%	26%
Equity share	%	-	20%	66%	74%
WACC	%	-	5.2%	8.8%	9.5%
Loan duration	Years	-	13	10	13
Corporate tax rate	%	-	25%	25%	25%
FX rate	USD/€		1.39	1.39	1.39
FX rate	DKK/€	-	7.353	-	7.353

Sources: Nielsen et al. 2010, interviews with banks and export credit funds.

[16] No new wind turbines were erected in Denmark in 2007

[17] No offshore turbines were built in 2007 or 2008. There were, however, 3 offshore farms either under construction or in the planning phase. Two of the farms fell under the government concessionary program, while the third was an "open door" project. The final investment decision was made for Horns Rev II in 2007; therefore, the figures are based on estimated costs for Horns Rev II. The investment decision for Rødsand II was made in 2008 and this provides the basis for costs in that year.

[18] The example used here is calculated from the bid price for Rødsand II as the construction agreements were entered into in 2008.

Table 2-7. Wind energy revenue and policy incentives in Denmark

		Onshore 2007	Onshore 2008	Offshore 2007	Offshore 2008
Market price electricity	€/MWh ($/MWh)	-	44.7 (62.1)	28 (39)	44.7 (62.1)
Market price certificates	€/MWh ($/MWh)	-	N/A	-	N/A
FIT revenue	€/MWh ($/MWh)	-	37 (51)	70 (97)	85 (118)
FIT policy period	Full load hours	-	22,000	50,000	50,000
Upfront tax-based subsidy before tax	%	-	N/A	N/A	N/A
Production-based after tax credits	€/MWh ($/MWh)	-	N/A	N/A	N/A
Production-based after tax credit policy period	€/MWh ($/MWh)	-	N/A	N/A	N/A
Depreciation period	Years	-	Max. 25% annually	Max. 25% annually	Max. 25% annually
Reactive power bonus	€/MWh	-	N/A	N/A	N/A
Low voltage ride through bonus	€/MWh	-	N/A	N/A	N/A

Sources: Nielsen et al. 2010, Danish Energy Agency 2008, Danish Energy Agency 2009

Cost of Wind Energy Generation

Cost Comparison

The data for wind power investments in Denmark in 2008 was used to calculate the levelized cost of energy and compare it to the Reference Case LCOE presented in Chapter 1. The Reference Case is a representative wind power project for all participating countries in Wind Task 26.

The impacts of six variables in the Reference Case are compared with the Danish case to identify how each variable influences the levelized cost of wind power in Denmark. The comparison between the Reference Case and the Danish case is shown in Figure 2-2 below. The LCOE for an average project in Denmark was €61 ($85) in 2008, which is €7 ($10) lower than the Reference Case LCOE at €68/MWh.

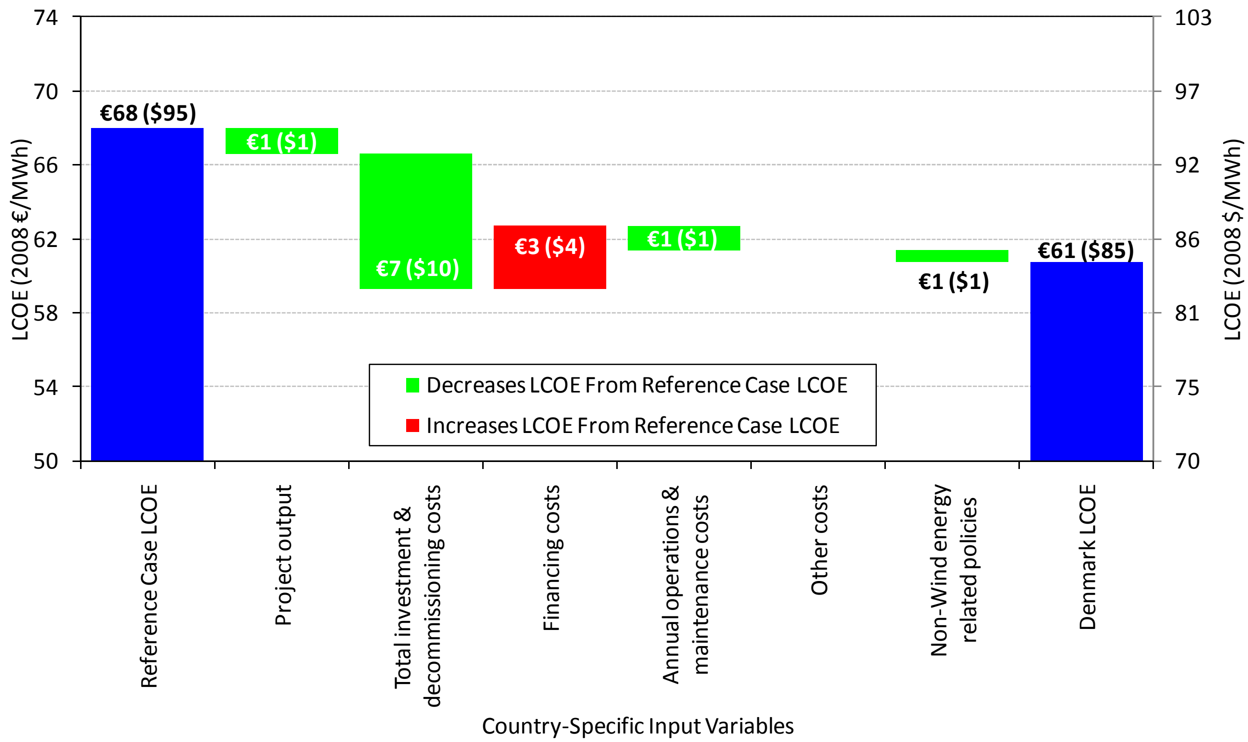

Figure 2-2. Wind energy costs in Denmark and the Reference Case in 2008[19]

Project Output

The project output in the Reference Case is a little over 2,600 full load hours, while the average production in 2009 for Danish projects commissioned in 2008 was slightly below 2,700 full load hours because 2009 was a poor wind year, with only 88% of the wind energy compared to an average year. If this is taken into account, then the average project for 2008 had approximately 3,000 full load hours annually, which improved the economy of the project and resulted in a reduction in the LCOE by approximately €5($7).

The higher number of full load hours for the Danish case, compared to the Reference Case, decreased the Danish LCOE by €1($1) per MWh.

Total Investment Costs

Investment costs in Denmark in 2008 were approximately €200/kW ($278/kW) lower than in the Reference Case. The major reason for project costs being 15% lower in Denmark is that grid connection costs in Denmark are paid by the grid company.

The grid company pays connection costs from the point of coupling to the grid. This includes costs for substations and transformers. The project owner pays for costs from the turbine to the coupling point. If an area is identified as a wind turbine area in spatial planning regulations, then

[19] Data labels are rounded to nearest whole numbers. Therefore, the sum of input variables may differ slightly from the total Reference Case – Country LCOE differential (due to rounding).

the responsible grid company must extend the grid to allow for connection at this point. This must be done at the expense of the grid company. This regulation can reduce overall project costs substantially and is illustrated in Figure 2-3 below.

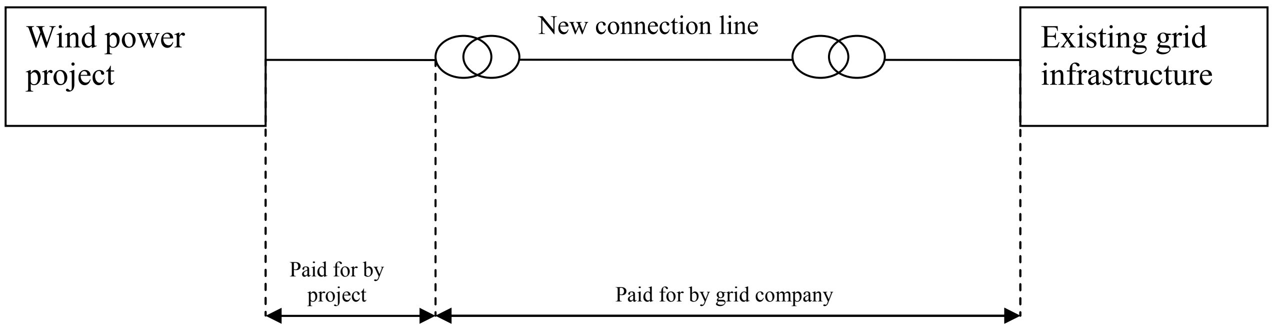

Figure 2-3. Illustration of Danish model for cost allocation of connection costs

Other factors that may reduce investment costs compared to the Reference Case are the favorable geological conditions for constructing foundations, the existence of a strong, local turbine manufacturing industry, an experienced project development sector, and well developed regulation for wind turbines in spatial planning and environmental impact assessments.

Financing Costs

Financing costs in Denmark are more expensive than in the Reference Case. The required return on equity in Danish projects was 11.0% compared to 10.0%, and the average interest rate on debt for wind power projects was the same ratio as debt financing when compared with the Reference Case.

The interest rate on debt in Danish projects is an expression of the perceived low levels of risk associated with financing wind turbines due to their good liquidity in Denmark and the market availability of efficient risk management products for wind power projects. The higher cost of equity in Denmark is a result of a higher exposure to price risk on the power market since the feed-in tariff supplements the market price, rather than guaranteeing remuneration, which occurs in most other countries with feed-in tariffs. There are no support schemes available for soft loans etc. in Denmark that can reduce financial costs.

Financing costs increase the LCOE in Denmark by approximately €3 ($4) compared to the Reference Case.

Operations and Maintenance Costs

Operation and maintenance costs in Denmark are only represented as a variable cost. A comprehensive study, in 2009 and 2010 (Nelson et al, 2010), indicated that operation and maintenance costs for turbines erected in 2008 would be approximately €12/MWh ($17/MWh) over the project's technical lifetime.

Operation and maintenance costs reduce the LCOE for Danish projects by 1€ ($1) relative to the Reference Case.

Other Costs

Other costs in Denmark refer to balancing costs. There is a subsidy for balancing costs in Denmark of €3/MWh ($4/MWh), which is assumed to equal the actual balancing costs of a wind turbine. Other costs have little effect on the LCOE relative to the Reference Case

Non-Wind Energy Policy

In the Danish case, non-wind energy policy refers to corporate taxes and the deduction of interest payments from taxable income. Denmark has a lower corporate tax than the Reference Case, so it can deduct a large portion of interest payments from taxable income. In addition, it has a high debt-to-equity ratio in wind projects. This reduces the LCOE by €1/MWh ($1/MWh) compared to the reference case.

The Danish rules on depreciation are not reflected in the calculations. In Denmark, the value of industrial equipment, which includes turbines, may be depreciated annually by a maximum of 25% of their residual value. This reduces the non-wind energy policy costs in a linear depreciation. This reduction has not been calculated.

Revenues and Wind Energy Policies and Incentives

The model's financial gap calculation is used to compare the value of the Danish revenue variables to the wind energy policies and incentives variables. The financial gap is first calculated without any revenue or any wind energy policies and incentives variables. Next, the financial gap is recalculated including only the revenue variables. Lastly, the financial gap is recalculated including the wind energy policies and incentives variables. This incremental process identifies the relative value of revenue variables to policy incentive variables.

Figure 2-4 compares the revenue variables to the policy incentive variables, and together, how they constitute the Danish LCOE. Of the €61/MWh ($85/MWh), approximately €43/MWh ($60/MWh) is covered by revenue sources (electricity sales), while €24/MWh ($33/MWh) is covered by incentives in the form of the feed-in tariff supplement over the projects lifetime. In relative terms, around 2/3 of the Danish LCOE is covered by revenue components, while the remaining 1/3 is covered by the feed-in tariff.

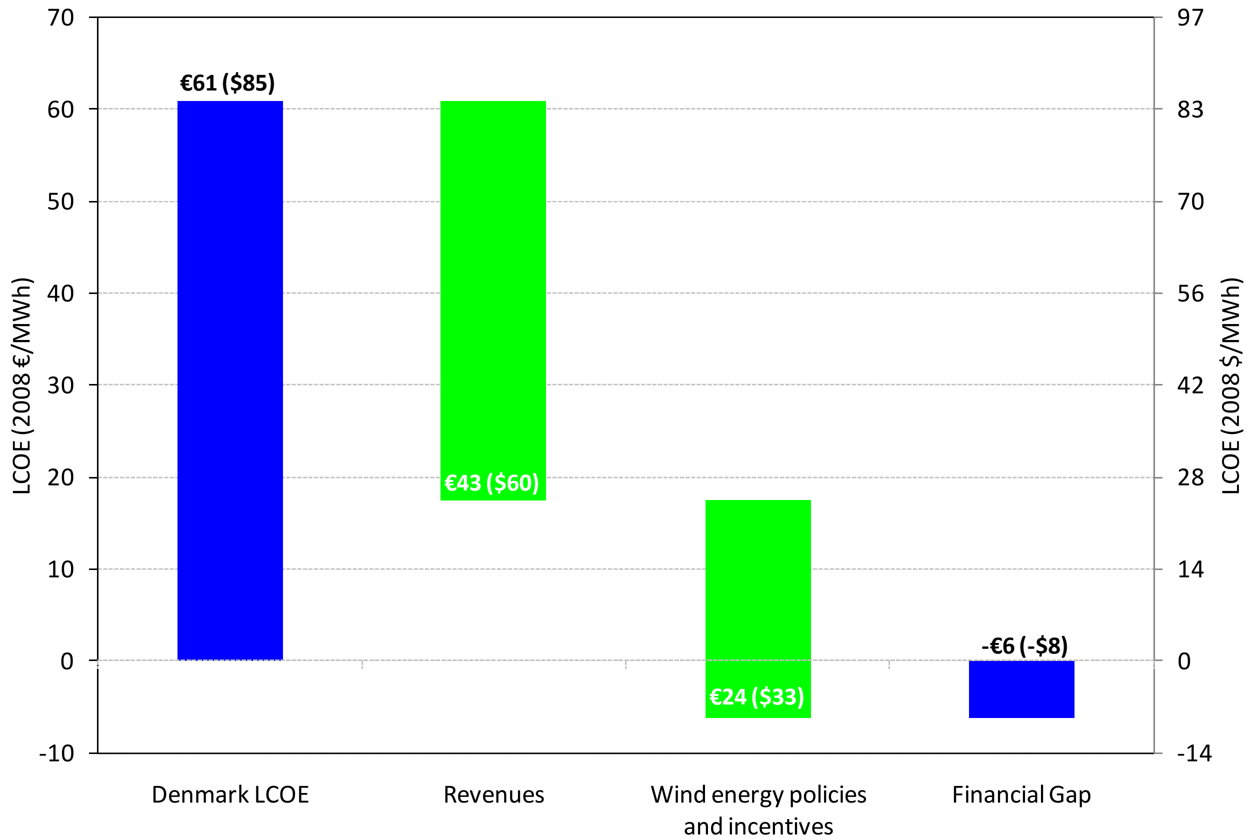

Figure 2-4. Danish revenues and wind energy policies and incentives in 2008[20]

The financial gap in the Danish modeling analysis is approximated at -€6/MWh (-$8/MWh). This suggests that on average, wind project developers and investors in Denmark receive sufficient cash flow from electricity revenue and wind energy policy incentives to meet the financial requirements for developing and investing in wind power projects.

Summary of Wind Projects in Denmark

Interest in investing and deploying onshore wind turbines has been revived since the introduction of new regulations for remuneration of wind turbines in 2008. Even though interest in onshore wind power is increasing, government focus is firmly on introducing offshore wind farms. A short term target of 800 MW of offshore wind capacity by the end of 2012 was set in 2008. The land based target was set at 175 MW for new onshore capacity and 175 MW for repowered capacity.

The cost of wind power in Denmark is lower than the Reference Case primarily due to lower investment costs, but lower financial and operational costs contribute as well. The cost of onshore wind power is expected to be lower in the near future due to lower prices for turbines. Early indications are that the levelized cost for wind power in 2009 was €59/MWh ($82/MWh)

[20] Data labels are rounded to the nearest whole numbers. Therefore, the sum of the revenues, wind energy policies and incentives, and the financial gap may differ slightly from the country LCOE.

compared with €61/MWh ($85/MWh) in 2008. This primarily is due to lower turbine costs, but the financial gain of cheaper turbines has been reduced by lower electricity prices. The financial gap for turbines erected in 2009 is estimated to be -€5/MWh (-$7/MWh). Despite this slight decrease, onshore wind power in Denmark remains an attractive investment under the current feed-in tariff.

The levelized costs for offshore are calculated on the basis of the winning bid price for each project. The cost of offshore wind power in Denmark increased by 15% in 2008 compared to 2007. This most likely was due to increasing turbine costs and bottlenecks in the supply of offshore construction vessels, higher cable prices, and increasing costs for steel and commodities. Table 2-8 below provides a summary of the cost of wind power in 2007 and 2008.

Table 2-8. Summary of levelized cost of electricity for Danish wind power in 2007 and 2008[21]

		Onshore 2007	Onshore 2008	Offshore 2007	Offshore 2008
Levelized cost of energy	€/MWh ($/MWh)	-	61 (85)	70 (97)	81 (113)
Total revenues and wind energy policies and incentives	€/MWh ($/MWh)	-	67 (93)	67 (93)	79 (110)
Financial gap for developer	€/MWh ($/MWh)	-	-6 (-8)	3 (4)	2 (3)

Though prices have fallen for components and raw materials since 2008, along with the appearance on the market of more offshore turbines, the cost of offshore wind power in Denmark is expected to increase. This is due partially to the availability of increasingly higher subsidies in the United Kingdom and Germany, which has increased the opportunity costs of investing in Danish offshore projects. Other reasons for increasing prices are the small market for offshore wind in Denmark in comparison to the major European offshore markets; the policy of tendering single offshore projects with relatively long intervals between tenders, which increases transaction costs for bidders; and the low level of competition in the bidding process (only two major market participants exist in the Danish offshore sector). The division of risk in the Danish concessionary process appears to be an important factor in increasing the cost of offshore wind power in Denmark and reducing the attractiveness of the Danish offshore power market for investors.

Another reason for the increased costs of offshore wind power in Denmark is that companies may have submitted bids at breakeven prices or very low levels of income to gain experience with offshore wind power so they can profit from the experience in more lucrative markets, such as the UK. This would make the levelized cost predictions in Table 2-8 lower than they are in reality.

There also are indications that the budgeting of offshore wind farms has been problematic and that many have overreached the original budget. If this is the case, then the calculation of the levelized costs based on the original bid price would result in a lower levelized cost than in reality.

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[21] As previously mentioned, data labels are rounded to the nearest whole numbers. Therefore, the sum of the revenues, wind energy policies and incentives, and the financial gap may differ slightly from the country LCOE.

The winning bid price for the 400 MW Anholt offshore wind farm was €141/MWh ($196/MWh). This represents a doubling of the price the state pays for offshore wind power compared to 2007.

Technical issues such as increasing distances from shore, and sites in deeper water, may also influence future investment costs, but these may be offset by technical improvements and learning curves.

It is likely that government-sponsored concessions to produce offshore wind power will make up the bulk of offshore investments in the future. The economics of “open door” offshore plants are generally not attractive unless they are situated very near the coast and are in very shallow water, so called “feet in the water” projects.

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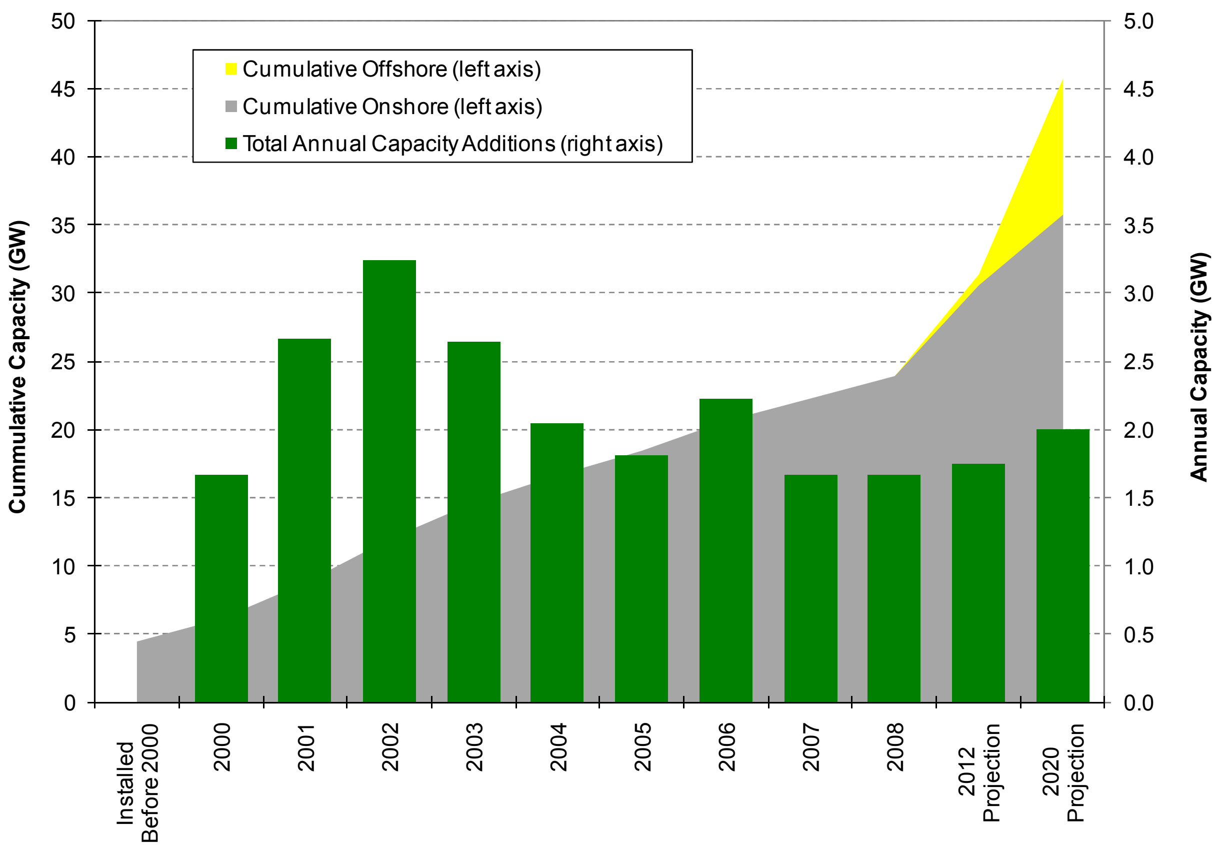
Chapter 3: Germany

Overview of Wind Industry in Germany

Capacity, Energy Production, Near-Term Targets

The development of wind energy in Germany began in the early 1990s. Since then, more than 23.9 GW of onshore wind energy capacity has been installed. Annual installations have slightly decreased since 2002, the year with the highest annual installations at 3.2 GW. Total onshore capacity is expected to increase to 30.6 GW by the end of 2012. The wind energy capacity projections in 2012 and 2020 are from the National Renewable Energy Action Plans (NREAP) of the European Member States (European Commission 2010).

In 2009, the construction of the first offshore wind farm, Alpha Ventus, was completed. Because of this, offshore development can be expected to begin in the near future. The German government has announced a goal of approximately 2.5 GW of cumulative offshore wind capacity by the end of 2015.



Sources: BMU, Leitszenario 2009 and European Commission 2010

Figure 3-1. Cumulative and annual wind installations in Germany

In 2000, electricity production from wind energy was 1.6% of the gross domestic electricity production in Germany. During the past eight years, this share has significantly increased to

6.2%. Taking into account the estimated increase of wind energy production capacities and the efforts of the German government to improve efficiency of electricity consumption, this share is expected to increase continuously into the future.

Table 3-1 presents historical and projected *cumulative* wind energy installed in Germany.

Table 3-1. Cumulative GW installed in Germany

	Installed Before 2000	2000	2001	2002	2003	2004	2005	2006	2007	2008	Projection 2012	Projection 2020
Onshore	4.4	6.1	8.8	12.0	14.6	16.6	18.4	20.6	22.2	23.9	30.6	35.8
Offshore	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	10.0

Source: BMU, Leitszenario 2009 and European Commission 2010

Table 3-2 shows historical and projected *annual* capacity additions.

Table 3-2. Annual GW installed in Germany

	Installed Before 2000	2000	2001	2002	2003	2004	2005	2006	2007	2008	Projection 2012	Projection 2020
Onshore	4.4	1.7	2.7	3.2	2.6	2.0	1.8	2.2	1.7	1.7	1.4	0.3
Offshore	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	1.7

Source: BMU, Leitszenario 2009 and European Commission 2010

Revenue and Policy Incentives

Wind energy in Germany has been supported by the Renewable Energy Law (EEG) since 2000. The law was amended in 2004 and 2008. The last two versions are briefly described below following a general description on the EEG mechanism.

General

The EEG regulates the support of all renewable energy sources, including onshore and offshore wind energy. The produced energy is sold under a fixed feed-in tariff.

The onshore feed-in tariff consists of two steps: a lower basic tariff and a higher premium tariff. Every project will receive the higher tariff for at least five years. The duration of the premium tariff is dependent on the quality of the project site. For each different wind turbine type, a reference annual energy production (calculated reference for a fixed reference site[22]) is announced. After five years of operation, this reference energy production will be compared to the actual production of the turbine at the project site. The duration of the premium tariff is extended by two months for each 0.75% that the project site's energy production is below 150% of the reference site's energy production. The project has to reach an annual energy production of at least 60% of the reference production to participate on the EEG.

[22] Note that the German reference site does not refer to the Reference Case used in this report.

The offshore tariff also consists of two steps. The higher premium tariff will be paid for at least 12 years. If the offshore wind farm is located at a site with a water depth greater than 20 meters, and/or a distance from the coast that is greater than 12 nautical miles, the duration of the premium tariff increases. For each meter of water depth greater than 20 m, the duration of the premium tariff is extended by 1.7 months. Additionally, the duration of the premium tariff extends by one half of one month for each nautical mile of distance from the coast in excess of 12 nautical miles.

EEG 2004

The onshore basic tariff was €55/MWh ($76/MWh), whereas the premium tariff was €87/MWh ($121/MWh). Both tariffs within EEG 2004 decreased with an annual regression rate of 2%. The duration of the premium tariff for new sites was determined according to the mechanism mentioned above. For repowering projects, the duration continued for each 0.60% that the actual energy production was below 150% of the reference energy production.

The basic offshore tariff was approximately €62/MWh ($86/MWh), whereas the premium tariff was €91/MWh ($127/MWh). The duration of the premium offshore tariff is determined according to the general EEG mechanism described above.

EEG 2009

The EEG onshore basic tariff was updated in 2009 to €50.2/MWh ($69.8/MWh) and the premium tariff changed to €92/MWh ($128/MWh). Both tariffs will decrease annually using a regression rate of 1% based on the year of construction of the wind farm. Therefore, a project built in 2009 receives a premium tariff of €92/MWh ($128/MWh), whereas a project built in 2010 will have a premium tariff of €91/MWh ($126/MWh). If the project is a repowering project, there is an additional bonus of €5/MWh ($7/MWh). In certain instances, wind turbines, which are able to support electricity grids (e.g. low frequency), receive a bonus of €5/MWh ($7/MWh) as will new projects installed before 2014. The bonus increases to €7/MWh ($10/MWh) for existing projects, if the wind turbines are optimized until 2010.

Offshore wind farms benefit from a basic tariff of €35/MWh ($49/MWh). The premium tariff for offshore wind farms is €130/MWh ($181/MWh) and is paid for 12 years. If a project is constructed before 2016, an additional bonus of €2/MWh ($3/MWh) will be paid. The extension of the premium tariff follows the general EEG mechanism.

Typical Onshore and Offshore Wind Energy Projects in Germany

Onshore

The quality of onshore sites for wind energy projects in Germany varies substantially. The good quality sites are located in the North and on the Baltic Sea coasts. Even though the site quality decreases the further south a project is located, the majority of sites are located in the south of Germany. The following describes a typical German wind energy project in 2007. The quality of this site is relatively good compared to the average sites exploited in 2007. This site is expected to realize roughly 2,260 equivalent full-load hours.

Project Features

The average rated power of wind turbines installed in Germany in 2007 and 2008 was about 2 MW. Approximately 65% of the machines had a rated power of exactly 2 MW. The availability of suitable areas for the construction of wind farms in Germany was relatively low in 2007 and 2008. This resulted in the installation of many small wind farms with a minor number of wind turbines installed. The biggest projects installed in these years had a rated power of 30 MW. Furthermore, quite a high number of single turbines were installed in these years. A wind farm consisting of five turbines was chosen for the model.

In recent years, wind energy projects at sites in the south of Germany have been developed. Because of the lesser quality of these sites in comparison to the German reference site, a project site was chosen with a quality that is 90% of the German reference site.

Investment Costs

Investment costs depend on the rated power, the rotor diameter of the wind turbine as well as the hub height, and the general design concept of the wind turbine (ratio between rated power and rotor diameter). The German project turbine has a rated power of 2 MW, a hub height of 100 meters, and a rotor diameter of 75 meters. In 2007, the total investment for such a machine was approximately €1,259/kW ($1,750/kW) including all additional investments like the foundation, grid connection, etc.. Due to increasing prices, investment in the same machine increased from approximately €1,100/kW ($1,529/kW) to roughly €1,370/kW ($1,904/kW) in 2008.

Operations and Maintenance Costs

O&M costs include maintenance by the turbine manufacturer and other third party service providers, periodic inspection by external experts, insurances, technical and economic management, the cost of energy consumption, land rent, and other costs. In 2007, annual O&M costs were €45.71/kW ($63.5/kW) while annual O&M costs of €46.33/kW ($64.4/kW) were incurred in 2008.

Financing Costs

An equity share of 30% was chosen for the model, and the debt share was 70%. No municipal participation was assumed. The return on equity was assumed to be 9.5% and 5.5% for the interest rate on debt. The low interest rates resulted from a low revenue risk rating since grid access was guaranteed with preferential feed-in, and there are guaranteed and fixed payments from the feed-in tariffs.

Revenue and Policy Incentives

The revenue is generated from the energy feed-in and the related tariff. The premium tariff for projects erected in 2007 was €81.9/MWh ($113.84/MWh) and the basic tariff was €51.8/MWh ($72/MWh). Based on project site quality, the premium tariff will be applied for 18.3 years.

Source of Data

Data is derived from EEG (2004), DEWI Magazine Nos. 32 (2008) and 34 (2009), and the scientific report for the abatement of EEG (2008) prepared by Deutsche WindGuard GmbH for ZSW. The value of the corporate tax is from Destatis.

Offshore

The following information is based on projections from 2008 for future offshore wind farms.

Project Features
The offshore project is assumed to have a cumulative power of 60 MW from the installed capacity of 12 offshore wind turbines. The project is located in the North Sea, approximately 40 kilometers from the East Frisian Island of Borkum. The water depth at this site is around 30 meters. The distance from the coast and the water depth require offshore wind turbines, with a rated power of approximately 5 MW, to realize an economic benefit. This site has an expected 3,700 equivalent full-load hours.

Investment Costs
Distance and the deep water investment costs for German offshore wind farms are higher in comparison to the international average at (€3,230/kW) ($4,490/kW). These costs include wind turbines, foundations, a substation, and transmission cables. The grid connection to the onshore grid is the responsibility of the grid operator. Therefore, there are no connection costs for the connection to the onshore grid in the project investment costs.

Operations and Maintenance Costs
Compared to onshore operation and maintenance costs, offshore O&M costs are substantially higher. Because of the distance from the coast, there are increased transportation expenses for personnel and materials from the mainland to the wind turbines offshore. In addition, O&M maintenance costs include external and internal staff, necessary inspections, insurances, and costs of economic and technical management as well as the cost of ship traffic observations.

Annual O&M costs of the German offshore wind energy projects are expected to be €123/(kW) ($171/kW).

Financing Costs
In comparison with onshore projects, investors of offshore projects require higher returns. The return on equity (12%) as well as the interest on debt (6.5%) are higher for offshore projects than for onshore. The shares of equity (30%) and debt (70%) are constant in comparison with the assumed onshore project. In reality, this might be slightly different due to the structure of project funding (e.g., project financed versus balance sheet financed projects).

Revenue and Policy Incentives
Electricity from offshore wind energy is refunded by EEG feed-in tariffs. For the assumed model, the premium tariff is €91/MWh ($127/MWh) and the basic tariff is €61.9/MWh ($86.0/MWh) according to the EEG 2004. Therefore, the premium tariff will be paid for 14.5 years based on the project site's distance from the coast and the water depth.

Source of Data
Data is derived from EEG (2004), the scientific report for the abatement of EEG (2008), prepared by Deutsche WindGuard GmbH for ZSW.

Model Input Assumptions
Tables 3-3 through 3-5 provide the modeling assumptions used in the levelized cost of energy analysis that follows.

Table 3-3. Wind energy project features in Germany

		Onshore 2007	Onshore 2008	Offshore 2007	Offshore 2008
Unit size	MW	2	2	N/A	5
Number of turbines	N	5	5	N/A	12
Production	full load hours	2,260	2,260	N/A	3,700
Economic life	years	20	20	N/A	20
Investment costs	€/kW ($/kW)	1,259 (1,750)	1,373 (1,908)	N/A	3,230 (4,490)
O&M costs fixed	€/kW ($/kW)	45.71 (63.5)	46.33 (64.4)	N/A	123 (171)
O&M costs variable	€/MWh($/MWh)	-	-	N/A	-
Decommission costs	€/kW ($/kW)	1.49 (2.07)	1.52 (2.11)	N/A	-
Other costs	€/MWh ($/MWh)	-		N/A	-

Source: Deutsche WindGuard

Table 3-4. Wind energy financing terms in Germany

		Onshore 2007	Onshore 2008	Offshore 2007	Offshore 2008
Return on debt	%	5.5	5.5	N/A	6.5
Return on equity	%	9.5	9.5	N/A	12.0
Debt share	%	70	70	N/A	70
Equity share	%	30	30	N/A	30
WACC	%	5.6	5.6	N/A	6.8
Loan duration	years	13	13	N/A	15
Corporate tax rate	%	29.8	29.8	N/A	29.8
FX rate	$US/€	1.39	1.39	N/A	1.39

Source: Deutsch WindGuard, Destatis

Table 3-5. Wind energy policy and revenue incentives in Germany

		Onshore 2007	Onshore 2008	Offshore 2007	Offshore 2008
Market price electricity	€/MWh ($/MWh)	-	-	N/A	-
Market price certificates	€/MWh ($/MWh)	-	-	N/A	-
Average FIT revenue	€/MWh ($/MWh)	79 (110)	78 108	N/A	84 (117)
FIT policy period	Years	20	20	N/A	20
Upfront tax-based subsidy before tax	%	-	-	N/A	-
Production-based before tax credits	€/MWh ($/MWh)	-	-	N/A	-
Production-based before tax credit policy period	Years				
Depreciation period	Years	16	16	N/A	16
Reactive power bonus	€/MWh ($/MWh)	-	-	N/A	-
Low voltage ride through bonus	€/MWh ($/MWh)	-	-	N/A	-

Source: Deutsche WindGuard

Cost Comparison for a German Onshore Project (2008) to the Reference Case:
Figure 3-2 shows that the LCOE in Germany (€85/MWh) ($118/MWh) is substantially higher than in the Reference Case described earlier in this report. The reasons for this variation are illustrated below.

Cost of Wind Energy Generation

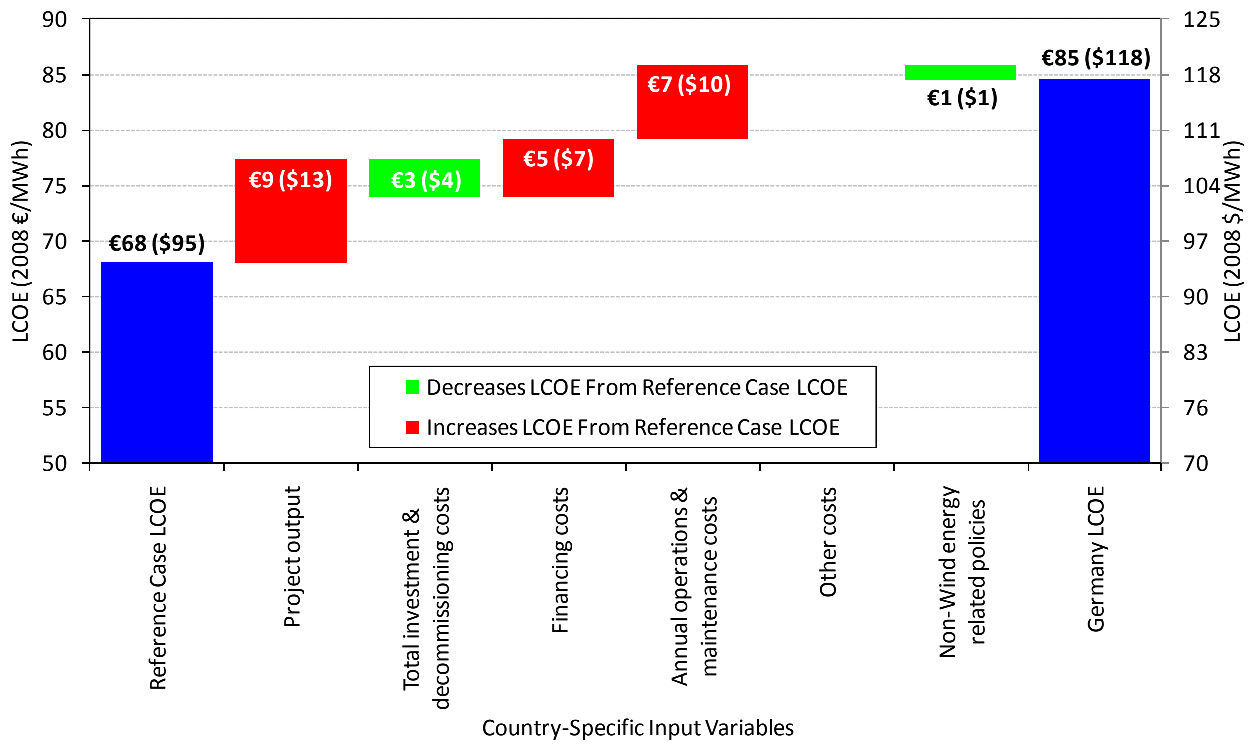


Figure 3-2. Wind energy costs in Germany in 2008[23]

Project Output
The major reason for the difference of LCOE can be found in the project output. The Reference Case capacity is nearly 2,630 full-load hours per year. However, the German base project full-load hours are significantly less at 2,260 per year.

Investment Costs
Investment costs for wind energy in 2008 in Germany were roughly €1,373/kW ($1,908/kW), which is €76 ($106) less than the Reference Case. In terms of LCOE, this equals a reduction of about €3/MWh ($4/MWh).

Operations and Maintenance Costs
Operation and maintenance costs of a German wind energy project are higher than in the Reference Case by approximately €7/MWh ($10/MWh). Several reasons for the additional costs

[23] Data labels are rounded to the nearest whole numbers. Therefore, the sum of input variables may differ slightly from the total Reference Case – Country LCOE differential (due to rounding).

include the commitment of periodic inspections and the small size of German wind farms, which leads to increased costs of stocking spare parts.

Financing Costs
The difference between the German onshore project and the Reference Case is roughly €5/MWh ($7/MWh) and occurs because of different financing structures.

Other Costs
No other costs are assumed.

Revenues and Support Mechanisms
Electricity produced by wind energy will achieve a fixed feed-in tariff according to the EEG. No other revenues can be expected for a German wind energy project as long as it is treated under either the EEG 2004 or the EEG 2009. Furthermore, no other incentives are intended or expected to support German wind energy projects.

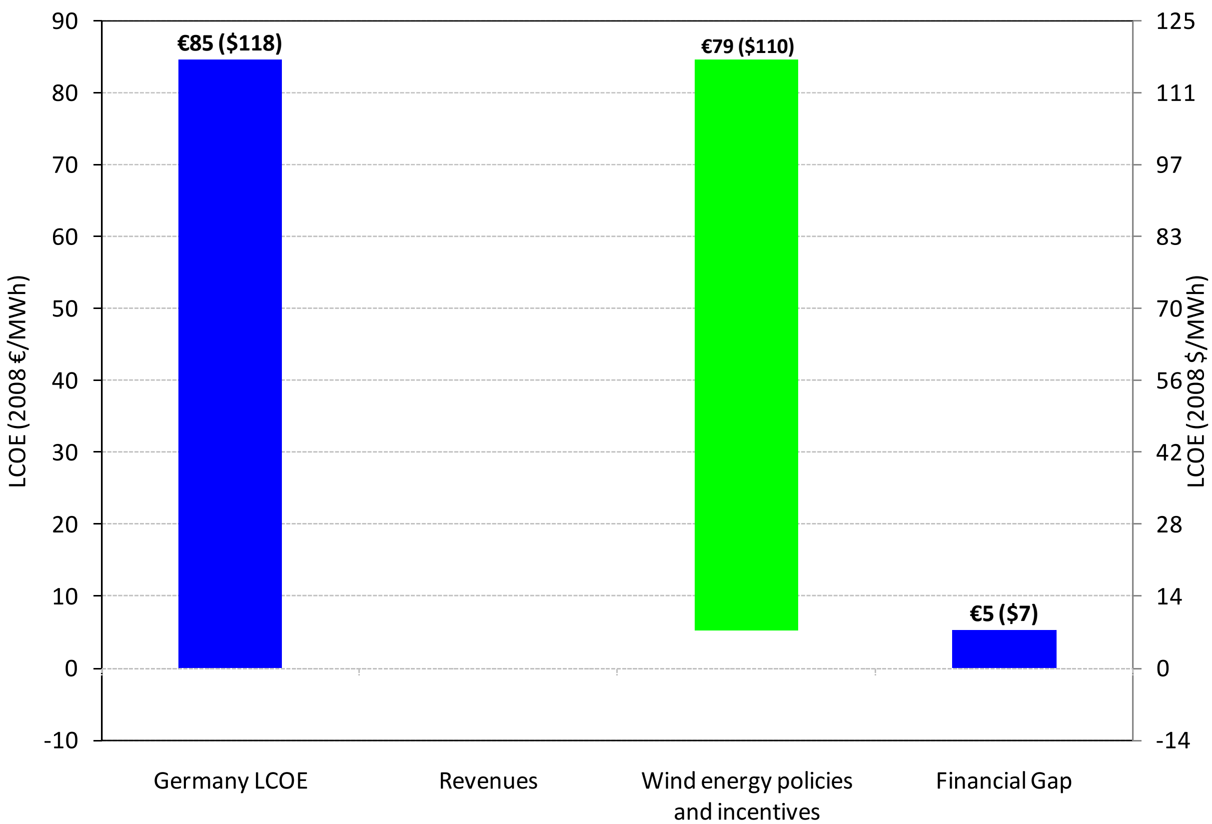


Figure 3-3. Wind energy revenue and policy incentives in Germany (2008)[24]

[24] Data labels are rounded to the nearest whole numbers. Therefore, the sum of the revenues, wind energy policies and incentives, and the financial gap may differ slightly from the country LCOE.

Financial Gap
As shown in Figure 3-6, there is a financial gap of €5/MWh ($7/MWh). The main reasons for this financial gap are the differences in full-load hours and in the operation and maintenance costs.

Summary
The chosen German onshore wind farm example consists of five wind turbines with a rated power of 2 MW. The full-load hours of the project are assumed to be 2,260. The model assumptions led to an estimated LCOE of €85/MWh ($118/MWh). The offered feed-in tariff results in a financial gap of approximately €5/MWh ($7/MWh) for the project developer. The level of the tariffs is regulated in the EEG.

Table 3-6. Summary of results for Germany[25]

		Onshore 2007	**Onshore 2008**	**Offshore 2007**	**Offshore 2008**
Levelized cost of energy	€/MWh ($/MWh)	79 (110)	85 (118)	N/A	135 (188)
Total revenues and wind energy policies and incentives	€/MWh ($/MWh)	79 (110)	79 (110)	N/A	84 (117)
Financial gap for developer	€/MWh ($/MWh)	-2 (-3)	5 (7)	N/A	46 (64)

[25] As previously noted, data labels are rounded to the nearest whole numbers. Therefore, the sum of the revenues, wind energy policies and incentives, and the financial gap may differ slightly from the country LCOE.

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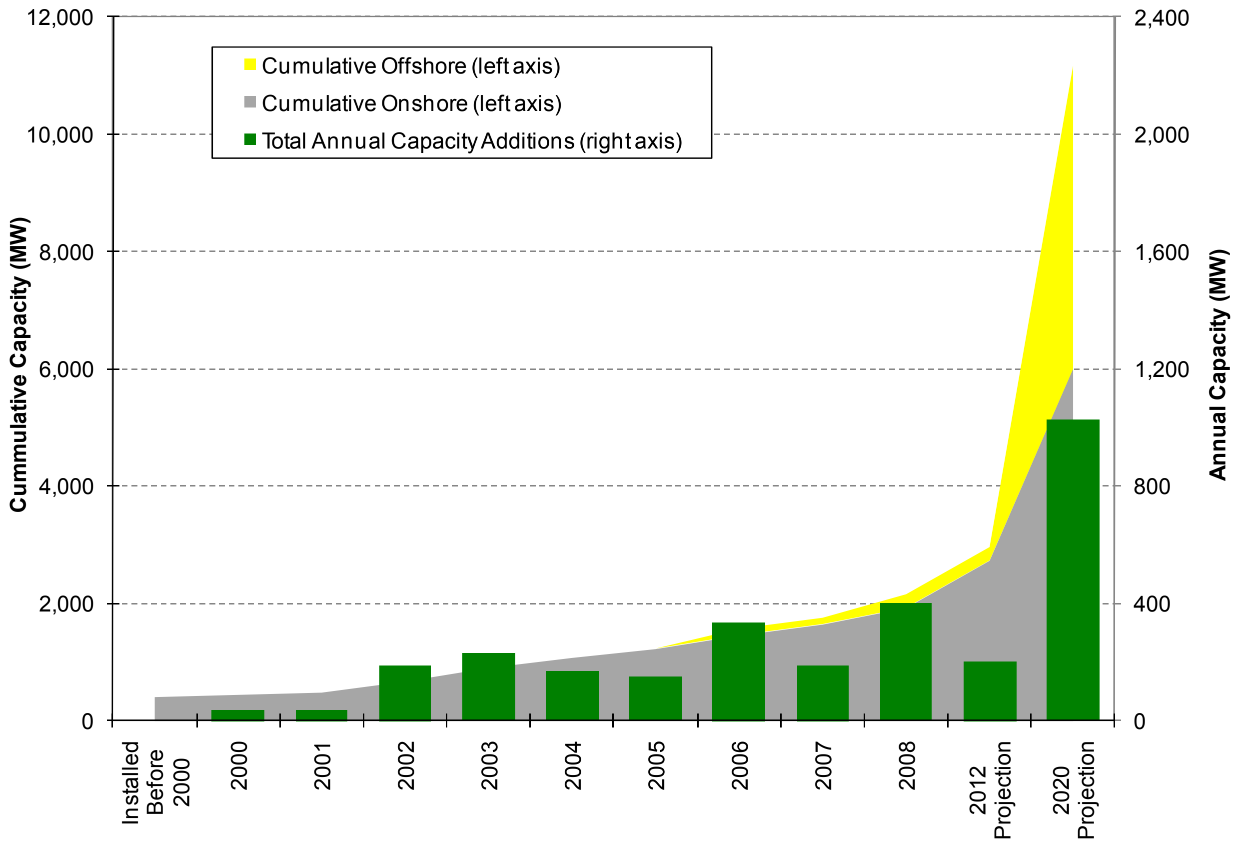
Chapter 4: Netherlands

Overview of Wind Industry in the Netherlands

Capacity, Energy Production, Near-Term Targets

The installed wind capacity has increased from 447 MW in 2000 to 2,121 MW at the end of 2008, of which 228 MW is offshore wind capacity. The annual wind energy production has risen from 0.8 TWh (2000) to 4.3 TWh (2008). In comparison, the total electricity consumption in the Netherlands in 2008 was 119 TWh. The near-term target for onshore wind is 2,000 MW of additional installed capacity between 2008 and 2012. This target coincides with the approximately 4,000 MW total capacity, installed or under construction. In 2009, a tender for 950 MW of offshore wind will be launched. Offshore wind has a target of 6000 MW installed capacity by 2020. However, to fulfill the obligation for the Netherlands under the Renewable Energy Directive of the European Union, just 5178 MW is projected in 2020.

Figure 4-1 and Tables 4-1 and 4-2 show the onshore and offshore cumulative and annual capacity installations, as well as projections of near-term and long term targets/goals by year. Note all capacity data is year-end data. The Netherlands does not have repowering targets.



Source: Statistics Netherlands, 2010 and Rijksoverheid, 2010

Figure 4-1. Cumulative and annual wind installations in the Netherlands

The annual installed capacity in 2000 was set to equal the year-end cumulative installed capacity in 2000. The net annual installed capacity shown in Table 2 is net of decommissioned wind energy projects. The net annual installed capacities, in the 2009 – 2012 and 2012 – 2020 periods, included in 4-2, represent the average annual installed capacity in these periods. The capacities given in the tables below are projections of installed capacities based on the Renewable Energy Action Plan of the Dutch government (Rijksoverheid, 2010).

Table 4-1. Cumulative GW installed in the Netherlands

	Installed Before 2000	2000	2001	2002	2003	2004	2005	2006	2007	2008	Projection 2012	Projection 2020
Onshore	0.409	0.447	0.485	0.672	0.905	1.075	1.224	1.453	1.641	1.921	2.727	6.000
Offshore	0	0	0	0	0	0	0	0.108	0.108	0.228	0.228	5.178

Source: Statistics Netherlands, 2010 and Rijksoverheid, 2010

Table 4-2. Net annual GW installed in the Netherlands

	Installed Before 2000	2000	2001	2002	2003	2004	2005	2006	2007	2008	Projection 2012	Projection 2020
Onshore	0.409	0.038	0.038	0.187	0.233	0.170	0.149	0.229	0.188	0.280	0.202	0.409
Offshore	0	0	0	0	0	0	0	0.108	0	0.120	0	0.619

Source: Statistics Netherlands, 2010 and Rijksoverheid, 2010

Revenue and Policy Incentives

Since 2008, a new feed-in premium scheme, SDE, is in force. Under the SDE scheme, a premium is paid on top of the wholesale electricity price to meet the actual electricity production costs for wind energy. Additional benefits from soft loan and tax incentives, which are applicable for investments in renewable energy technology, are considered in the SDE premium.

Typical Wind Energy Projects in the Netherlands

In the following, representative projects will be described for both onshore and offshore wind energy in the Netherlands.

Onshore

Project Features

Since 2003, the Netherlands has had a feed-in system that supports wind on the basis of full load hours. Until 2006, feed-in was provided for up to 18,000 full load hours per project for a maximum of 10 years. Since 2008, the feed-in support aims at projects with at least 2,200 full load hours. The average full load hours are about 2,000 hours/year, with a common range between 1,600 and 2,800 hours/year.

The Dutch onshore project shows the reference project used in calculations of the feed-in support.[26] The project sets the cost level at which the majority of the projects initiatives are financially viable. A typical size is a small wind farm of 15 MW. Most of the wind projects use a 2-3 MW turbine (90 meter rotor diameter), with hub heights of 60 to 80 meters. In some regions,

[26] Note that the "reference project" does not refer to the "Reference Case" used in this analysis.

a height limitation is imposed. In those regions, a 450-800 kW turbine, with a hub height of 40-60 meters, is common.

Investment Costs

Typical project investment costs range from €1,000/kW ($1,390/kW) to more than €1,600/kW ($2,224/kW), and, generally speaking, high investment costs correspond to high full load hours.

Operations and Maintenance Costs

The operational costs include a production dependent component of €9-12/MWh ($13-$17/MWh), typically with service contracts for the first five years of operation, and a capacity dependent component of €25/kW ($35/kW), which includes land rent and grid connection costs. The capacity dependent component can vary significantly between projects. The real operational costs are assumed to increase with 2% per annum.

Financing Costs

The model uses project financing with 80% annuity based debt, reflecting investments of project developers. An equity rate of 15% is assumed fair by the government (as the subsidy provider), with a debt rate of 6%. Utility companies mostly finance on their balance sheets. The corporate tax rate is 25.5%.

Revenue and Policy Incentives

The main revenues are electricity sales through long term contracts, primarily on the forward market, and feed-in premiums cover the financial gap. Generic additional incentives are given through soft loans and an energy investment allowance. The energy investment allowance is assumed to lower the equity share. Structures using this tax benefit vary, ranging from developers with lack of taxable income to those who use the funds for their benefit against a 42% income tax.

Source of Data

The data used for this task is the published data of the reference projects that are used in the calculations of the Dutch feed-in premiums (Lensink *et al.*, 2009, Cleijne *et al.*, 2010).

Offshore

Project Features

Offshore wind projects in the Netherlands can receive a building permit to erect a wind farm in a maximum area of 50 km^2. Typical offshore projects are, therefore, 100-300 MW in capacity. The net production delivered to the grid equals 3,300-4,000 full load hours. In 2008, the Prinses Amalia wind farm was completed. The presented data does not necessarily reflect the cost structure of that specific wind farm.

Investment Costs

The investment costs are in the range of €2,500-3,500/kW ($3475-4865/kW). The project that was completed in 2008 uses a rather small V90 with 2 MW due to limiting conditions in the permit that had been granted several years before.

Operations and Maintenance Costs

Operational costs show a large uncertainty, due to lack of hands-on experience by the operator. The costs are estimated at €90/kW ($125/kW) per annum.

Financing Costs

The model uses a project based financing structure, with 50% debt. The Prinses Amalia wind farm has been financed on the project basis. The assumed WACC approaches the cost of capital of balance financing, which has been used for another existing offshore wind farm , owned by Nuon/Shell and named OWEZ.

Revenue and Policy Incentives

The existing wind farms receive subsidies under the old MEP scheme: a fixed feed-in premium of €97 €/MWh (€135/MWh). Soft loans and an incentive subsidies apply.

Source of Data

The data is derived from press notices and other publicly available information, where the information gaps are covered by modeling exercises based on non-disclosed information.

Model Input Assumptions

Tabular presentations show input assumptions, onshore and offshore, for each year. Costs for 2007 projects are in $€_{2008}$. The market price of electricity in Table 4-5 includes transaction and balancing costs as well as discounts for long term contracts.

Table 4-3. Wind energy project features in the Netherlands

		Onshore 2007	Onshore 2008	Offshore 2007	Offshore 2008
Unit size	MW	1	15	120	N/A
Number of turbines	N	1	5	60	N/A
Production	(full load hours)	2,000	2,200	3,350	N/A
Economic life	(years)	20	20	15	N/A
Investment costs	€/kW ($/kW)	1,120 (1,557)	1,325 (1,842)	3315 (4,608)	N/A
O&M costs fixed	€/kW ($/kW)	40 (56)	24 (33)	92 (128)	N/A
O&M costs variable	€/MWh ($/MWh)	N/A	11 (15)	N/A	N/A
Decommission costs	€/kW ($/kW)	N/A	N/A	N/A	N/A
Other costs	€/MWh ($/MWh)	N/A	N/A	N/A	N/A

Table 4-4. Wind energy financing terms in the Netherlands

		Onshore 2007	Onshore 2008	Offshore 2007	Offshore 2008
Return on debt	%	5	5	5	N/A
Return on equity	%	15	15	12	N/A
Debt share	%	80	80	50	N/A
Equity share	%	20	20	50	N/A
WACC	%	6.0	6.0	7.9	N/A
Loan duration	(years)	10	15	10	N/A
Corporate tax rate	%	25.5	25.5	25.5	N/A
FX rate	($US/€)	1.39	1.39	1.39	N/A

Table 4-5. Wind energy policy and revenue incentives in the Netherlands

		Onshore 2007	Onshore 2008	Offshore 2007	Offshore 2008
Market price electricity	€/MWh ($/MWh)	58 (81)	56 (78)	59 (82)	N/A
Market price certificates	€/MWh ($/MWh)	N/A	N/A	N/A	N/A
FIT revenue	€/MWh ($/MWh)	6.63 (9.22)	28 (39)	97 (.135)	N/A
FIT policy period	(years)	10	15	10	N/A
Upfront tax-based subsidy before tax	%	37	20	44	N/A
Production-based before tax credits	€/MWh ($/MWh)	N/A	N/A	N/A	N/A
Production-based before tax credit policy period	(years)	N/A	N/A	N/A	N/A
Depreciation period	(years)	10	15	10	N/A
Reactive power bonus	€/MWh ($/MWh)	N/A	N/A	N/A	N/A
Low voltage ride through Bonus	€/MWh ($/MWh)	N/A	N/A	N/A	N/A

Unique Aspects of Wind Projects in Netherlands

Wind projects in the Netherlands have a long lead time, mainly due to the difficulties in obtaining the necessary permits.

Comparison of Wind Energy Costs in the Netherlands to the Reference Case
Cost Comparison

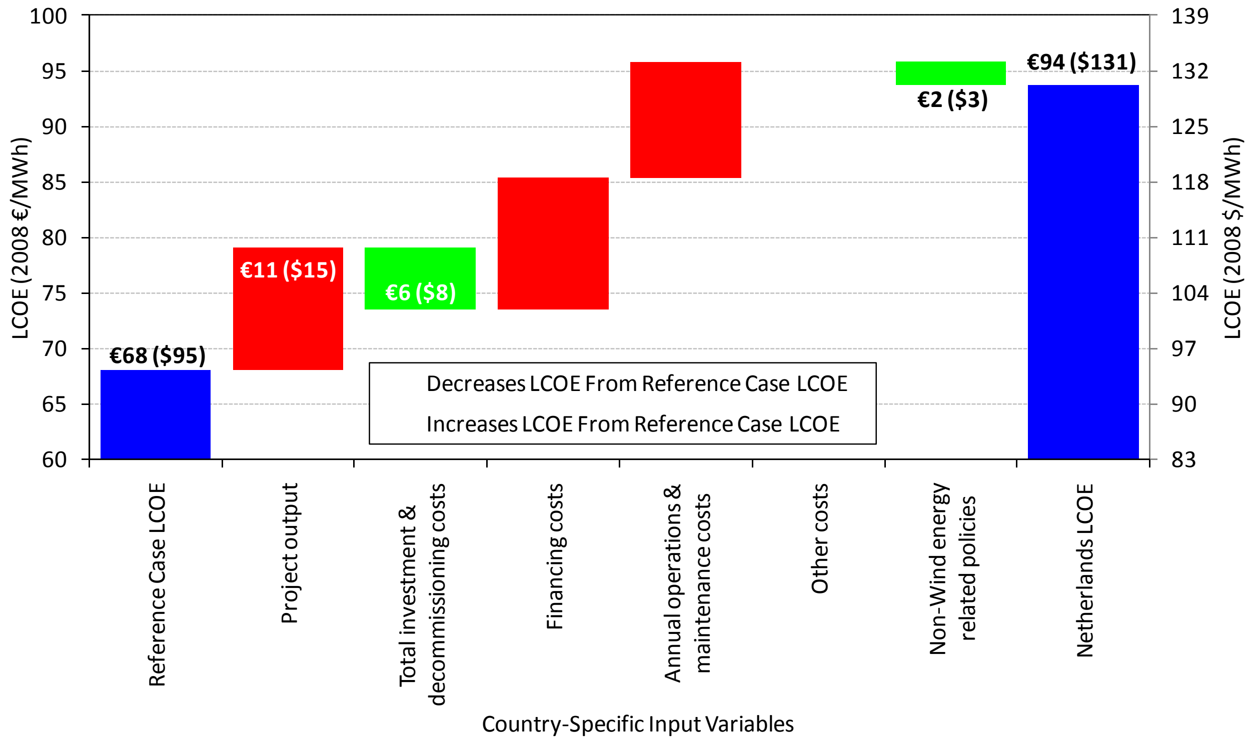


Figure 4-2. Graphical representation between the Netherlands and Reference Case[27]

Project Output
Wind turbines in the Netherlands have a load factor of about 25% (2,200 full load hours), which is lower than the 30% in the Reference Case. As the feed-in subsidy is capped to 2,200 full load hours (or even less, taking the specifics of the SDE regulation into account), there is limited incentive to produce more than 2,200 full hours. The more important factor remains the wind regime.

Cost of Wind Energy Generation
Investment Costs
The total investment costs might be related to the previous issue. There is limited incentive to produce more than 2,200 full load hours. It cannot be excluded that turbines are of slightly different designs and thus, slightly less expensive. For example, using the same generator but smaller rotor blades will reduce the investment costs and increase the number of full load hours.

[27] Data labels are rounded to the nearest whole numbers. Therefore, the sum of input variables may differ slightly from the total Reference Case – Country LCOE differential (due to rounding).

Operations and Maintenance Costs
The high operational costs are, in part, due to the high cost of land rent, which is about €10/kW ($15/kW) annually.

Financing Costs and Other Costs
Compared to the Reference Case, wind energy in the Netherlands also benefits from the relatively low corporate tax rate of 25.5%. Decommissioning costs are not taken into account.

Revenues and Support Mechanisms
Wind producers in the Netherlands can benefit from three incentive schemes. The main support comes from a feed-in premium. For projects requesting feed-in before 2007, the MEP support gives a fixed premium for 10 years. From 2008 forward, the SDE support gives a variable premium for 15 years. In addition to the feed-in, soft loans at a 1% discount and an investment subsidy (EIA) as a tax deduction for 44% of the investment costs to a maximum of €600/kW ($834/kW) for onshore projects are available.

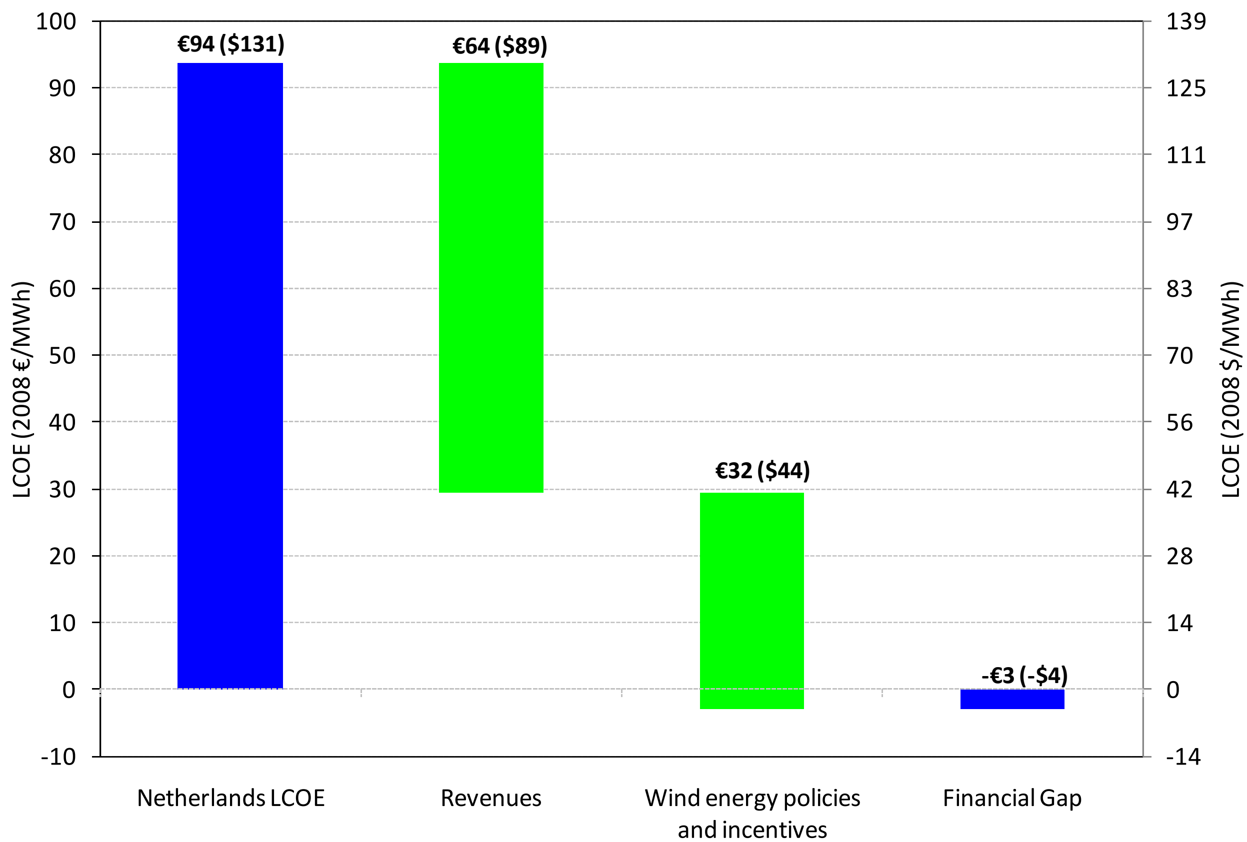


Figure 4-3. Wind energy revenue and policy incentives in the Netherlands[28]

[28] Data labels are rounded to the nearest whole numbers. Therefore, the sum of the revenues, wind energy policies and incentives, and the financial gap may differ slightly from the country LCOE.

Financial Gap

The financial gap in the Netherlands for projects that started in 2007 (see Table 4-6) was negative, amounting to about -€36/MWh (-$50/MWh). This was caused by a design flaw in the previous MEP feed-in scheme. The subsidy was based on expectations of low electricity prices (€2 to €3 /MWh) ($3 to $/MWh). As the electricity prices rose to €6-€8 /MWh ($8-11/MWh), wind projects became quite lucrative, at least as long as the electricity prices remained high. For projects that started in 2008 on the successor SDE feed-in scheme, the flaw was removed. The financial gap is slightly negative at -€3/MWh (-$4/MWh). Note that the range of production costs between the various projects is far greater than -€3 or more euros. So the negative value of -€3/MWh ($4/MWh) is not significantly below zero.

Wind offshore had a positive financial gap remaining of €5/MWh ($7/MWh). Although this is not based on first-hand financial information, it is clear that the Prinses Amalia wind farm did encounter difficulties in reaching a financial close.

Summary

The Netherlands has ambitious targets for onshore and offshore wind energy, both for the near future and for 2020. The current SDE feed-in scheme is the most important tool in realizing this. From the analysis in section 3, it follows that the financial gap in the case of the Netherlands is not significant. The subsidized electricity production is limited to 2,200 full load hours. Although this number is in line with the Dutch wind regime, there is limited incentive to produce more than 2,200 hours. The lower investment costs might be a result of this. O&M costs are relatively high due to the land cost component.

Table 4-6. Summary of results for the Netherlands[29]

		Onshore 2007	Onshore 2008	Offshore 2007	Offshore 2008
Levelized cost of energy	€/MWh ($/MWh)	91 (126)	94 (131)	166 (231)	N/A
Total revenue and wind energy policies and incentives	€/MWh ($/MWh)	127 (177)	96 (133)	161(224)	N/A
Financial gap for developer	€/MWh ($/MWh)	-36 (-50)	-3 (-4)	5 (7)	N/A

[29] As previously noted, data labels are rounded to the nearest whole numbers. Therefore, the sum of the revenues, wind energy policies and incentives, and the financial gap may differ slightly from the country LCOE.

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Chapter 5: Spain

Overview of Wind Industry in Spain

The following chapter describes the evolution of wind energy in Spain as well as the foreseen 2020 and 2030 targets, based on certain EU objectives and to reduce CO_2 emissions. The present regulatory framework is also presented, even if there are now negotiations to review some of its key elements to reduce the impact of the cost of the premiums in the retail tariffs.

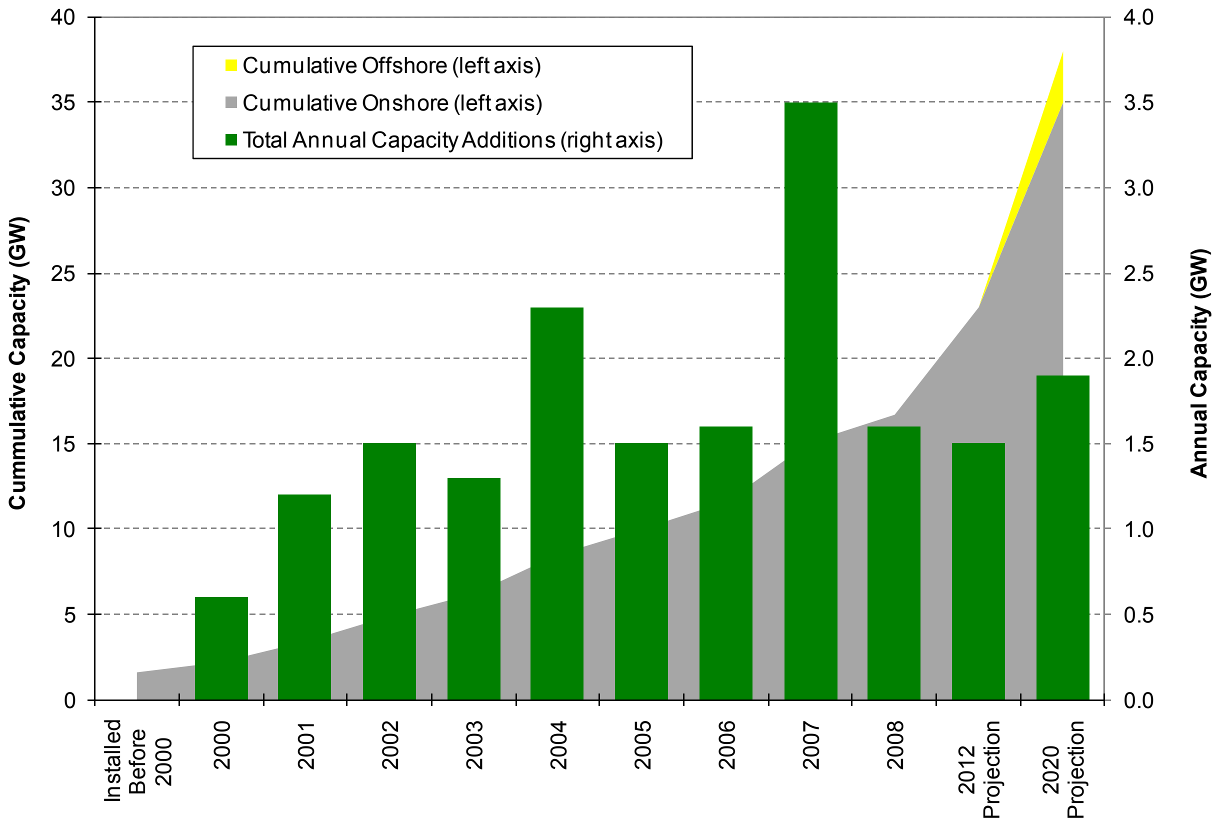
Additionally the Levelized Cost of Energy (LCOE) for a typical wind farm in the Spanish market in 2008 is also explained and the assumptions are compared with the cost of wind energy in other countries.

Capacity, Energy Production, Near-Term Targets

At the end of 2009, wind energy accounts for the third largest power generation source of the Spanish power system, reaching 19,149 MW at year-end. Wind energy development started in Spain in the mid nineties, and since 2001, the average of new wind power capacity has been of about 1,800 MW per year. The strong growth in 2004 and 2007 can be explained by the regulatory changes that were introduced (Royal Decree 436/2004 and Royal Decree 661/2007) in those two years, which led to new projects being initiated to take advantage of the existing regulation.

Wind energy production represented about 14% of the total Spanish electricity demand in 2009.

Figure 5-1 provides historical cumulative and annual wind energy installations in Spain through the year 2008, which is the focus of the cross country comparisons. The wind energy capacity projections in 2012 and 2020 are from the National Renewable Energy Action Plans (NREAP) of the European Member States (European Commission 2010). The projection in 2020 is addressed to accomplish the EU objective of achieving 20% of the demand of energy with renewable energies.



Source: Spanish Wind Energy Association (AEE) and European Commission 2010

Figure 5-1. Cumulative and annual wind installations in Spain

Table 5-1 presents historical and projected cumulative wind energy installed in Spain and Table 5-2 presents annual wind installations. It is important to indicate that in 2009, the government decided to establish a quota to limit the MWs to be installed every year between 2010 and 2012. It has also been announced that future legislation will incorporate a similar scheme, which has as its main goal to reduce the weight of the premiums in the retail tariffs (for all renewable energy and cogeneration the total amount was 6.000 MW, 25% of the total electricity turnover, especially costly in a situation of economic crisis).

The main obstacle for offshore wind in Spain is the lack of a continental platform, so the depth of sea waters is 50m near the coast. Therefore, offshore wind requires important and expensive foundations, which will limit the feasibility of these projects. Furthermore, the Common Connection Points have a limited access capacity because there are some bottlenecks from electricity generated by the Combined Cycles installed close to the regasification hubs.

Table 5-1. Cumulative GW installed in Spain

	Installed Before 2000	2000	2001	2002	2003	2004	2005	2006	2007	2008	Projection 2012	Projection 2020
Onshore	1.6	2.2	3.4	4.9	6.2	8.5	10.0	11.6	15.1	16.7	23	35
Offshore	0	0	0	0	0	0	0	0	0	0	0	3

Source: Spanish Wind Energy Association (AEE) and European Commission 2010

Table 5-2 shows historical and projected annual capacity additions in Spain.

Table 5-2. Annual GW installed in Spain

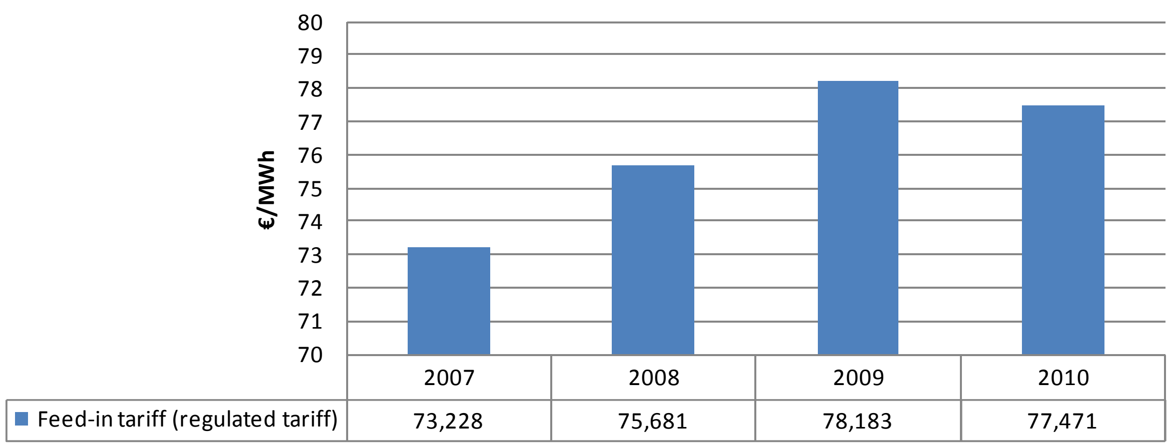
	Installed Before 2000	2000	2001	2002	2003	2004	2005	2006	2007	2008	Projection 2012	Projection 2020
Onshore	1.6	0.6	1.2	1.5	1.3	2.3	1.5	1.6	3.5	1.6	1.5	1.4
Offshore	0	0	0	0	0	0	0	0	0	0	0	0.5

Source: Spanish Wind Energy Association (AEE) and European Commission 2010

Revenue and Policy Incentives

To receive the benefits foreseen in the law, the wind projects have to be typified as Special Regime (similar to the American Qualifying facilities) because they have priority of access to the grid (the electricity surplus has to be purchased by the retailers) and the price is regulated. As stated in the Royal Decree 661/2007, there are two pay schemes for wind power: the regulated tariff scheme and the market mechanism.

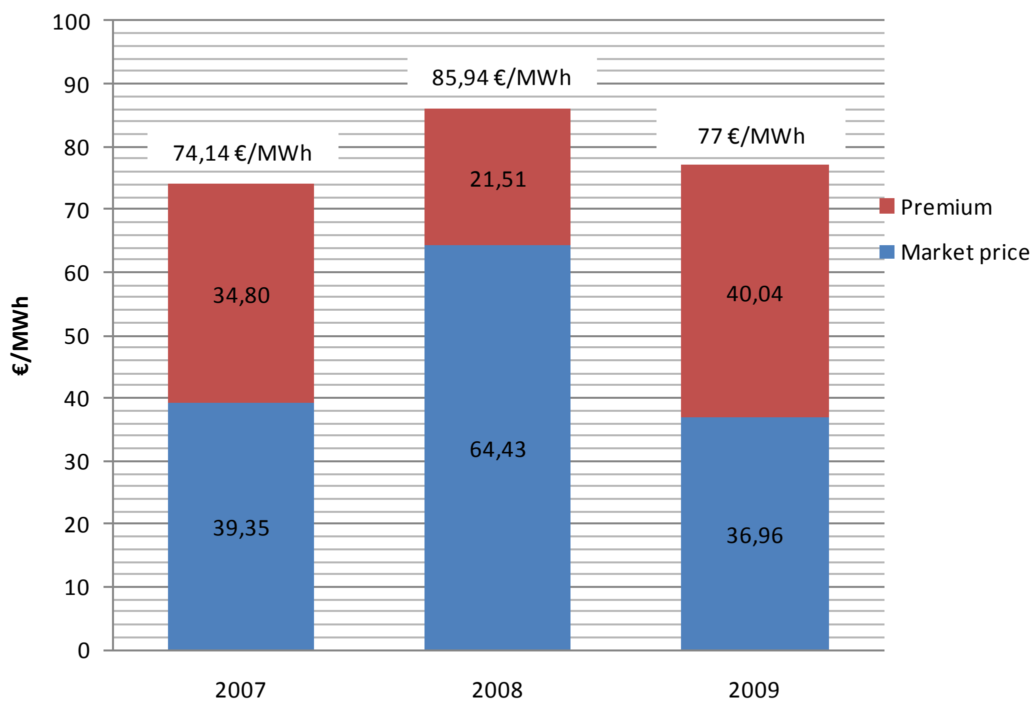
- The regulated tariff scheme is a mandated feed-in price for wind generation along the period selected by the wind farms owner (values in Figure 5-2).



Source: Spanish Wind Energy Association (AEE)

Figure 5-2. Evolution of the regulated tariff

- The market mechanism, whereby the final price is the combination of the wholesale electrical market price, according to the hourly marginal price plus a production incentive, is also called premium. So the tariff received by the wind producer will depend on the pool price, with a floor if that price is very low and a roof if the price is over a minimum. Figure 5-3 presents the reference values of the regulated tariff, floor, and roof.



Source: Spanish Wind Energy Association (AEE)

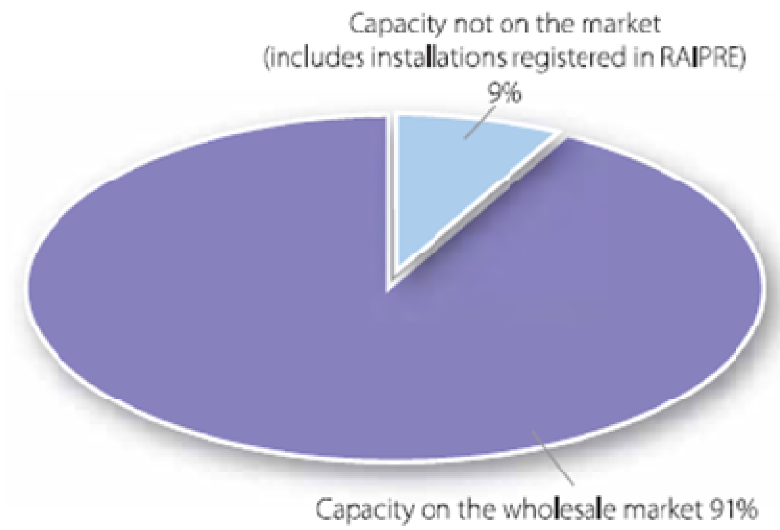
Figure 5-3. Final retribution in the market option (market price plus premium)

Wind producers present a production program for day-ahead markets, and therefore, they use predictions to reduce the deviations between that program and the real production. Furthermore, the projects are grouped to reduce the errors thanks to the compensation between wind farms settled in different basins. This system allows an optimization of the use of ancillary systems and balancing, and the cost is partially paid by the wind producers (around €1.5/MWh ($2.05/MWh) in 2008).

The RD 661/2007 updated the aforementioned values based on the Consumer Price Index, with a correction factor of 25 basis points, up to December 31, 2012, and 50 basis points thereafter.

Figure 5-3 shows the varying feed-in tariff rates since RD 661/2007 came into force. In 2007, RD 661/2007 set a feed-in tariff to be renewed in line with the Consumer Price Index, with a correction factor of 25 basis points, up to December 31, 2012, and 50 basis points thereafter. In 2010, the update was negative and the values are lower than the previous year because the CPI was near to zero.

According to the Red Eléctrica de España (REE), the national Transmission System Operator (TSO), 9% of capacity was operated through the feed-in tariff option; therefore, it is not affected by the variation of the wholesale electrical market price (Figure 5-4).

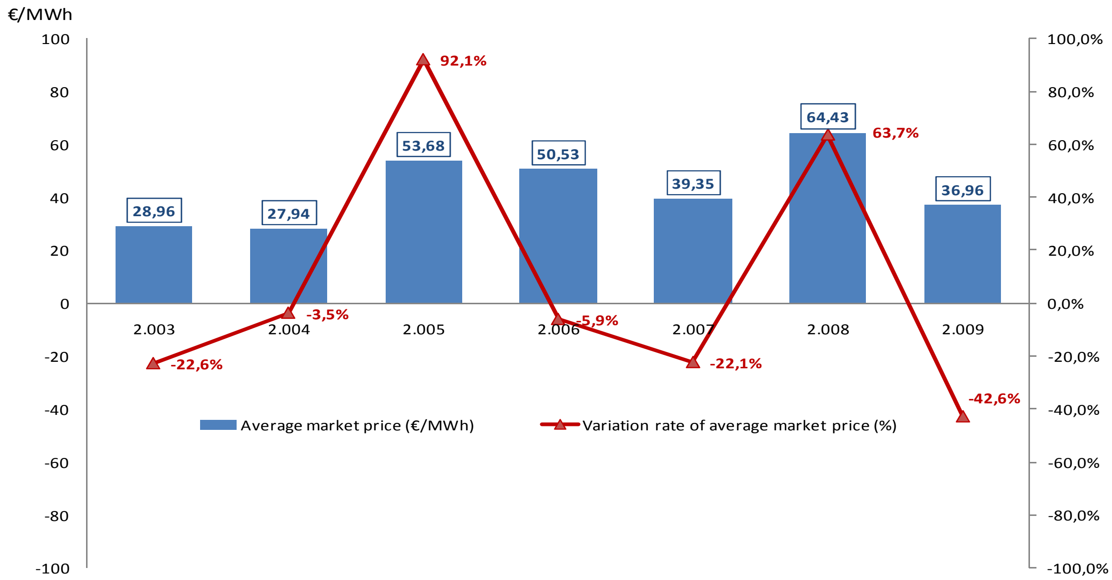


Source: Spanish TSO (REE)

Figure 5-4. Wind capacity on the wholesale market, 2008

As the greatest part of the wind generation is sold directly on the wholesale market, remunerations depend largely on that pool price, which is influenced by the natural gas prices, the hydro conditions, and the CO_2 prices in the international markets. In this sense, in 2008, the average daily pool price was €64.43/MWh ($89.56/MWh), the highest registered to date, 64% higher than the 2007 price of €39.35/MWh ($54.70/MWh).

Wind power purchase prices on the market are illustrated in Figure 5-3, and the wholesale electricity prices presented in Figure 5-5. As mentioned earlier, in the case of RD 661/2007, that price is the sum of the price on the daily wholesale electricity market plus the premium, within the band of a floor and cap.



Sources: OMEL and Spanish Wind Energy Association (AEE)

Figure 5-5. Year average of the daily electricity pool price and variation rate, 2003 – 2009

Typical Wind Energy Project in Spain in 2008

The following section describes Spanish wind energy project characteristics in 2008, which will be used to compare the different models of wind energy development among participating countries.

Onshore

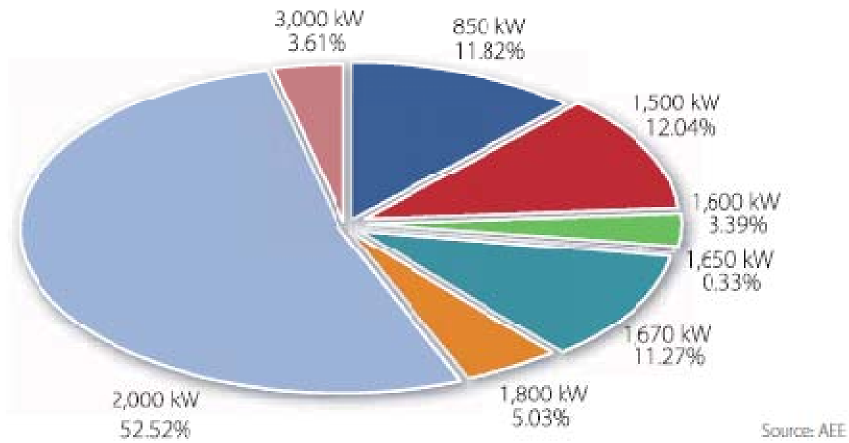
Project Features

To have access to the Special Regime system, the Spanish onshore wind farm size should not exceed 50 MW. The average size of installed wind parks is around 25 MW and for the calculation, the wind farm is assumed to be 30 MW of installed capacity for both 2007 and 2008.

The nominal operational hours vary from 1,700 to 2,350 hours per year at nominal power (the national average for 2008 was 2,085 hours) and the reference value for the project was 2,200 hours for 2007 and 2,150 hours for 2008.

In all the financial models used in Spain, the project life cycle is 20 years, even if there is not experience of wind farms within this operational span. The value finally selected is of 20 years for both 2007 and 2008.

The average size of the wind turbines installed in 2008 was 1,985 kW; this represents a slight increase when compared with the 1,621 kW of 2007. In the model, we will consider a 2,000 kW wind turbine, which means 15 wind turbines of 2 MW for the wind farm.



Source: Spanish Wind Energy Association (AEE)

Figure 5-6. Size breakdown of wind turbines installed over 2008

Investment Costs

The increase of the total investment in the last years has been mainly due to the installation of bigger wind turbine generator systems (WTGS), Class III and IV, the connection to high voltage, and various taxes not initially foreseen.

Nevertheless, in the last years, the cost of turbines has been reduced due to the decrease of raw material prices, and the decrease in turbine demand by the financial crisis and regulatory changes.

Of the total investment in a wind farm, the cost of the turbine is about 70-73% of the total. This cost is closely linked to the price of raw materials and to the complexity of the required technology conditioned to the current grid codes.

For projects installed in 2007, the investment cost is estimated at €1,233/kW ($1,714/kW) and €1,250/kW ($1,738/kW) in 2008.

Operations and Maintenance Costs

The operations and maintenance costs also rose by the curtailments, the increase of electric self-consumption tariffs, and the greater technical complexity of the installations.

The operation and maintenance costs are estimated to €19.10/MWh ($26.55/MWh) in 2007 and €19.63/MWh ($27.29/MWh) in 2008 (100% variable costs). These costs are linked to several factors including: variation of the wage level, availability of substitute components and of the required qualified personnel, and mechanical devices.

The nominal hours will be reduced since the best sites have been used in spite of the increase of the WTG´s size.

Financing Costs

Wind energy projects development in Spain have been historically financed through project finance schemes due to the financial capacity of banks operating in Spain as well as the stable legal framework. Nevertheless, the situation has changed in the last two years by the lack of liquidity of the financing system and some collateral guarantees are also requested.

The financing costs are established, for year 2007 to 10% of return on equity and 7% of return on debt. The equity share is 20% and debt share 80% for 2007 and 2008. For the year 2008, the values are 10% for return on equity and 7% for the return on debt.

Revenue and Policy Incentives

Revenues from the sale of energy to the market was €39.4/MWh ($54.8/MWh) in 2007 and €64.4/MWh ($89.5/MWh) in 2008. These revenues are in addition to the Feed-in Tariff premium evaluated at €34.8/MWh ($48.3/MWh) in 2007 and €21.5/MWh ($29.9/MWh) in 2008. The Feed-in Tariff policy period is fixed at 20 years for both cases.

Source of Data

The data we presented here came from a study realized by the Spanish Wind Energy Association (AEE) and Intermoney.

Offshore

Project Features

The Spanish offshore has been divided into 62 areas in which the development of wind power is regulated. These areas will be opened to tender. Apart from some experimental initiatives, the projected wind farm sizes are around 1000 MW.

Investment Costs

No offshore data.

Operations and Maintenance Costs

No offshore data.

Financing Costs

No offshore data.

Revenue and Policy Incentives

No offshore data.

Source of Data

No offshore data.

Model Input Assumptions

Tables 5-2 through 5-5 provide the modeling assumptions used in the levelized cost of energy analysis that follows. All cost assumptions are representative of wind projects in 2007 and 2008, and are expressed in 2008 Euros.

Table 5-3. Wind energy project features in Spain

		Onshore 2007	Onshore 2008	Offshore 2007	Offshore 2008
Unit size	MW	30	30	N/A	N/A
Number of turbines	N	15	15	N/A	N/A
Production	full load hours	2,200	2,150	N/A	N/A
Economic life	years	20	20	N/A	N/A
Investment costs	€/kW ($/kW)	1,233 (1,714)	1,250 (1,738)	N/A	N/A
O&M costs fixed	€/kW ($/kW)	0	0	N/A	N/A
O&M costs variable	€/MWh ($/MWh)	19.1(26.6)	19.6(27.2)	N/A	N/A
Decommission costs	€/MWh ($/MWh)	0	0	N/A	N/A

Table 5-4. Wind energy financing terms in Spain

		Onshore	Onshore	Offshore	Offshore
		2007	2008	2007	2008
Return on equity	%	9	10	N/A	N/A
Return on debt	%	6	7	N/A	N/A
Equity share	%	20	20	N/A	N/A
Debt share	%	80	80	N/A	N/A
Loan duration	years	15	15	N/A	N/A
Corporate tax rate	%	30	30	N/A	N/A
FX rate	$US/€	1.39	1.39	N/A	N/A

Table 5-5. Wind energy policy and revenue incentives in Spain

		Onshore 2007	Onshore 2008	Offshore 2007	Offshore 2008
Market price electricity	€/MWh ($/MWh)	53 (74)	54 (75)	N/A	N/A
FIT revenue	€/MWh ($/MWh)	34 (47)	35 (49)	N/A	N/A
FIT policy period	Years	20	20	N/A	N/A
Upfront tax-based subsidy before tax	%	0	0	N/A	N/A
Production-based before tax credits	€/MWh ($/MWh)	0	0	N/A	N/A
Production-based before tax credit policy period	Years	-	-	N/A	N/A
Depreciation period	Years	20	20	N/A	N/A
Reactive power bonus	€/MWh ($/MWh)	3.6 (5.1)	3.7 (5.2)	N/A	N/A
Low voltage ride through bonus	€/MWh ($/MWh)	0	0	N/A	N/A
Market Certificates	€/MWh ($/MWh)	-	-	N/A	N/A

The 2008 LCOE in Spain is compared to the Reference Case in Figure 5-7, showing the differences between the two. The Spain LCOE is €15/MWh ($21/MWh) higher than the Reference Case LCOE.

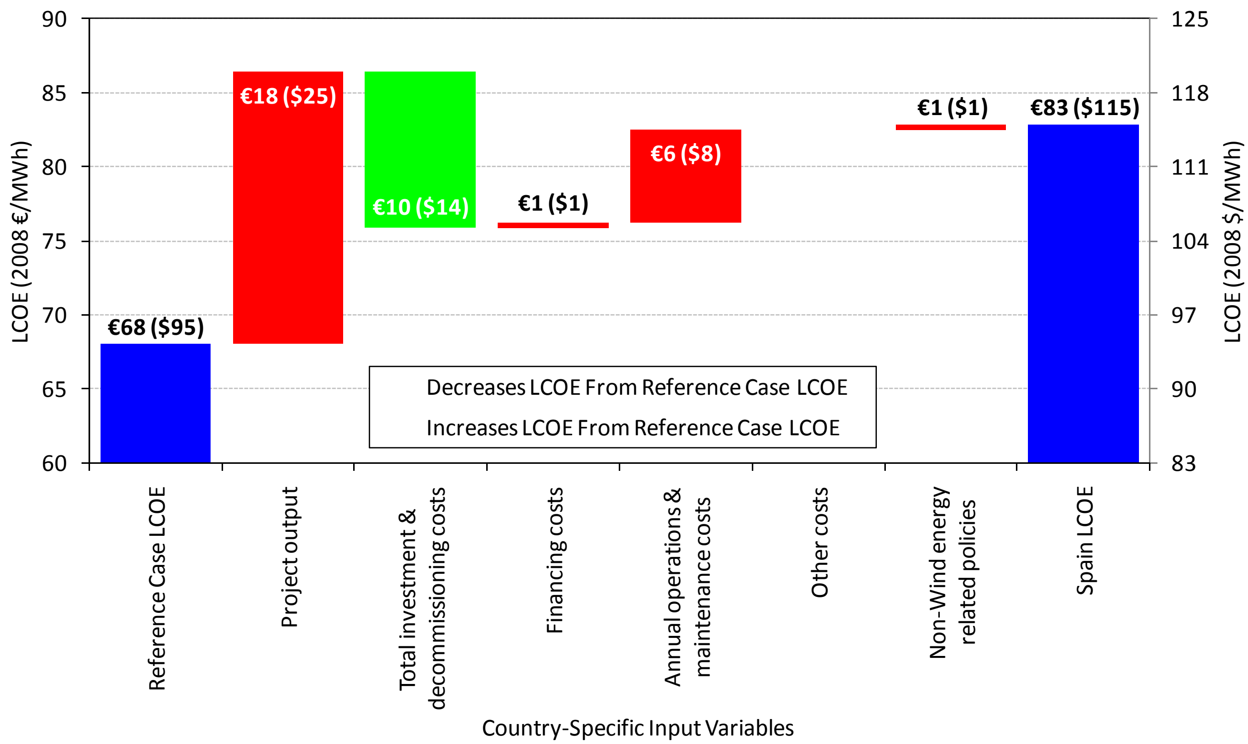


Figure 5-7. Wind energy costs in Spain and the Reference Case in 2008[30]

Project Output

A wind energy project in Spain has less capacity factor on average than the Reference Case. Due to the wind conditions, lower full load hours in Spain increase the Spain LCOE to the Reference Case LCOE by €18/MWh ($25/MWh). An average of 2,150 full load hours is expected in the Spanish case compared with 2,628 hours for the Reference Case.

The full load hours are the most important variable regarding the differences between the Spain LCOE and the Reference Case LCOE. In addition to the wind conditions, the operation and maintenance costs also are over the Reference Case, and the land rents and the returns requested by regions and municipalities also are included.

The third element explaining the higher LCOE is the financing costs, which increase the WACC of the projects and finally the ROI requested to each specific investment.

[30] Data labels are rounded to the nearest whole numbers. Therefore, the sum of input variables may differ slightly from the total Reference Case – Country LCOE differential (due to rounding).

Investment Costs

The total investment cost in Spain is about €1,250/kW ($1,738/kW) - lower than the Reference Case by about €200/kW ($278/kW). Due to the lower investment cost in Spain, the LCOE is €10/MWh ($14/MWh) lower.

Decommissioning costs, which include the dismantling of wind energy generation equipment when the economic life of the wind farm is finalized, are about 3% of the total investment cost.

Financing Costs

Regarding the financial conditions, in the Spanish case, the value of return on equity and return on debt are higher than the same values of the Reference Case.

Operations and Maintenance Costs

In Spain, the operation and maintenance costs are higher than the Reference Case. Total operations and maintenance costs in Spain include all kinds of variable costs including taxes, rents, and administrative expenses. In the next years, the operation and maintenance costs will also rise by the curtailments, the increase of electric self-consumption tariffs, and the greater technical complexity of the installations.

On average, the operation and maintenance costs in Spain are about €19.6/MWh ($27.2/MWh), almost €7/MWh ($10/MWh) higher than the Reference Case.

Revenues and Wind Energy Policies and Incentives

As mentioned earlier, in Spain there are two pay schemes: a feed-in tariff scheme (a fixed price for the wind generation) and a market scheme (the market price plus a premium for the wind production). In 2008, almost 91% of the wind production was selling in the market option, because it allows developers to obtain higher revenues.

Figure 5-8 compares the revenue variables (electricity price) to the wind energy policies and incentives variables (premium in the market scheme in Spain).

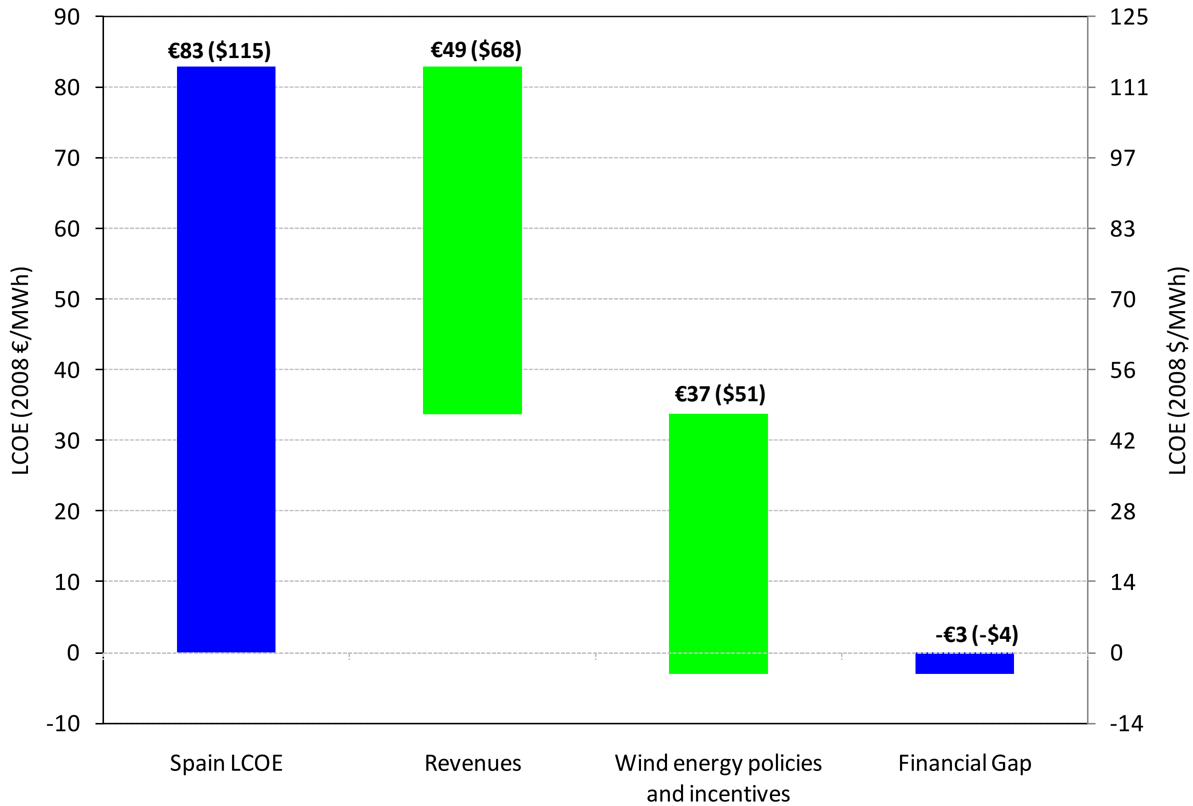


Figure 5-8. Revenues and wind energy policies and incentives in 2008[31]

Financial Gap

The financial gap in the Spanish modeling analysis is approximated at -€3(-$4). This suggests that on average, a wind project developer in Spain receives sufficient cash flow from revenue and wind energy policies and incentives to meet the financial requirements to develop the project.

Summary of Wind Projects in Spain

Table 5-6. Summary of results for Spain[32]

		Onshore 2007	Onshore 2008	Offshore 2007	Offshore 2008
Levelized cost of energy	€/MWh ($/MWh)	76(106)	83(115)	N/A	N/A
Total revenues and wind energy polices and incentives	€/MWh ($/MWh)	87(121)	86(120)	N/A	N/A
Financial gap for developer	€/MWh ($/MWh)	-11(15)	-3(-4)	N/A	N/A

[31] Data labels are rounded to the nearest whole numbers. Therefore, the sum of the revenues, wind energy policies and incentives, and the financial gap may differ slightly from the country LCOE.
[32] As previously mentioned, data labels are rounded to the nearest whole numbers. Therefore, the sum of the revenues, wind energy policies and incentives, and the financial gap may differ slightly from the country LCOE.

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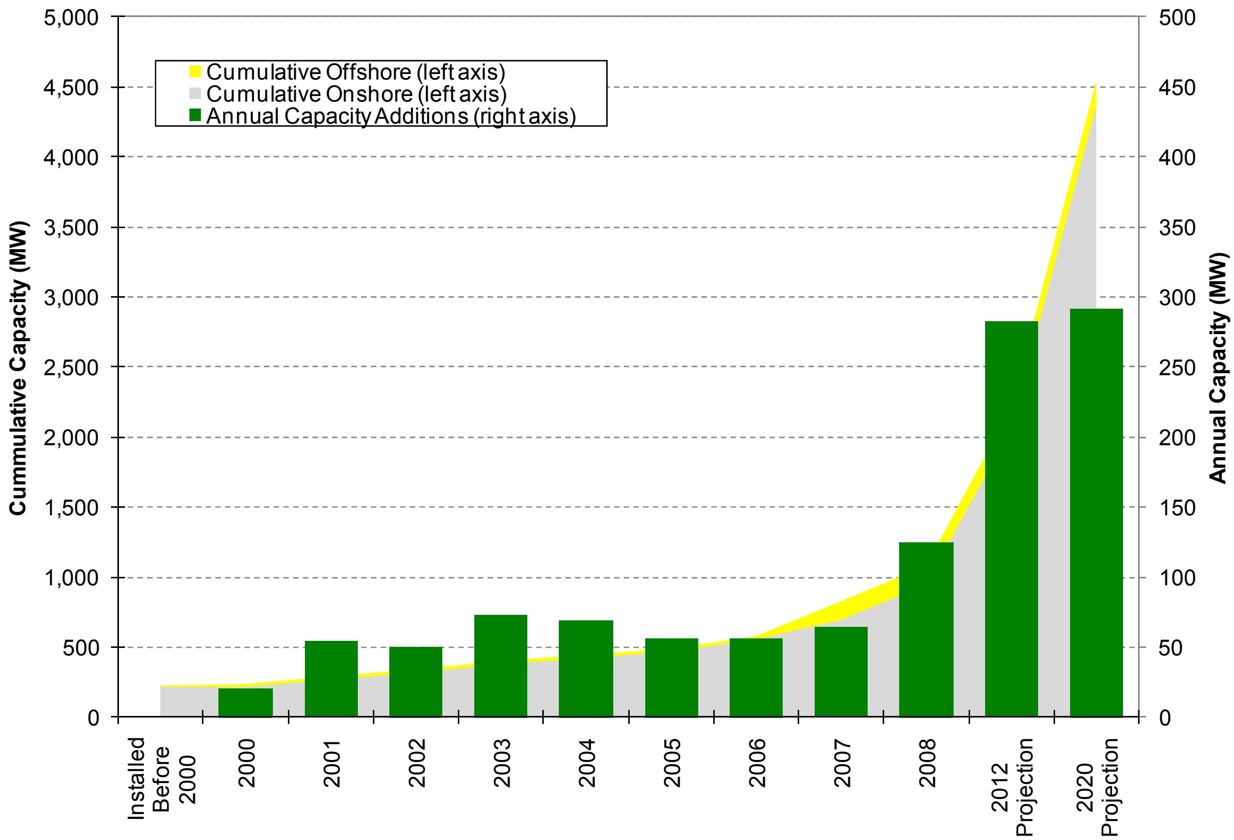
Chapter 6: Sweden

Overview of Wind Industry in Sweden

The following chapter describes onshore and offshore wind energy project and cost characteristics in Sweden, and the assumptions used in modeling the levelized cost of energy (LCOE) for onshore wind technologies in 2008.

Capacity, Energy Production, Near-Term Targets

Onshore wind energy capacity in Sweden expanded from approximately 474 MW of cumulative installations in 2004 to 937 MW by year-end 2008 (Figure 6-1). A 110 MW offshore wind farm in Southern Sweden was installed in 2007 and "near shore" lake-based projects have also been developed. The wind energy capacity projections in 2012 and 2020 are from the National Renewable Energy Action Plans (NREAP) of the European Member States (European Commission 2010).



Source: Vinkraft Statistik 2009, Vindkraft Statistik 2007, and European Commission 2010

Figure 6-1. Cumulative and annual wind installations in Sweden

Table 6-1 presents historical and projected *cumulative* wind energy installed in the U.S.

Table 6-1. Cumulative MW installed in Sweden

	Installed Before 2000	2000	2001	2002	2003	2004	2005	2006	2007	2008	Projection 2012	Projection 2020
Onshore	220	220	272	322	381	429	470	560	698	951	2,065	4,365
Offshore	10	20	23	23	23	23	23	23	133	133	150	182

Source: Vinkraft Statistik 2009, Vindkraft Statistik 2007, and European Commission 2010

Table 6-2 shows historical and projected *annual* capacity additions.

Table 6-2. Annual MW installed in Sweden

	Installed Before 2000	2000	2001	2002	2003	2004	2005	2006	2007	2008	Projection 2012	Projection 2020
Onshore	-	0.5	51	50	59	48	41	90	138	253	278	288
Offshore	-	10	2.5	0	0	0	0	0	110	0	4	4

Source: Vinkraft Statistik 2009, Vindkraft Statistik 2007, and European Commission 2010

Revenue and Policy Incentives

In Sweden, a tradable green certificate system (TGC) is in place to support renewable electricity production. The scheme provides support for a period of 15 years. The goal is to increase production from renewable energy sources to 17 TWh by the year 2016. The system is currently under revision to adapt to the higher goal of 25 TWh renewable electricity production by 2020. In addition, negotiations between Sweden and Norway are currently underway to establish a common system for both countries.

Up to the year 2008, a feed-in tariff, also known as an "environmental bonus," existed for onshore wind energy in parallel with the electricity certificates system. For offshore wind energy, the "environmental bonus" was in place up to 2009. There also has been a support scheme for pilot projects in place since 2003. For the period 2008-2012, € 37.1 million ($51.6 million) is assigned to projects that are deemed interesting such as offshore wind, cold climate, or forest-based wind power generation.

In the autumn of 2006, rules for the environmental impact analysis and the admission process for new wind power projects were simplified. Under the simplified process, wind parks up to 25 MW only need to notify the municipality.

A national network[33] for wind use has been created as an initiative of the Swedish government, to spread information about the use of wind resources. The purpose of the network is to facilitate the development of wind power in Sweden by strengthening the country's knowledge on planning and admission processes; labor, business development, and operations and maintenance of wind power.

[33] See http://www.natverketforvindbruk.se/

In addition, wind power coordinators are employed to facilitate the interaction between wind power producers, authorities, and other actors at the local, regional, and national level.

Typical Wind Energy Project Characteristics in Sweden

Onshore

Project Features

In Sweden, full load hours for an onshore project were reported to range from 2,600-3,050. However, wind maps of Sweden typically show lower full load hours than the numbers reported by wind project developers. Therefore, the wind hours in the final submission of the Swedish project are on the low end of the reported range, resulting in 2,600 hours used in the calculations.

Investment Costs

The Swedish onshore project was defined as representative of the average cost and energy production of onshore projects installed in 2008. Capital costs range between €1,217/kW to €1,915/kW ($1,692/kW to $2,662/kW). For the modeling analysis, €1,591/kW ($2,212/kW) was assumed.

Operations and Maintenance Costs

The average fixed costs for operations and maintenance are estimated at €0.004 /kW ($0.006/kW) and the variable costs are estimated at approximately €11/MWh ($15/MWh). However, the variable O&M costs can range between €7/MWh to €24/MWh ($10/MWh to $33/MWh). The spread for the O&M cost in the applications of the pilot projects is quite large and varies among developers.

Financing Costs

As shown in Table 6-5, a debt interest rate of 5% was assumed in the modeling analysis since this number is commonly reported by investors. However, an analysis of accounting statements of the companies investing in wind power reveals a much higher cost debt of up to 20% or more. It is possible that the assumed 5% debt interest rate combined with the required return on equity of 12%, derived from company analysis in Sweden, may lead to an underestimation of the cost of wind power.

Revenue and Policy Incentives

Wind energy projects receive two revenue streams: one from selling electricity to the market through long term contracts and the other from the tradable green certificate system in place. Both revenue streams are highly uncertain. Until 2008, the feed-in tariff bonus was also in place, with onshore wind receiving a small premium of €2/MWh ($3/MWh).

Source of Data

The data for the LCOE calculations comes from several sources, including data supplied from applications for the pilot support scheme mentioned above, as well as data compiled by the Swedish Energy Agency for internal users. Data for decommissioning cost come from Svensk Vindenergi (2009). Statistics on the development of wind power in Sweden come from two publications produced annually by the Swedish Energy Agency report ES 2010:3 Vindkraft statistik 2009 (Wind power statistics 2009) and Vindkraft Statistik 2008. Wind hours for 2008 are taken from the electricity certificates system. In addition, some confidential data, such as the financing terms, were obtained from wind power developers. Accounting data was used to get a clearer picture of the relevant discount rates. Expert opinions cited in the business press in connection with the planned stock market introduction of O2 and Arise complemented the picture.

Offshore

The largest Swedish offshore project in place as of 2008 was Lillgrunden with 110 MW. The Lillgrunden project was taken over by Vattenfall in 2004, and built and connected to the grid in 2007. Lillgrunden consists of 48 Siemens 2.3 MW MKII turbines. However, thirteen wind turbines installed at Lillgrunden were connected to the grid before 2004. Sweden's newest project is Gässlingegrund with 10 turbines of 3 MW each. This is a "near shore" project with foundations at between 7-13 meters in Lake Vänern.

Table 6-3. Lillgrunden example

Lillgrunden Data	
Total height:	115 m above MSL
Rotor diameter:	92,4 m
Swept area:	6734 m2
Power regulation:	Variable pitch and speed
Rotor speed:	6-16 rpm
Tip speed: max	280 km/h
Rotor weight	60 t
Nacelle weight	82 t
Tower weight:	110 t
Est. annual production:	6.875.000 kWh
Capacity factor:	35%
Average wind speed:	8.5 m/s

Table 6-4. Wind energy project features in Sweden

		Onshore 2007	Onshore 2008	Offshore 2007	Offshore 2008
Unit size	MW	-	2.35	N/A	N/A
Number of turbines	N	-	41	N/A	N/A
Production	full load hours	-	2,600	N/A	N/A
Economic life	years	-	20	N/A	N/A
Investment costs	€/kW ($/kW)	-	1,591(2,212)	N/A	N/A
O&M costs fixed	€/kW ($/kW)	-	0.004 (0.006)	N/A	N/A
O&M costs variable	€/MWh ($/MWh)	-	11(15)	N/A	N/A
Decommission costs	€/kW ($/kW)	-	1.6 (2.22)	N/A	N/A
Other costs	€/MWh ($/MWh)	-	-	N/A	N/A

Table 6-5. Wind energy financing terms in Sweden

		Onshore 2007	Onshore 2008	Offshore 2007	Offshore 2008
Return on debt	%		5	N/A	N/A
Return on equity	%		12	N/A	N/A
Debt share	%		87	N/A	N/A
Equity share	%		13	N/A	N/A
WACC	%		4.7	N/A	N/A
Loan duration	years		20	N/A	N/A
Corporate tax rate	%		28	N/A	N/A
FX rate	(SEK/€)		9.42	N/A	N/A
FX rate	US$/€		1.39		

Table 6-6. Wind energy policy and revenue incentives in Sweden

		Onshore 2007	**Onshore 2008**	**Offshore 2007**	**Offshore 2008**
Market price electricity	€/MWh ($/MWh)		50 (70)	N/A	N/A
Market price certificates	€/MWh ($/MWh)		25 (35)	N/A	N/A
FIT revenue	€/MWh ($/MWh)		2 (3)	N/A	N/A
FIT policy period	years		1	N/A	N/A
Upfront tax-based subsidy before tax	%		0%	N/A	N/A
Production-based before tax credits	€/kWh ($/kWh)			N/A	N/A
Production-based before tax credit policy period	years			N/A	N/A
Depreciation period	years		20	N/A	N/A
Reactive power bonus	€/MWh ($/MWh)		0	N/A	N/A
Low voltage ride through bonus	€/MWh ($/MWh)		0	N/A	N/A

Comparison of Wind Energy Costs in Sweden to the Reference Case

As shown in Figure 6-2, the Swedish LCOE is approximately €1/MWh ($1/MWh) lower than the Reference Case.

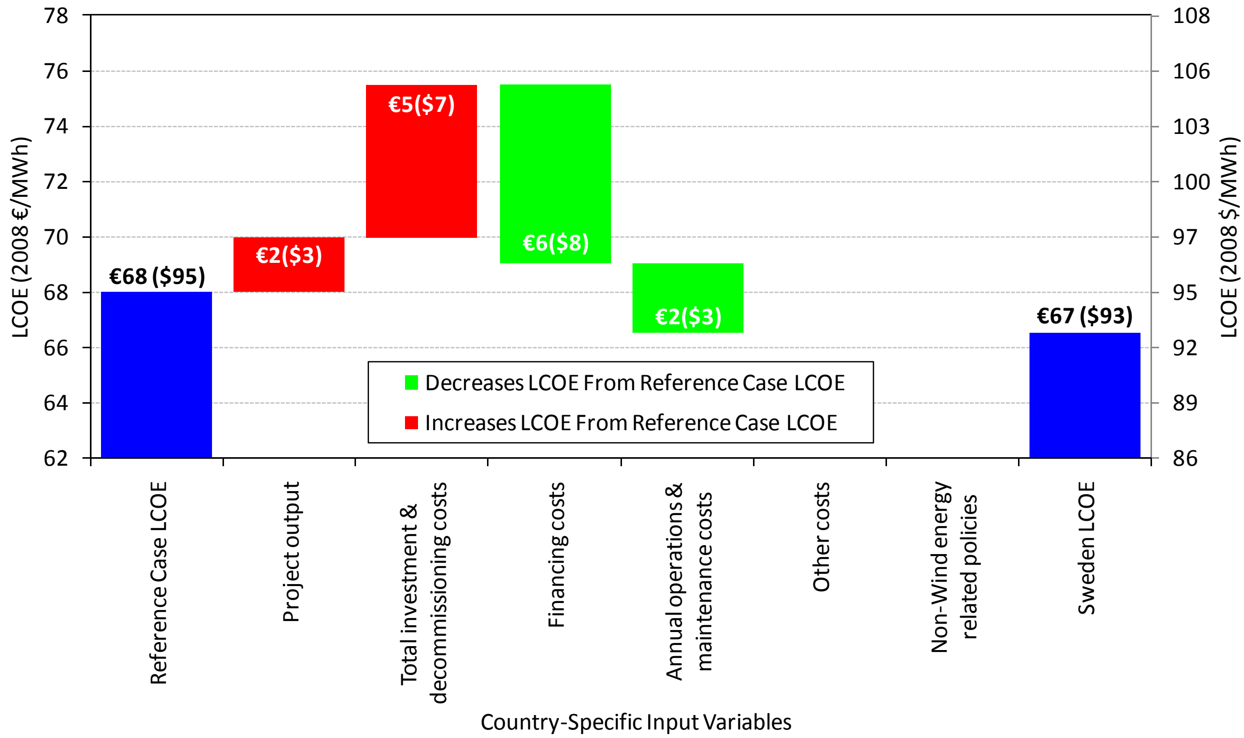


Figure 6-2. Wind energy costs in Sweden[34]

Project Output

Full load hours in Sweden are higher than in the Reference Case, which is quite reasonable given the vast amounts of land available for wind power projects in comparison to some of the European countries in the sample.

Investment Costs

Investment costs in Sweden are slightly higher than in the Reference Case due to power development, a TGC system (in place since 2001), and the existence of NordPool (for electricity trading since 1995).

Operation and Maintenance Costs

The difference in O&M costs in Sweden compared to the Reference Case is minimal and most likely due to the sample and not significant.

Financing Costs

Financing costs are lower in Sweden compared to the Reference Case. This essentially reflects a lower risk level for wind power investments in Sweden, which is reasonable given the experience gained over time with wind power development.

[34] Data labels are rounded to the nearest whole numbers. Therefore, the sum of input variables may differ slightly from the total Reference Case – Country LCOE differential (due to rounding).

Revenues and Policy Incentives

Revenues consist of three parts: 1) revenues from the sale of electricity; 2) revenues from the sale of green certificates; and 3) a small revenue stream from a FIT that ceased to exist after 2009.

As the revenue streams are market-based, they are uncertain. In the case at hand, electricity prices are assumed to be stable around €50/MWh ($70/MWh) and green certificate prices around €25/MWh ($35/MWh), though the price of green certificates rose in 2009.

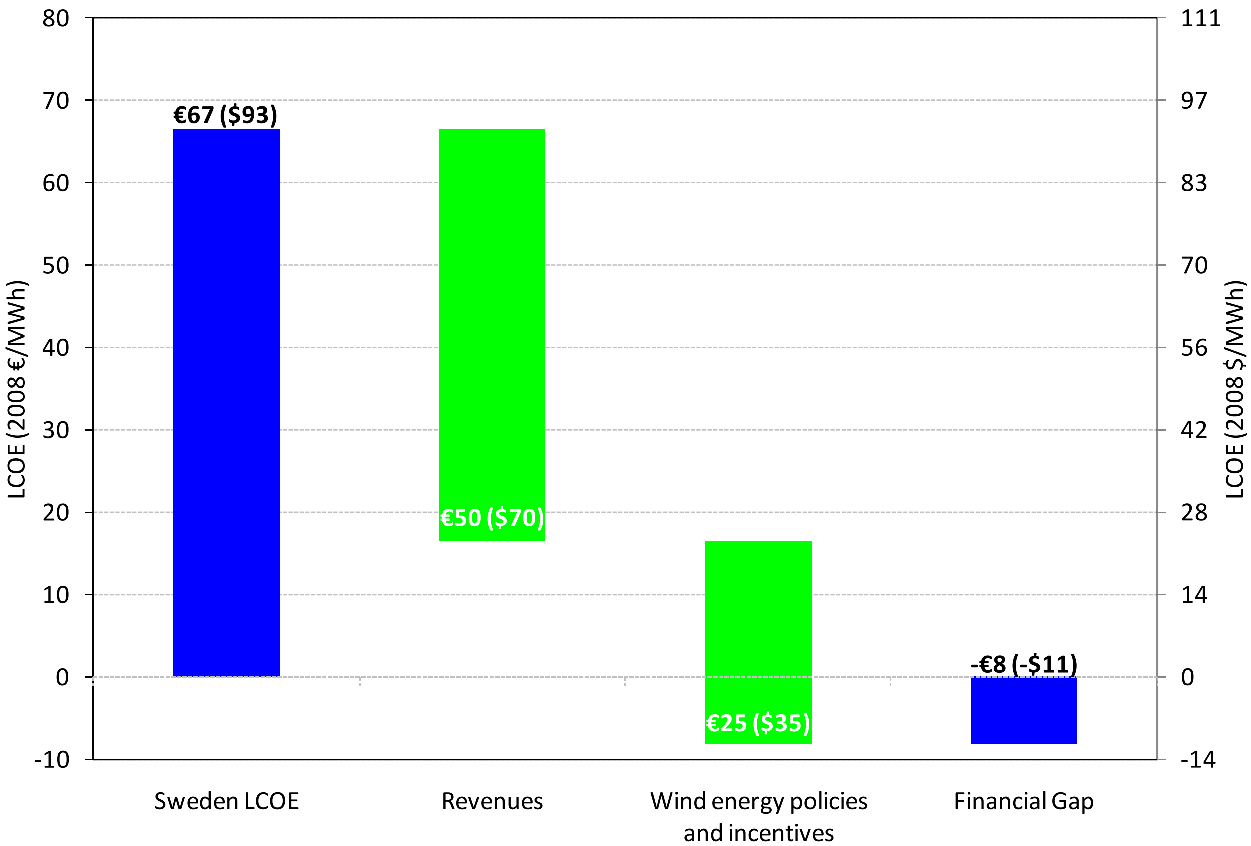


Figure 6-3. Wind energy revenue and policy incentives in Sweden[35]

[35] Data labels are rounded to the nearest whole numbers. Therefore, the sum of the revenues, wind energy policies and incentives, and the financial gap may differ slightly from the country LCOE.

Financial Gap
For the average project, the costs seem to be covered quite well by the combination of market price of electricity and the compensation from the TGC system.

Table 6-7. Summary of results for Sweden[36]

		Onshore 2007	Onshore 2008	Offshore 2007	Offshore 2008
Levelized cost of energy	€/MWh ($/MWh)	-	67 (93)	N/A	N/A
Total revenue and wind energy policies and incentives	€/MWh ($/MWh)	-	75(104)	N/A	N/A
Financial gap for developer	€/MWh ($/MWh)	-	-8 (-11)	N/A	N/A

Summary of Wind Projects in Sweden

As Table 6-7 shows, wind power projects in Sweden appear to have a relatively low weighted average cost of capital (WACC) as a result of low equity and debt costs. Projects are financed with large shares of debt financing. Loans are financed for 20 years. Although parts of these loans are probably of shorter duration, they are rolled over at the end of the lending period.

Wind power has a long history in Sweden and is growing quite rapidly. This growth is necessary to achieve the overall goal of 25 TWh from renewable energy sources by 2020.

[36] As previously mentioned, data labels are rounded to the nearest whole numbers. Therefore, the sum of the revenues, wind energy policies and incentives, and the financial gap may differ slightly from the country LCOE.

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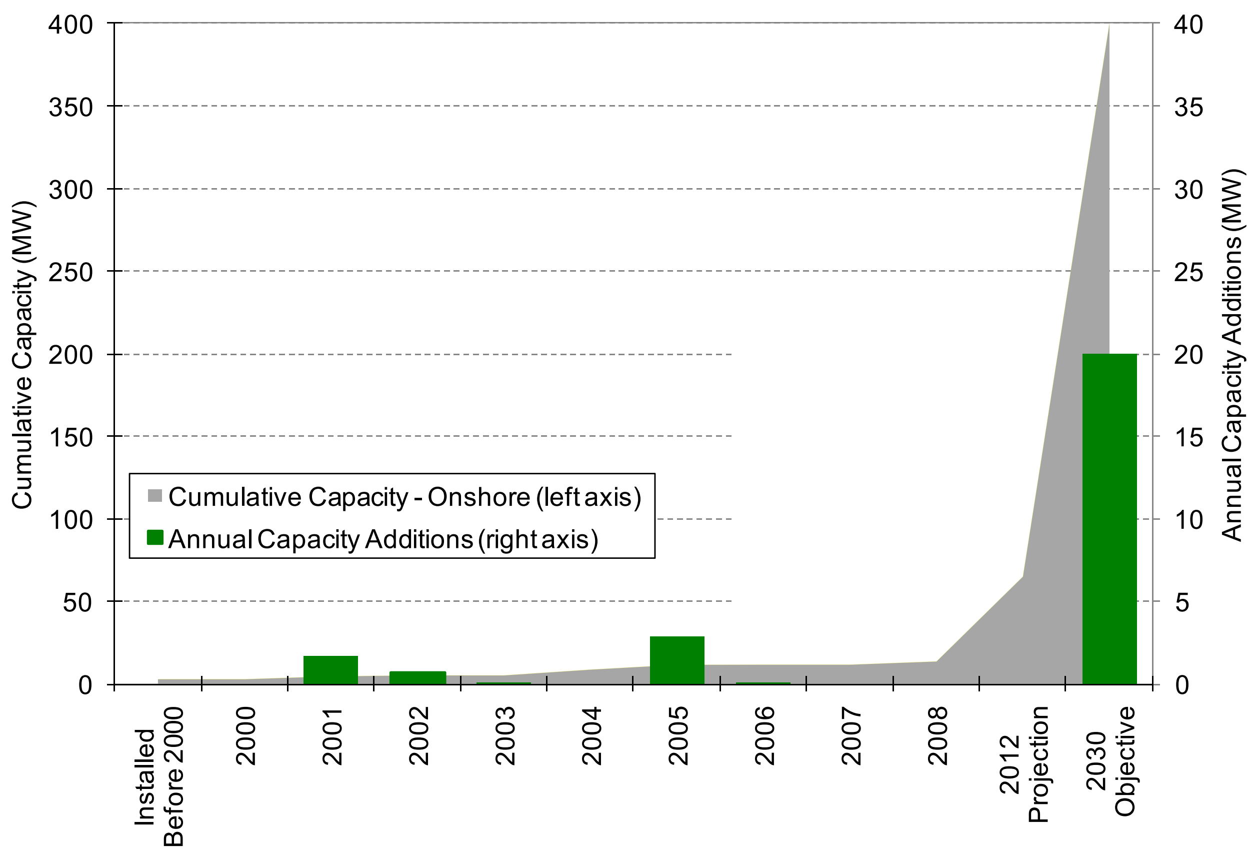
Chapter 7: Switzerland

Overview of Wind Industry in Switzerland

The following chapter describes onshore and offshore wind energy project and cost characteristics in Switzerland, specifically the assumptions used in modeling the levelized cost of energy (LCOE) for onshore wind technologies in 2008. Since Switzerland is a land-locked country, there are no offshore projects. Lake areas are presently excluded as wind energy sites for landscape protection reasons.

Capacity, Energy Production, Near-Term Targets

The installed wind capacity onshore has increased from 2 MW in 1996 to approximately 14 MW at the end of 2008. The annual wind energy production has risen from 1.8 GWh (2000) to 20.20 GWh (2008). As a comparison, the total electricity demand in 2008 amounts to 58.7 TWh. From projects which are currently in an advanced stage of planning, a projected capacity of 65 MW is expected for 2012. Federal energy policy has set an objective of 400MW capacity for 2030.



Source: wind-data.ch and Federal Office of Energy

Figure 7-1. Cumulative and annual wind installations in Switzerland

Table 7-1 presents historical and projected cumulative wind energy installed in Switzerland.

Table 7-1. Cumulative MW installed in Switzerland

	Installed Before 2000	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Projected 2012	Objective 2030
Onshore	2.8	2.8	4.51	4.55	4.56	8.66	11.6	11.6	11.6	13.6	17.6	65	400

Source: wind-data.ch and Federal Office of Energy

Table 7-2 shows historical and projected *annual* capacity additions.

Table 7-2. Annual MW installed in Switzerland

	Installed Before 2000	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Projected 2012	Objective 2030
Onshore	2.8	0.0	1.70	0.65	0.01	3.50	2.90	0.02	0.00	2.00	4.00	15.0	400

Source: wind-data.ch and Federal Office of Energy

Revenue and Policy Incentives

Since 2008, a feed-in tariff (FIT) system similar to that of Germany is in force. The FIT is designed to cover the estimated LCOE. Included in the FIT are the electricity market price and the value of the green electricity. For wind energy, the FIT in Switzerland is fixed between €110/MWh ($153/MWh) and €130/MWh ($181/MWh).

Typical Wind Energy Project in Switzerland

Onshore

Project Features

A wind farm in the Jura Mountains (1,000-1,200 meters above sea level), with 6 turbines of 2 MW, is used as the Swiss reference project for the cost calculations. Most of the wind projects in Switzerland are comprised of 2 MW turbines, with a typical rotor diameter of 82 m and a typical hub height of about 80 m. In some regions, the dimensions of the rotor and the tower height are limited by accessibility restrictions. In these regions, turbines with a rated power of 800-1000 kW and a typical hub height of 40-60 meters are used.

Investment Costs

Typical project specific investment costs in Switzerland amount to €1,790/kW ($2,488/kW). The percentage of investment cost for a turbine in Europe is, on average, around 76%. In Switzerland, however, this share ranges between 55 and 68%. This difference is attributed to the difficult accessibility of many wind sites and the high labor costs in Switzerland, which result in comparatively high balance of plant costs.

Operations and Maintenance Costs

Given that Switzerland has little experience with operational costs, we have compared the available local data with O&M costs published by EWEA. Based on these investigations, variable O&M costs in Switzerland are assumed at €31/MWh ($43/MWh).

Financing Costs

The following financing costs have been used for the cost calculations in Switzerland:

Table 7-3. Financing cost calculations

Market interest rate	5%
Required return on equity	7%
Equity share	30%
Economic life	20 yr
Depreciation period	20 yr
Inflation	0%
Loan duration	20 yr
Corporate tax rate (OECD)	21%

Revenue and Policy Incentives

There are two mutually exclusive revenue systems for producers of renewable electrical power in Switzerland.

The first revenue system is the FIT system, which is the base of the following cost calculations. This form of remuneration applies to the following technologies: hydropower (up to 10 megawatts), photovoltaics, wind energy, geothermal energy, biomass, and waste material from biomass. The tariffs on electricity from renewable energy sources (green power) are specified based on reference facilities for each technology and output category, and they are designed to cover the LCOE for each technology. Remuneration is applicable for a period of between 20 and 25 years, depending on the technology. A gradual downward curve is foreseen in these tariffs due to anticipated technological progress and the increased deployment of these technologies into the market. Tariff reductions will only apply to registered production facilities, which will receive remuneration through a constant tariff for the entire period of remuneration. Producers who decide in favor of the FIT system option cannot simultaneously sell their green power on the electricity market.

The second revenue system is the green electricity market. Producers outside the FIT system may sell their electricity on the market. Typically, their revenue will be the electricity market price plus a green power premium negotiated between the producer and the purchasing utility.

Source of Data

Wind energy capacity data: Swiss Wind Energy Association "Suisse Eole".

Investment and O&M Cost data: Survey of wind energy projects planned in 2008

Financing Costs: FIT calculations, Swiss Federal Office of Energy Model Input Assumptions

Tables 7-4 through 7-6 provide the modeling assumptions used in the LCOE estimation for onshore wind energy in Switzerland.

Table 7-4. Wind energy project features in Switzerland

		Onshore 2007	Onshore 2008	Offshore 2007	Offshore 2008
Unit size	MW	-	2	N/A	N/A
Number of turbines	N	-	6	N/A	N/A
Production	(full load hours)	-	1’750	N/A	N/A
Economic life	Years	-	20	N/A	N/A
Investment costs	€$_{2008}$/kW ($/kW)	-	1,790 (2,488)	N/A	N/A
O&M costs fixed	€/kW-year ($/kW-year)	-	-	N/A	N/A
O&M costs variable	€/MWh ($/MWh)	-	31 (43)	N/A	N/A
Decommission costs	€/kW ($/kW)	-	-	N/A	N/A

Table 7-5. Wind energy financing terms in Switzerland

		Onshore 2007	Onshore 2008	Offshore 2007	Offshore 2008
Return on equity	%	-	7	N/A	N/A
Return on debt	%	-	5	N/A	N/A
Equity share	%	-	30	N/A	N/A
Debt share	%	-	70	N/A	N/A
Loan duration	years	-	20	N/A	N/A
Corporate tax rate	%	-	21	N/A	N/A
FX rate	CHF/€	-	0.67	N/A	N/A
FX rate	$US/€	-	1.39	N/A	N/A

Table 7-6. Wind energy policy and revenue incentives in Switzerland

		Onshore 2007	Onshore 2008	Offshore 2007	Offshore 2008
Market price electricity	€/MWh ($/MWh)		-	N/A	N/A
FIT revenue	€/MWh ($/MWh)		125 (174)	N/A	N/A
FIT policy period	years		20	N/A	N/A
Upfront tax-based subsidy before tax	%		-	N/A	N/A
Production-based before tax credits	€/MWh($/MWh)		-	N/A	N/A
Production-based before tax credit policy period	years		-	N/A	N/A
Depreciation period	years		20	N/A	N/A
Reactive power bonus	€/MWh ($/MWh)		-	N/A	N/A
Low voltage ride through bonus	€/MWh ($/MWh)		-	N/A	N/A
Market Certificates	€/MWh ($/MWh)		Variable*	N/A	N/A
* negotiable between the producer and the purchaser					

Unique Aspects of Wind Projects in Switzerland

The production costs for wind energy in Switzerland are estimated at €120/MWh ($167/MWh), which is €58/MWh ($81/MWh) higher than in the Reference Case.

Cost Comparison

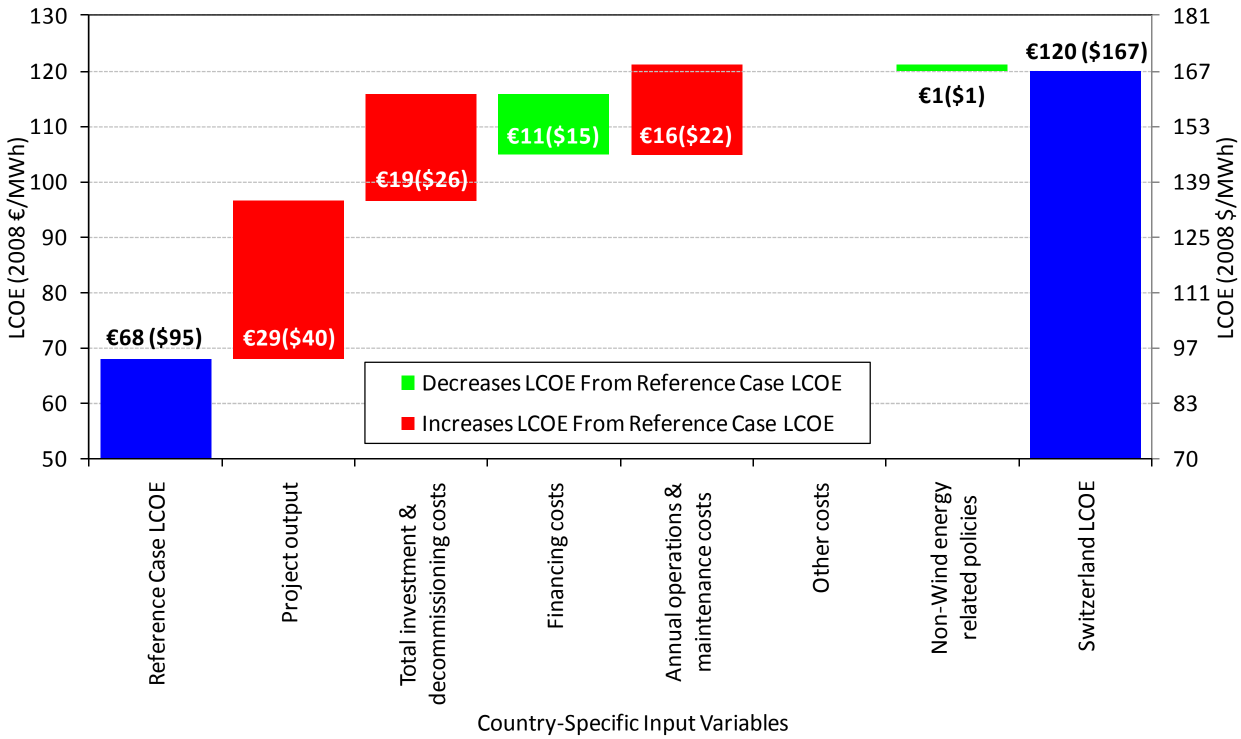


Figure 7-2. Wind energy costs in Switzerland compared to the Reference Case[37]

Project Output

The production of the Swiss project is considerably smaller than the production of the Reference Case. This is due to a moderate wind regime (1,750 full load hours).

Investment Costs

The total investment and decommissioning costs are higher in Switzerland than in the Reference Case. The difficult and complex accessibility of many sites and the high labor costs are the principal causes of high specific costs. The projects in Switzerland are small projects and, consequently, they receive lower discounts when purchasing wind turbines compared to larger projects.

Operations and Maintenance Costs

The operation and maintenance costs in Switzerland are higher than in the Reference Case. Icing and turbulence can cause problems to the plants and, consequently, more maintenance is required. There is little experience related to O&M costs in Switzerland.

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[37] Data labels are rounded to the nearest whole numbers. Therefore, the sum of input variables may differ slightly from the total Reference Case – Country LCOE differential (due to rounding).

Financing Costs
The finance costs in Switzerland are lower than in the Reference Case. The return on equity is set at 7%, though most projects are financed by utility companies that do not invest for financial reasons. Utility companies' main concern is the growing demand for green electricity.

Revenues and Support Mechanisms
FIT for wind energy in Switzerland ranges from €110-130/MWh ($153-181/MWh) with €125/MWh ($174/MWh) used in the modeling analysis. For a more detailed description of the revenues, see the "Revenue and Policy Incentives" paragraph. There are no other financial support mechanisms at the federal level.

There are support mechanisms for renewable electricity on the state level. In most states, they are focused on photovoltaic projects and they do not support wind energy.

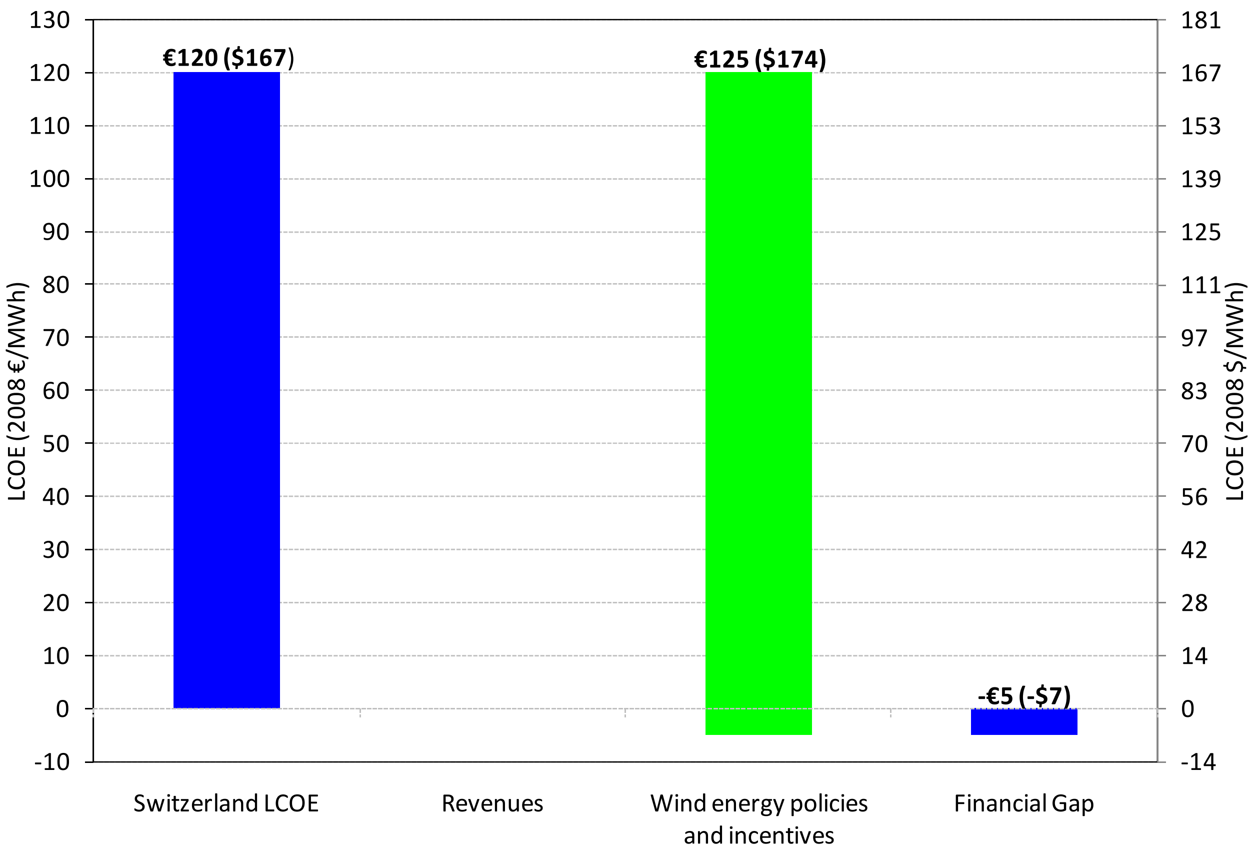

Figure 7-3. Wind energy revenue and policy incentives in Switzerland[38]

Financial Gap
Swiss policy incentives are designed to cover LCOE. Figure 7-3 shows that, for a typical wind energy project in Switzerland, the LCOE is covered by the FIT.

[38] Data labels are rounded to the nearest whole numbers. Therefore, the sum of the revenues, wind energy policies and incentives, and the financial gap may differ slightly from the country LCOE.

Summary

Table 7-7. Summary of wind projects for Switzerland[39]

		Onshore 2007	Onshore 2008	Offshore 2007	Offshore 2008
Levelized cost of energy	€/MWh ($/MWh)	-	120 (167)	N/A	N/A
Total revenue and wind energy policies and incentives	€/MWh ($/MWh)	-	125 (174)	N/A	N/A
Financial gap for developer	€/MWh ($/MWh)	-	-5 (-7)	N/A	N/A

[39] As previously mentioned, data labels are rounded to the nearest whole numbers. Therefore, the sum of the revenues, wind energy policies and incentives, and the financial gap may differ slightly from the country LCOE.

References

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Chapter 8: United States

Wind Energy in the United States

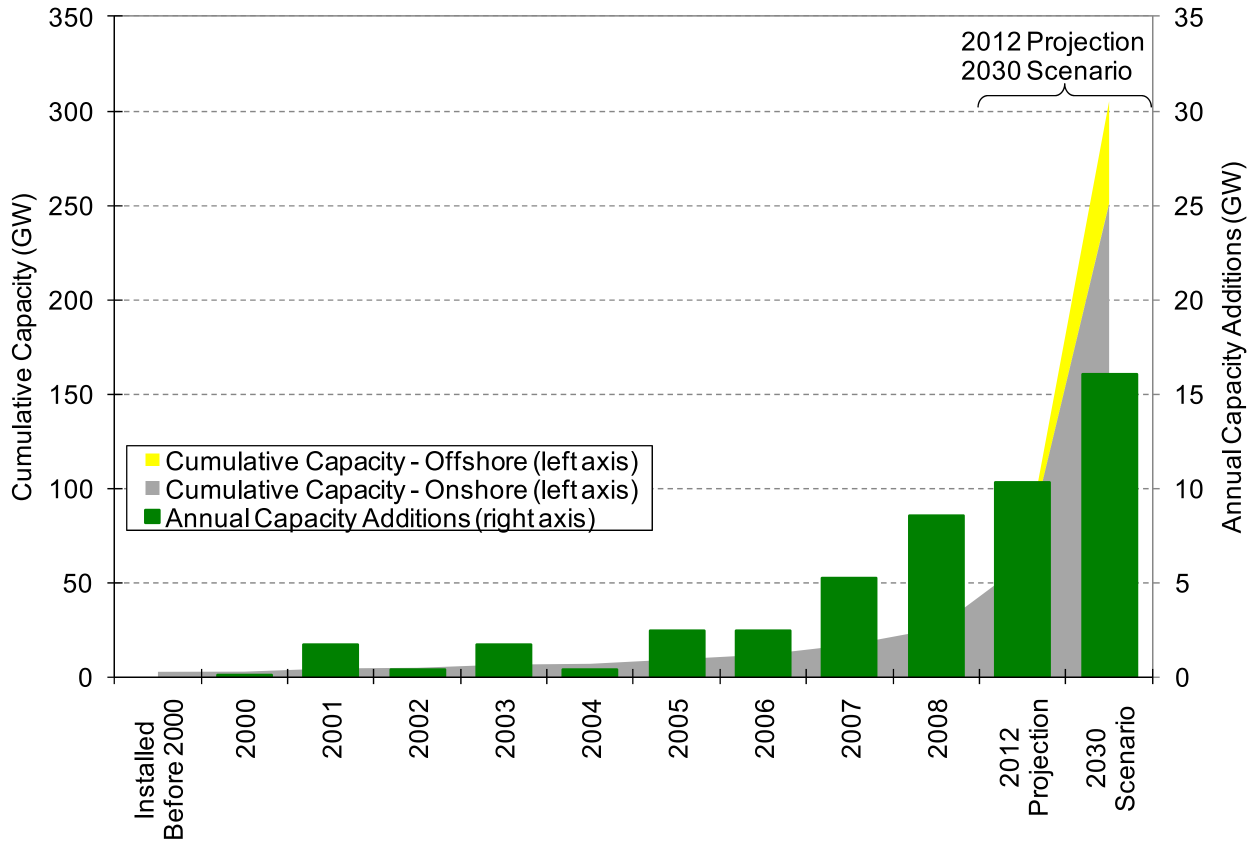
The following chapter describes onshore and offshore wind energy project and cost characteristics in the United States, specifically the assumptions used in modeling the levelized cost of energy (LCOE) for onshore wind technologies in 2008. Offshore wind energy is only briefly described due to the lack of historical development in the U.S. This chapter also presents the results of 2008 U.S. cost analysis in comparison to the Reference Case presented in Chapter 1.

Capacity, Energy Production, Near-Term Targets

Wind energy capacity in the United States expanded from approximately 2.5 gigawatts (GW) of cumulative installations in 2000 to over 25 GW by year-end 2008 (Figure 8-1). In each year since 2005, the wind industry recorded record U.S. annual installations with 8.5 GW of new capacity added in 2008.[40] Wind energy accounted for 42% of all new U.S. electrical generating capacity in 2008 and in an average year, the cumulative wind energy capacity could supply approximately 1.9% of total U.S. electricity consumption (Wiser and Bolinger 2009). As of 2008, all U.S. wind capacity was constructed onshore, however, several offshore wind projects were in the permitting and planning stages.

[40] In fact, this trend continued in the U.S in 2009 with just over 10 GW of wind capacity additions (AWEA 2010). For this report, wind energy capacity is generally discussed through 2008, the year used in the cross-country comparisons.

Figure 8-1 provides historical cumulative and annual U.S. wind energy installations, a 2012 wind energy projection, and a 2030 potential wind energy scenario.



Sources: AWEA 2009 (2000-2008), DOE 2008 (2030 scenario), EIA 2009 (2012 projection)

Figure 8-1. Cumulative and annual U.S. wind installations

The U.S. does not have explicit wind energy targets. Alternative data points to country wind energy targets are therefore shown in Figure 8-1. In the near-term, the Energy Information Administration (EIA) projects approximately 10 GW of U.S. wind capacity additions in 2012 – a modest increase over actual 2008 installations (EIA 2009).[41] Longer-term, a recent study analyzed a potential wind energy scenario where 20% of projected U.S. electricity demand would be met with wind energy by 2030 (DOE 2008). The study estimated that 305 GW of wind capacity would be required to meet the 20% milestone – the total comprised of both onshore and offshore wind energy technologies. In the study, total annual capacity additions ramp up to approximately 16 GW per year by 2018.

[41] As previously noted, just over 10 GW of wind energy installations were developed in 2009 (AWEA 2010).

Table 8-1 presents historical and projected *cumulative* wind energy installed in the U.S.

Table 8-1. U.S. cumulative wind energy installations (GW)

	Installed Before 2000	2000	2001	2002	2003	2004	2005	2006	2007	2008	2012 Projection	2030 Scenario
Onshore	2.5	2.6	4.3	4.7	6.4	6.8	9.2	11.7	16.9	25.5	59.5	251
Offshore	0	0	0	0	0	0	0	0	0	0	0	54

Sources: AWEA 2009, DOE 2008 (2030 scenario), EIA 2009 (2012 projection).

Table 8-2 shows historical and projected *annual* capacity additions.

Table 8-2. U.S. annual wind energy installations (GW)

<table>
<tr><th></th><th>Installed Before 2000</th><th>2000</th><th>2001</th><th>2002</th><th>2003</th><th>2004</th><th>2005</th><th>2006</th><th>2007</th><th>2008</th><th>2012 Projection</th><th>2030 Scenario</th></tr>
<tr><td>Onshore</td><td>N/A</td><td>0.1</td><td>1.7</td><td>0.4</td><td>1.7</td><td>0.4</td><td>2.4</td><td>2.5</td><td>5.2</td><td>8.6</td><td>10.3</td><td rowspan="2">16</td></tr>
<tr><td>Offshore</td><td>N/A</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td></tr>
</table>

Sources: AWEA 2009, DOE 2008 (2030 scenario), EIA 2009 (2012 projection).

Revenue and Policy Incentives

The primary sources of revenue for wind energy in the United States are sales of electricity and renewable energy market certificates (RECs). The economic value of the electricity and REC sales varies greatly from project to project based on regional, market, and other distinctions.

Wind energy in the United States is supported by the federal government principally through tax incentives. For wind energy technologies in 2008, these incentives include an inflation-adjusted production tax credit (PTC) and eligibility for accelerated depreciation of specific capital equipment (Schwabe et al. 2009).

Prior to 2004, the PTC expired on several occasions, though in each instance it was eventually renewed. This resulted in a boom and bust cycle of annual development from 2000-2004. Post 2004, however, the PTC has been in continuous force resulting in record U.S. annual installations each year from 2005 through 2009 (AWEA 2010).

The value of the federal tax incentives is a significant economic benefit for eligible renewable energy technologies. For wind projects on a present value basis, the combined benefit of the PTC and accelerated depreciation is estimated at 35% of a baseline project's installed costs (Bolinger 2010). On some occasions, the combined economic benefit of the PTC and accelerated depreciation can equal or exceed the system's revenues from the sale of electricity and RECs (Harper et al. 2007).[42]

Typical Wind Energy Project in the United States in 2008

The following section describes 2008 U.S. wind energy project characteristics. For comparison to other countries in this report, average or generally representative U.S. project characteristics

[42] This will be dependent on a number of location-specific factors that are constantly changing including the amount of wind generated, electric generation price, and local REC prices.

are presented below. However, precise wind energy project costs and attributes are location-specific and vary considerably for U.S. installations.

Onshore

Project Features

The average size of installed wind projects in the U.S. has ranged from approximately 35 MW in 1998-1999 to 120 MW in 2007, with an average installed project size of 83 MW observed in 2008 (Wiser and Bolinger 2009). Wind turbines installed in the United States over time have ranged in capacity from less than 0.5 MW to 3 MW, with an average turbine size of 1.67 MW for projects installed in 2008 (Wiser and Bolinger 2009). The most common turbine in the United States has a rated capacity of 1.5 MW, a rotor diameter of 77 m and a hub height of 80 m (GE 2010, Wiser and Bolinger 2009).

Project Performance

The quality of wind resource varies greatly from project to project, but overall the United States has an excellent wind regime. Full load hours for U.S. onshore wind projects range widely, approximately 1800-4400 hours, with a capacity-weighted average of 3,066 hours observed in 2008 (Wiser and Bolinger 2009).[43] It is important to note that the estimated full load hours are based on projects installed in 2007 that operated during 2008 – and not on total U.S. wind resource potential.

Investment Costs

Onshore wind project investment costs in the United States have been steadily increasing in recent years. For projects installed in 2008, investment costs ranged from roughly a minimum of €1,000/kW to more than €1,800/kW ($1,400/kW to $2,500/kW) with a capacity-weighted average of €1,378/kW ($1,915/kW) (Wiser and Bolinger 2009).[44] Wind turbine transaction prices also have been increasing in recent years; however, the decrease in demand from the 2008 financial crisis and accompanying economic slowdown reportedly has offered some turbine price and supply relief (Wiser and Bolinger 2009, Bolinger 2010).

Operations and Maintenance Costs

Operations and maintenance costs in the United States include both a fixed and a variable component and can be expressed in either manner. Capacity-based costs (€/kW) may include insurance, property taxes or various other facility costs; production-based costs (€/MWh), regular and unscheduled maintenance charges, equipment replacement or rebuilding, production-based land-lease payments, and other costs. In the United States, data for O&M costs are limited in availability and quality. As such, estimates of O&M costs are approximations only, and anecdotal evidence suggests that O&M costs, including premature component replacements, may be under-represented in the reported data. Furthermore, future O&M cost estimates may increase somewhat as turbines age or warranty periods expire.

For wind energy projects installed in the 2000s, Wiser and Bolinger estimate the 2000-2008 capacity-weighted average O&M cost of €5.8/MWh ($8.0/MWh) (Wiser and Bolinger 2009).

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[43] Based on a 35% capacity factor.
[44] All costs expressed in 2008 euros and dollars. Exchange rate of 1.39 $U.S/€ is used in dollar to euro conversions from December 31, 2008 (Federal Reserve 2010).

This O&M cost estimate, however, does not generally include property taxes. To include this expense, an additional €5.0/kW-year ($7.0/kW-year) estimated average property tax payment[45] is added to the Wiser and Bolinger O&M estimate. The total O&M cost estimate with property taxes is €7.4/MWh ($10.3/MWh) expressed in variable terms or €22.6/kW-year ($31.4/kW-year) in fixed terms.[46] For comparison, the 20% Wind Energy by 2030 study estimates slightly lower O&M costs by 2010 at approximately €6.9MWh ($9.6/MWh) (DOE 2008).[47]

Financing Costs

Wind project development in the United States in 2008 was often financed with high equity percentages and little to no project-based debt. The use of high equity percentages was due in part, to the historical intermittency of the production tax credit incentive. Debt financing could lengthen and complicate the financing stage of wind project development and risk missing economically valuable federal PTC deadlines (Harper et al. 2007).

The move away from debt financing also was due to the project development team's desire to maintain "upside potential" in the output of the system (including energy and sometimes environmental attributes); therefore, they did not lock in wind energy contract prices. Debt lenders in the United States typically require predetermined energy contract prices for the full output of the system (Cory and Schwabe 2009). Moreover, debt financing of wind projects in late 2008 was considerably more difficult to obtain than it was prior to the financial crisis because of reduced lending activities and risk aversion in the global credit markets (Schwabe et al. 2009).

For the modeling analysis, 100% equity investment is assumed, which was a recurring though not exclusive financing arrangement in the United States in 2008 (and less common internationally). In the modeling analysis, the required return on equity in 2008 is assumed at 7.5% (Chadbourne and Parke 2009). Note that rates of return on equity were impacted by the October 2008 financial crisis that widely increased the cost of equity financing, reportedly by 100-200 basis points (Chadbourne and Parke 2009, Wiser and Bolinger 2009).

Revenue and Policy Incentives:

The main revenue sources for U.S. onshore wind projects are 1) electricity and renewable energy certificate sales, through either long-term contracts or market-based prices, 2) the monetization of the federal production tax credit, and 3) the accelerated depreciation of certain capital equipment. In the United States, revenue from electricity and RECs varies greatly by region and market, (electricity: regulated vs. unregulated and RECs: voluntary vs. compliance towards renewable energy quota mandates). In the modeling analysis, an equally weighted-average wind energy price estimate is assumed between long term contract prices (inclusive of both electricity and RECs) and wholesale market prices (electricity only) *plus* RECs separately.[48] The 2008 average wind energy price is estimated at approximately €41.9/MWh ($58.2/MWh).[49]

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[45] Average property tax payment estimated from an internal NREL database.
[46] Based on 2008 U.S. project capacity and full load hours input assumptions.
[47] Estimate converted to 2008$ based on U.S. project capacity and full load hours input assumptions in 2008.
[48] Project owners of the 43% of wind power capacity added in 2008 included some merchant risk, while power marketers, who *may* also take merchant risk, purchased an additional 7% of new wind power capacity in 2008

The inflation-adjusted production tax credit was valued at approximately €15.1/MWh ($21.0/MWh) in 2008 (Wiser and Bolinger 2009). The accelerated depreciation of certain capital costs occurs over a schedule of six years, which is modeled at 20%, 32%, 19.2%, 11.5%, 11.5%, 5% in years 1-6 respectively.[50]

Sources

Data for the onshore modeling analysis was derived from a number of sources with preference given to publicly available resources whenever possible. A full listing of all data sources presented can be found in the reference section of this chapter. A more detailed description of the data for project features, project performance, investment costs, operations and maintenance costs, among other variables, can be found in the appendix of Wiser and Bolinger 2009.

Offshore

To date, no utility-scale offshore wind projects are operational or under construction in the United States. The 20% Wind Energy by 2030 report indicates that commercial offshore wind will be initially developed in the United States between 2012 and 2018 using shallow water technology, and primarily concentrated off the East Coast (DOE 2008). Estimates of anticipated offshore wind project features are included here for reference; however, due to the lack of operational offshore wind projects in the United States, these estimates are not included in the levelized cost of energy modeling analysis.

Project Features

U.S. offshore wind turbines are projected to be larger and operate in a better wind regime than onshore-based projects. For example, the Cape Wind offshore wind project that is under consideration in Massachusetts has announced planned turbine sizes of 3.6 MW (Capewind 2010). Full load hours are projected to range from 3,000 to approximately 4,800 hours (DOE 2008).

Investment Costs

Offshore wind investment cost estimates vary considerably and have been on an upward trajectory since the mid-2000s. Recent examination of investment costs for offshore wind projects proposed in the United States and Europe indicate an investment cost of approximately €3,100/kW ($4,300/kW). This represents projects planned for construction in the next few years.[51] The U.S. Offshore Wind Collaborative, meanwhile, anticipates offshore wind project costs to be as high as €3,300/kW ($4,600/kW) (USOWC 2009).

Operations and Maintenance Costs

As there are no operational offshore wind projects in the United States, there is a great deal of uncertainty in the projections of operations and maintenance costs. Although there is little

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(Wiser and Bolinger 2009). For this analysis, it is assumed that 50% of new wind energy in 2008 used market-based pricing (i.e., merchant), while the remaining 50% used long term contract prices.

[49] The following assumptions for 2008 prices were interpreted from Wiser and Bolinger 2009 and include:
(1) Long term wind energy contract prices (electricity + RECs) = $51.5/MWh,
(2) Wholesale spot market prices = $60/MWh, and
(3) Renewable energy certificates = $5/MWh.

[50] This depreciation schedule is based on the mid-year convention and ignores the 50% bonus depreciation that was available in 2008 and 2009.

[51] Estimate based on internal NREL analysis.

published data, recent estimates of operations and maintenance costs for offshore wind projects proposed in the United States and Europe indicate a total cost of approximately (€13.7/MWh) ($19/MWh).[52]

Financing Costs

Due to the perceived risks and lack of development or operational history of offshore wind energy in the United States, financing costs for the first few offshore projects are likely to be very high compared to onshore projects. Financing sources for offshore wind may include investors with higher risk tolerances (i.e., private equity funds) rather than traditional investors in onshore wind projects (i.e., insurance companies). For example, the required return for private equity fund investments may range from 25% to 35% for demonstrator technologies (Justice 2010). The U.S. federal government also offers federal loan guarantees that could help secure less expensive debt financing for commercial and innovative renewable energy technologies (offshore technologies might qualify for either). Under current law, however, the loan guarantee program is limited in funding availability and applicant eligibility (DOE 2010).

Federal and state level incentives available to onshore wind projects are assumed to be applicable to offshore as well. Federal incentives principally include the aforementioned PTC and accelerated depreciation of certain capital equipment. Individual states, primarily off the East Coast and Great Lakes region of the United States, have taken a variety of approaches and initiatives to facilitate offshore wind project development in their respective jurisdictions (USOWC 2009).

Sources

The primary sources of data for offshore wind characteristics include the "20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply" report (DOE 2008), "U.S. Offshore Wind Energy: A Path Forward" by the U.S Offshore Wind Collaborative, and various press releases regarding offshore wind development in the United States, though caution is exercised with the latter.

Model Input Assumptions

Tables 8-3 through 8-5 provide the modeling assumptions used in the levelized costs of energy analysis that follows. All cost assumptions are representative of wind projects in 2007 and 2008, and are expressed in 2008 euros and dollars. For a detailed description of the model and methodology, please see Chapter 1.

[52] Estimate based on internal NREL analysis.

Table 8-3. Wind energy project features in the U.S.

		Onshore 2007[53]	Onshore 2008	Offshore 2007[54]	Offshore 2008
Unit size	MW	1.65	1.67	-	-
Number of turbines	N	73	50	-	-
Production[55]	Full load hours	2,891	3,066	-	-
Economic life	Years	20	20	-	-
Investment costs	€/kW ($/kW)	1,241 (1,725)	1,378 (1,915)	-	-
O&M costs fixed[56]	€/kW ($/kW)	5.0 (7.0)	5.0 (7.0)	-	-
O&M costs variable[57]	€/MWh ($/MWh)	5.8 (8.0)	5.8 (8.0)	-	-
Decommissioning costs	€/kW ($/kW)	0	0	-	-
Other costs	€/MWh ($/MWh)	0	0	-	-

Sources: Wiser and Bolinger 2008, Wiser and Bolinger 2009.

Table 8-4. Wind energy financing terms in the U.S.

		Onshore 2007	Onshore 2008	Offshore 2007	Offshore 2008
Return on debt	%	N/A	N/A	-	-
Return on equity	%	6.5	7.5	-	-
Debt share	%	0	0	-	-
Equity share	%	100	100	-	-
WACC	%	6.5	7.5	-	-
Loan duration	Years	N/A	N/A	-	-
Corporate tax rate[58]	%	38.9	38.9	-	-
FX rate[59]	$US/€	1.39	1.39	-	-

Sources: Chadbourne and Parke 2009, Harper et al. 2007, Schwabe et al. 2009.

[53] As previously noted, all costs are expressed in 2008 euros and dollars.
[54] Although a range of projections for offshore wind project characteristics are provided in the previous section, offshore wind development is not included in the U.S. LCOE analysis.
[55] Assumptions are based on capacity factors of 33% in 2007 and 35% in 2008 (Wiser and Bolinger 2008, Wiser and Bolinger 2009).
[56] Due to limited annual data availability, capacity-based O&M costs are assumed to be equivalent in 2007 and 2008.
[57] Due to limited annual data availability, production-based O&M costs are assumed to be equivalent in 2007 and 2008.
[58] Note that the assumed federal and state income tax rates are 35% and 6% respectively (Harper et al. 2007). As state taxes are deductible from federal income, the combined effective tax rate is 38.9%.
[59] All costs are expressed in 2008 euros and dollars; therefore, the year-end 2008 $US/€ exchange rate is used for both 2007 and 2008 (Federal Reserve 2010).

Table 8-5. Wind energy revenue and policy incentives in the U.S.

		Onshore 2007	Onshore 2008	Offshore 2007	Offshore 2008
Market price electricity[60]	€/MWh ($/MWh)	38.2 (53.1)	41.9 (58.2)	-	-
Market price certificates[61]	€/MWh ($/MWh)	Included above	Included above	-	-
FIT revenue	€/MWh ($/MWh)	N/A	N/A	-	-
FIT policy period	Years	N/A	N/A	-	-
Upfront tax-based subsidy before tax	%	N/A	N/A	-	-
Production-based after tax credits[62]	€/MWh ($/MWh)	14.4 (20.0)	15.1 (21.0)	-	-
Production-based after tax credit policy period	Years	10	10	-	-
Depreciation period	Years	6	6	-	-
Reactive power bonus	€/MWh	N/A	N/A	-	-
Low voltage ride through bonus	€/MWh	N/A	N/A	-	-

Sources: Harper et al. 2007, Wiser and Bolinger 2009.

Cost of Wind Energy Generation

Cost Comparison

The U.S. wind energy input parameters were used to calculate the U.S. LCOE for 2007 and 2008. The 2008 U.S. LCOE (using all 2008 U.S. assumptions) was compared to the Reference Case (using all 2008 Reference Case assumptions), which is shown below.

The country-specific input variables were incrementally substituted from their Reference Case assumption to their U.S. assumption, one variable at a time. This enabled an estimation of each variable's impact on the Reference Case-U.S. LCOE differential. The U.S. LCOE is €3/MWh ($4/MWh) lower than the Reference Case LCOE, which is shown in Figure 8-2.

[60] The 2007 wind energy pricing assumptions were also interpreted from Wiser and Bolinger 2009.
[61] Estimates for the market price of renewable energy certificates are included in the market price of electricity calculation.
[62] PTC euro conversion is rounded to the nearest tenth.

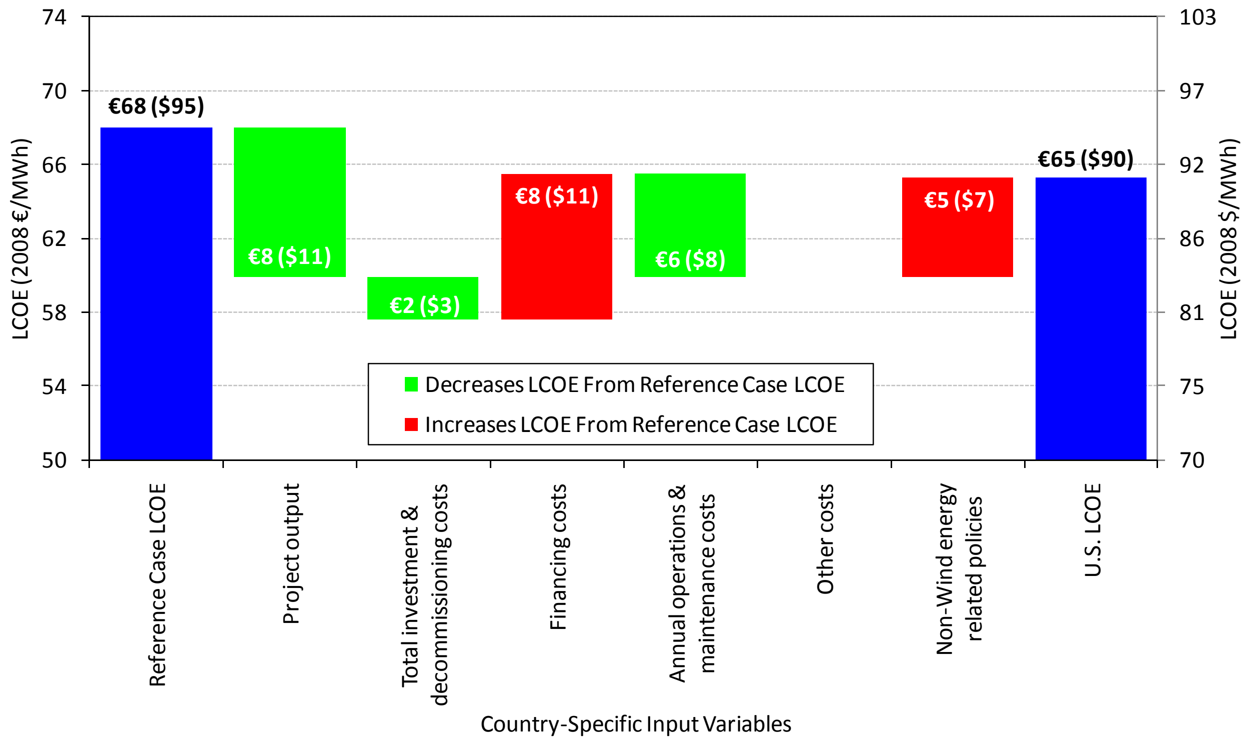

Figure 8-2. Wind energy costs in the U.S and the Reference Case in 2008[63]

Project Output:

A wind energy project in the United States benefits from a better wind regime on average than represented in the Reference Case. For U.S.-based onshore projects in 2008, an average of 3,066 full load hours is expected compared to 2,628 hours for the Reference Case. Greater project output in the U.S. *decreases* the U.S. LCOE relative to the Reference Case LCOE by approximately €8/MWh ($11/MWh).

Investment Costs

Total investment and decommissioning costs in the United States are approximately €72/kW ($100/kW) lower than the Reference Case. Average investment costs in the U.S. in 2008 were €1,378/kW ($1,915/kW) compared to €1,449/kW ($2,029/kW) for the Reference Case. Decommissioning costs, which include the dismantling of wind energy generation equipment and restoration of the project site, are assumed to be implicit in the all-in investment costs. Therefore, lower investment costs in the U.S. *decrease* the U.S. LCOE relative to the Reference Case LCOE by approximately €2/MWh ($3/MWh).

Financing Costs:

Financing costs in the U.S. in 2008 are higher than the Reference Case due to the high equity levels (100% in 2008), and because the Reference Case primarily uses debt financing. The rate

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[63] Data labels are rounded to the nearest whole numbers. Therefore, the sum of input variables may differ slightly from the total Reference Case – Country LCOE differential (due to rounding).

of return on equity for wind projects in the United States in 2008 (7.5%) is 200 basis points higher than the debt interest rate in the Reference Case (5.5%).

In the United States, rates of return on equity rose from 2007 to 2008 because of the loss of traditional tax equity investors from the financial crisis (Schwabe et al. 2009). This is also due, in part, to the nature of U.S. renewable energy tax incentive policies that offer similar benefits to other tax offsetting investments such as affordable housing, which offered returns in 2007 at approximately 6%, thereby setting a floor on equity investment returns (Chadbourne and Parke 2007). Greater financing costs in the U.S. *increase* the U.S. LCOE relative to the Reference Case LCOE by approximately €8/MWh ($11/MWh).

Operations and Maintenance Costs:

Total operations and maintenance costs in the United States are lower than the Reference Case. O&M costs can be represented as either a fixed or variable costs; therefore, comparisons to the Reference Case are made using a converted single charge estimate expressed in variable terms. Total O&M cost estimates in the United States fall well under the estimate of the Reference Case values, at €7/MWh ($10/MWh) vs. €13/MWh ($18/MWh) respectively. Estimates should be viewed with some caution however, as the U.S. wind industry has reportedly faced significant and ongoing challenges in projecting O&M cost estimates and reported data is often incomplete.

Some evidence suggests that O&M costs decrease with project size (Wiser and Bolinger 2009). This may contribute to the lower U.S O&M estimate compared to the Reference Case (as U.S. project sizes are larger than the Reference Case). O&M costs in the United States may also be mitigated due to warranty periods that may still be in effect for newer projects. Lower O&M costs in the United States *decrease* the U.S. LCOE relative to the Reference Case LCOE by approximately €6/MWh ($8/MWh).

Other Costs

Other costs are not modeled in the U.S. analysis separately as they are assumed to be implicit in the capital, financing, or the all-in O&M costs. Other costs could include low voltage ride through (LVRT) requirements by grid operators or reactive power costs. Fees for ancillary services are not typically charged directly to wind projects.

Non-Wind Energy Related Policy Impacts

Non-wind energy related policies increase the cost of wind energy in the United States compared to the Reference Case. Non-wind energy related policies include 1) the corporate tax rate and 2) the deduction of interest payments from corporate taxable income. The United States has a higher effective national corporate tax rate (38.9%) than the Reference Case (30%), which increases the U.S. LCOE. Additionally, because 100% equity financing is assumed, the U.S. LCOE is not reduced by the deduction of interest payments on taxable income. Non-wind energy related policies in the U.S. *increase* the U.S. LCOE relative to the Reference Case LCOE by approximately €5/MWh ($7/MWh).

Revenues and Wind Energy Policies and Incentives

The model's financial gap calculation is used to compare the value of the U.S. revenue variables (electricity and RECs) to the wind energy policies and incentives variables. The financial gap is first calculated without any revenue or wind energy policies and incentives variables. Then, the financial gap is recalculated with just the revenue variables included. Lastly, the financial gap is recalculated again with both the wind energy policies and incentives variables included. This incremental process identified the relative value of revenue variables to the wind energy policies and incentives variables.

Figure 8-3 compares the revenue variables to the wind energy policies and incentives variables, and together, how they constitute the U.S. LCOE. Of the €65/MWh ($91/MWh) U.S. LCOE in 2008, approximately €41/MWh ($57/MWh) is covered by revenue sources (electricity and REC sales) while €24/MWh ($33/MWh) is covered by specific wind energy policies and incentives (PTC and the *acceleration* of the depreciation schedule). In relative terms, around 2/3 of the U.S. LCOE is covered by the revenue components while the remaining 1/3 is covered by wind energy policies and incentives.

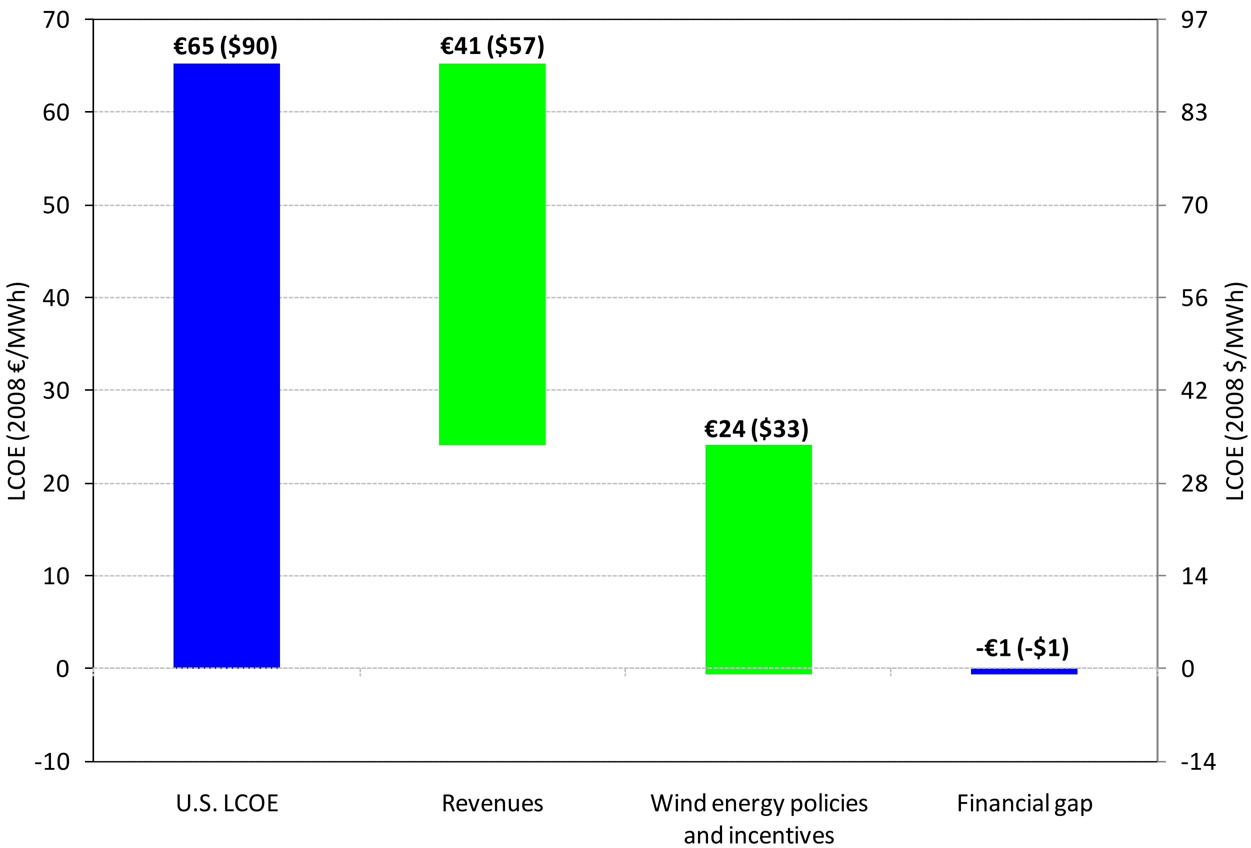

Figure 8-3. U.S. revenues and wind energy policies and incentives in 2008[64]

[64] Data labels are rounded to the nearest whole numbers. Therefore, the sum of the revenues, wind energy policies and incentives, and the financial gap may differ slightly from the country LCOE.

Financial Gap

The financial gap in the U.S. modeling analysis is approximated at -€1/MWh (-$1/MWh). This suggests that on average, a wind project developer in the United States receives sufficient cash flow from revenue and wind energy policies and incentives (if eligible) to meet the financial requirements to develop the project. This is also evident by the consecutive record of annual wind installations from 2005-2009 when the PTC was in continuous force. Conversely, annual installations dramatically declined when the PTC was not in effect (AWEA 2009).[65]

Summary of Wind Projects in the U.S.

In recent years, wind energy capacity in the United States has expanded rapidly. This was a result of an excellent wind regime, comparatively low costs, sufficient revenue sources, and favorable policy incentives, when available. While all wind energy developed to date in the United States has been onshore, the first offshore projects in the United States are progressing. The costs of wind energy in the United States are generally lower than the Reference Case primarily due to greater energy output, lower capital costs, and lower O&M expenditures. U.S. federal government policy incentives for wind energy, when authorized politically, have driven development in many, but not all, parts of the country. Taken together, the revenue and policy incentives result in a near zero financial gap for a wind energy project developer.

Table 8-6. Summary of results for the United States[66]

		Onshore 2007	Onshore 2008	Offshore 2007	Offshore 2008
Levelized cost of energy	**€/MWh ($/MWh)**	**58 (81)**	**65 (90)**	-	-
Total revenues and wind energy policies and incentives	€/MWh ($/MWh)	60 (83)	65 (90)	-	-
Financial gap for developer	€/MWh ($/MWh)	-2 (-3)	-1 (-1)	-	-

[65] See Figure 1.
[66] As previously noted, data labels are rounded to the nearest whole numbers. Therefore, the sum of the revenues, wind energy policies and incentives, and the financial gap may differ slightly from the country LCOE.

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Appendix A – Glossary of Variables

Year independent variables worksheet

Project Features		
Variable	**Definition**	**Specific components included**
Project title	The name of the project, for comparison purposes to other wind parks in other countries	For example, German on-shore reference wind park
Project Type	The type of wind park under investigation.	Onshore or offshore
Number of wind turbines	Total number of wind turbines that are represented in the wind park under investigation (likely a theoretical average wind park for the country).	Used to calculate the unit size and the full load hours
Rated power	The rated power per turbine	Used to calculate the unit size and the full load hours
Rotor Diameter	The diameter of the wind turbine rotor, in meters.	Informational; not used in any calculations.
Swept area	The total area swept by the rotors.	In square meters; informational – not used in any calculations.
Hub Height	The average height in meters where the hub is located, for the wind park under investigation.	Informational; not used in any calculations. While this may not be used in calculations, there should be a direct correlation between the average hub-height wind speed and the annual electricity production.
Long term average wind speed at hub height	The long-term average wind speed at the hub height.	Informational; not used in any calculations
Net electricity production	Average annual net electricity production of the wind park.	Used to calculate the full load hours.
Tax Capability	Limited or unlimited.	Option for the user – either the project must stand on its own (and absorb all tax benefits), or the project owner can have a parent company that can efficiently use all of the tax credits in that year. The tax credit applies to national/federal taxes only (and not state/municipal level).
Currency	The currency of all costs, revenues, incentives, etc.	Set to Euros, based on the representative dates for comparison: Calendar year 2007 (December 31st 2007) as well as Calendar year 2008 (December 31st 2008).
Fixed annual costs unit	Measurement unit used for fixed operations and maintenance costs	Set to €/kW
Variable annual costs unit	Measurement unit used for annual operations and maintenance costs	Set to €/kWh

Total investment cost		
Variable	**Definition**	**Specific components included**
Wind turbine	The upfront cost of the wind turbine and generation equipment.	Tower, rotor hub, rotor bearings, main shaft, main frame (supporting the drive train), gearbox, yaw system, pitch system, brake system, nacelle housing, generator, rotor blades, wind turbine transformer, and screws; but not including foundation or electrical interconnection (covered elsewhere).
Wind turbine transportation	The cost of transporting the wind turbine from the manufacturing factory, to the project development site, in preparation for erection.	Includes shipping, railroad costs, trucking costs and the cost of cranes used to complete delivery of the turbine to the project site.
Wind turbine installation	The cost of installing the wind turbine during project construction.	Includes the cost of the cranes during construction.
Sub-total: wind turbine cost	**The sum total of the above 3 wind turbine cost components**	**If no cost breakdown of the above components is available, the total value can be added here.**
Foundations	**The total cost of the foundation necessary for the wind park.**	**Includes the steel, concrete and other structural supports needed to support each wind turbine in the park.**
Internal grid	Electrical grid within the wind park itself, necessary to connect to the wind park's substation(s).	All wires within the wind park, including the wires up to and between the wind park's substation(s). If the substations connect to a final transformer before grid interconnection, it includes all the wires leading up to the final transformer. Includes cost of the primary controller (locally installed control equipment for a generation set to control the valves). Includes installation of supervisory control and data acquisition system (SCADA), or the wind farm monitoring system which allows the owner and the turbine manufacturer to be notified of faults or alarms, remotely start and stop turbines, and review operating statistics.
Grid connection, grid code compliance	Electrical grid required between the wind park's transformer and the existing electrical grid that are needed to electrically interconnect the wind park.	Wires from the wind park to the transmission system. This includes all additional equipment necessary for grid code compliance. If the wind park has many substations, including a final transformer, it just includes the wires between the final transformer and the grid.
Grid reinforcement	A weak grid can be reinforced by uprating its connection to the rest of the grid, in order to interconnect a wind park.	Equipment necessary to reinforce the existing transmission grid, including transmission upgrades, additional controls, and any incremental equipment.
Substations and transformer station	The cost of all of the wind park's substation(s) internal to the wind park's grid, leading up to and including the final transformer.	Before interconnection to the grid. Includes circuit breaker and switch. Transformer: a piece of electrical equipment used to step up or down the voltage of an electrical signal. Most turbines have a dedicated transformer to step up their voltage output to the grid voltage.
Sub-total electrical net / grid	**The sum total of the above 4 electrical grid components**	**If no cost breakdown of the above components is available, the total value can be added here.**

Certification	The cost of certifying the wind park, prior to interconnection to the grid.	Includes certified engineering drawings and comparing the actual construction of the wind park to those drawings.
Environmental surveys	The total cost of all environmental surveys required during the development phase of the wind park. These can be found in each country's specific requirement for an Environmental Impact Statement	Includes: • Pollutant potential (lubricants, etc.) • Sound level estimations • Visual impacts on landscape • Construction and operation impacts on wildlife and ecosystems • Specific bird and bat monitoring • Shadow flicker activity
Non-infrastructure development subtotal	Sum total of the above 2 non-infrastructure project development subcomponents.	If no cost breakdown of the above subcomponents is available, the total value can be added here.
O&M facilities	The cost of building any new roads and facilities necessary to carry out O&M work.	For wind turbine construction, regular O&M over the project's life, inspection of rotor blades and for change-out of big components.
Miscellaneous	Any other costs not included in the above project development costs.	Compensation to surrounding land owners.
Interest payment before operation	The total interest payment required before project operation.	Usually a result of construction-level debt as well as a loan to make a down payment on a wind turbine. This variable is financial within years -1 and -2, but is an upfront cost in the first year of operation, at which point this cash flow model starts.
Sub-total other project development costs	**Sum of above components**	**If no cost breakdown of the above sub-components is available, the subtotal value can be added here.**
Total Project Investment Costs	**Sum of above sub-totals for development components**	**If no cost breakdown of the above components is available, the total value can be added here.**

Total decommissioning costs		
Variable	**Definition**	**Specific components included**
Decommissioning, excl scrap value	The cost of decommissioning a wind park and removing it from the land (including foundations).	Cost of deconstructing the wind park and all related infrastructure, including cranes, dismantlement, shipping of materials and any necessary government certifications.
Returning the land to the natural state	The cost of returning the land to a predefined state.	Once the project is decommissioned.
Scrap value	The value of selling the scrap material at the time of decommissioning.	Materials in the wind park may be reused or sold for scrap value, including copper wire, steel, etc.
Net decommissioning costs	**Sum of above components**	**If no cost breakdown of the above components is available, the total value can be added here.**

Project Operation		
Variable	**Definition**	**Specific components included**
Operational time / full load hours, excluding derate	Full load hours are the wind park's average annual production divided by its rated power.	This is the total full load hours and includes any downtime for planned and unplanned maintenance. The higher the full load hours, the higher the wind park's production at the chosen site.
Derate of full load hours	Hours of non-operation of the wind park.	Included to capture loss of production due to icing conditions, etc.
Net operational time/full load hours	**The operational time/full load hours minus the derate.**	**Includes total net hours of operation (i.e. including the derate).**
Economic life	**The assumed economic life of the project, during which the total project costs must be recovered.**	**Does not include any residual life of the project, even if the project remains operational and in good working condition beyond the presumed economic life.**
Time horizon for cost calculations	**The period over which the levelized costs of electricity are calculated.**	**By default, is set to economic life, unless a value is entered by the user.**

Financial variables		
Variable	**Definition**	**Specific components included**
Loan duration	**The total number of years during which the loan must be repaid.**	**Includes both principal payments and interest payments.**
Loan - market interest rate	The amount charged by lenders for the use of the loan.	Cost in the form of a percentage of the amount borrowed.
Soft loan advantage	The soft loan advantage is the total incremental discount on the debt interest rate.	A soft loan provides a loan which is repaid at an interest rate that is lower than the going market rate. Values input elsewhere.
Return on debt	**The interest rate that the loan will earn annually during the loan period.**	**Percentage interest earned annually.**
Required return on equity, excl market volatility risk adder	The rate of return required by the equity investor in the wind park.	Percentage rate of return for equity.
Market volatility risk adder	Intended to capture the additional risk of participating in a competitive market, beyond the return on equity.	Percentage adder to account for the risk of unexpected volatility in the market.
Net required return on investment equity	**The percentage of return on equity to project investors (and not the developer) including the market volatility risk adder that is required by the equity investor.**	**Takes into account the percent of return on equity and market volatility.**
Local equity ownership	To capture any minimum local ownership requirements.	Applicable in Denmark (minimum of at least 20%). Values input elsewhere.
Equity share, excl local equity ownership	The percentage of equity contributed to cover the total investment cost and financing costs.	Total investment cost covers the turbine, the supporting equipment and infrastructure, as well as the cost of administration and financing.
Total equity share	**The sum of percentages of local equity share ownership and other equity share contributed to cover the total investment and financing costs.**	**Includes total equity provided from both local and non-local investors.**
Debt share	**The percentage of debt contributed to cover the total investment cost and financing costs.**	**A calculated value – based on the equity share entered (100% of the total project costs, minus the equity share).**

Corporate tax rate – national or federal	The total tax rate on the project from the federal/national government	As a percentage. Values input elsewhere.
Corporate tax rate-municipal or state	The total tax rate on the project from local governments.	As a percentage – includes local municipalities, provinces, states, etc. Values input elsewhere.
Net tax rate	**Sum of the federal and municipal/state corporate tax rates.**	**As a percentage – includes federal AND municipalities, provinces, states, etc.**
Depreciation period	**The total number of years over which project equipment is depreciated, for financing, accounting and tax purposes.**	**Value input elsewhere.**

Year dependent variables worksheet

Annual Costs **Variable**	**Definition**	**Specific components included**
Manufacturer-provided maintenance	Manufacturer-provided maintenance to the wind park for no additional cost the first one or more years of operation.	This cost is typically included in the installed cost of the wind park. Therefore, this zero cost in the early years should be noted.
Scheduled maintenance by internal staff	Regularly scheduled wind park maintenance that is provided by the project owner's staff.	Specific, expected costs for regular service of the wind park by company staff. Can be on a fixed basis (Euro/kW), or a variable basis (Euro/kWh)
External service contracts	Regularly scheduled wind park maintenance, provided by a third-party service contractor.	Specific, expected costs for regular service of the wind park by a service contractor. Can be on a fixed basis (Euro/kW), or a variable basis (Euro/kWh)
Operation costs	The annual cost required to operate the wind park.	This covers the technical operation of the wind park, including SCADA. Does not administration (covered elsewhere). Includes costs of numerical weather prediction.
Inspections	Hire a third-party contractor (not the company itself, nor the service contact company) to inspect the turbine.	This would include rotor blades reports (every 2-4 years), technical inspection of all components (every 2 years – 1 day per turbine). Timeframes of inspections can vary. Set on a Euro per kW basis.
Unscheduled repairs	Repairs and maintenance that was unanticipated.	Whether resulting from equipment failure, weather situations or other exogenous incidents.
O&M costs, fixed subtotal	**The sum total of the above 2 fixed O&M components.**	**If no cost breakdown of the above components is available, the total value can be added here.**
O&M costs, variable subtotal	**The sum total of the above 2 variable O&M components.**	**If no cost breakdown of the above components is available, the total value can be added here.**
Administration	**The cost of managing and overseeing the operation of the wind park.**	**Includes salaries, buildings, automobiles (and fuel), etc.**

Insurance	**The total annual cost of insurance that must be paid to protest against risks to and resulting from the wind park and its operation.**	**Includes property, liability, workers compensation, environmental, automobile and all other insurance types directly related to the wind park.**
Grid charges	Annual charges required to support interconnection with and operation of the system grid.	The user can input these as either capacity-based costs, or energy costs.
Grid costs, fixed	**Grid charges listed above**	
Grid costs, variable	**Balancing costs, listed above**	
Site lease	**The total cost paid to the landowner upon which the wind park is installed.**	**Whether this is paid on a per turbine basis or a total number of Euros, it is entered as a total Euro cost.**
Capacity-based taxes	**Total annual taxes that a project pays that are based on project capacity - annual Euros per kW**	**Note that percentage based taxes are entered as year independent variables in the previous worksheet. Values for capacity-based taxes are shown here, but are input elsewhere.**
Electricity consumption	Self-consumption of electricity.	For synchronization with the grid, unit start-up, etc. The user can input these as either capacity-based costs, or energy costs.
Environmental measurements, evaluations, etc.	Annual environmental measurements and evaluations required to maintain the wind park's permits and operation provisions.	The user can input these as either capacity-based costs, or energy costs.
Other annual costs, fixed subtotal	**Environmental measurement charges listed above**	
Other annual costs, variable subtotal	**Electricity consumption costs, listed above**	
Annual costs, fixed	Sum of above components	If no cost breakdown of the above components is available, the total value can be added here.
Annual costs, variable	Sum of above components	If no cost breakdown of the above components is available, the total value can be added here.

Other Revenues and Costs

Variable	Definition	Specific components included
Annual market participation fee	The annual charge for participating in the competitive electricity market.	Paid to the market agent/independent system operator.
Balancing costs	The total cost paid to incorporate the wind generation into the electric grid on an hour by hour basis. The incremental cost of the actual production in relation to the production forecasts.	In Euros per kWh. Cost may be paid through a formal balancing market, or informally through back-up power. Or, the cost may be included in the market price of electricity and difficult to separate out. The user can input these as either capacity-based costs, or energy costs.
Contract costs (transaction fees, etc)	The annual payment required to maintain contracts.	Transaction fees, etc. in terms of Euros per kWh.
Subtotal other costs	**Sum of market participation fee, balancing costs and contract costs**	
Reactive power	Premium to facilitate the voltage control of the grid.	Euros per kWh. Values input elsewhere.

Low voltage ride through	Premium to contribute to the grid stability.	Euros per kWh. Values input elsewhere.
Market price electricity	The average annual market price of electricity paid to a wind park.	Euros per kWh generated.
Market price certificates	The average annual market price of renewable attributes/certificates paid to a wind park.	Euros per kWh generated. May be set by a policy, or may be market based. Values input elsewhere.
Feed-in tariff revenue	The revenues from the feed-in tariff. Usually covers incremental payments required to cover the cost of the project, plus a reasonable return on equity. May also include the market price for electricity.	Can depend on the specific location, size of project, and year in which the wind park comes into commercial operation. May be added to the market price of electricity (premium) or a total fixed price (that includes the cost of electricity). Values input elsewhere.
Subtotal other revenues	**Sum of other revenues, listed above**	

Policies – both year independent and year dependent variables

Year independent variables		
Variable	**Definition**	**Specific components included**
Upfront tax-based investment subsidy – as a before-tax credit	An upfront subsidy that is based on tax credits, *before taxes are paid.* This is therefore applied to the project on a pre-tax basis.	The percentage of the upfront investment tax credit subsidy that is applied in the first year of operation, as a percentage of total project investment costs. The same percentage applies for either total project costs ($) or installed capacity costs ($/kW). This tax-based incentive is applied before the project pays taxes. As such, they have a greater value to the project, as they effectively also lower the taxes the project must pay in that first year. Option for the user – either the project must stand on its own (and absorb all tax benefits), or the project owner can have a parent company that can efficiently use all of the tax credits in that year. The tax credit applies to national/federal taxes only (and not state/municipal level).
Upfront tax-based investment subsidy – as an after-tax deduction (e.g. depreciation)	An upfront subsidy that is based on tax deductions, *after taxes are paid,* and is therefore applied to the project on an after-tax basis.	The percentage of the upfront investment tax deduction subsidy that is applied in the first year of operation, as a percentage of total project investment costs. The same percentage applies for either total project costs ($) or installed capacity costs ($/kW). This tax-based incentive is applied after the project pays taxes. Option for the user – either the project must stand on its own (and absorb all tax benefits), or the project owner can have a parent company that can efficiently use all of the tax credits in that year. The tax credit applies to national/federal taxes only (and not state/municipal level).
Upfront cash investment subsidy	The total value of the upfront investment subsidy, as a percentage of total project	The total value of the upfront investment subsidy, as a percentage of total project investment costs.

	investment costs.	
Soft loan advantage	The soft loan advantage is the total incremental discount on the debt interest rate.	A soft loan provides a loan which is repaid at an interest rate that is lower than the going market rate.
Local equity ownership	To capture any minimum local ownership requirements.	Applicable in Denmark (minimum of at least 20%).
Depreciation period	The total number of years over which project equipment is depreciated, for financing, accounting and tax purposes.	
Corporate tax rate – national or federal	The total tax rate on the project from the federal/national government	As a percentage.
Corporate tax rate-municipal or state	The total tax rate on the project from local governments.	As a percentage – includes local municipalities, provinces, states, etc.

Year dependent variables

Variable	Definition	Specific components included
Capacity-based taxes	Annual Euro per kW taxes	Capacity-based taxes that require annual payment and that change depending on the year.
Feed-in tariff revenue (e.g. production based incentives)	The revenues from the feed-in tariff or production based incentive. Usually covers incremental payments required to cover the cost of the project, plus a reasonable return on equity. *May also include the market price for electricity.*	Can depend on the specific location, size of project, and year in which the wind park comes into commercial operation. May be added to the market price of electricity (premium) or a total fixed price (that includes the cost of electricity). Countries with time dependent tariff (e.g. Germany) should enter yearly values – even if they are at the same level for most of the years.
Feed-in tariff policy period	The total time period during which feed-in tariff or production subsidies are paid.	The policy period cannot be longer than the assumed economic life of the project. For a single country, there may be different FIT payment levels, over different periods of time. The total FIT policy period should be entered here.
Production-based before-tax credits	Production-based (i.e. per kWh) tax credits intended to subsidize wind generation, applied *before taxes.* This is therefore applied to the project on a pre-tax basis.	These production-based tax credits (Euros per kWh) are applied *before* the project pays taxes (on a pre-tax basis). As such, they have a greater value to the project, as they effectively also lower the taxes the project must pay. Option for the user – either the project must stand on its own (and absorb all tax benefits), or the project owner can have a parent company that can efficiently use all of the tax credits in that year. The tax credit applies to national/federal taxes only (and not state/municipal level).
Production-based before-tax credit: policy period	The total time period during which annual before-tax credits are paid.	The policy period cannot be longer than the assumed economic life of the project.
Production-based after-tax deductions	Production-based (i.e. per kWh) tax deductions intended to subsidize wind generation, applied *after taxes.* This is therefore applied to the project on an after-tax basis.	These production-based tax deductions (Euros per kWh) are applied *after* the project pays taxes (on a pre-tax basis). Option for the user – either the project must stand on its own (and absorb all tax benefits), or the project owner can have a parent company that can efficiently use all of the tax credits in that year. The tax credit applies to

		national/federal taxes only (and not state/municipal level).
Production-based after-tax deductions: policy period	The total time period during which annual before-tax credits are paid.	The policy period cannot be longer than the assumed economic life of the project.
Reactive power bonus	Premium to facilitate the voltage control of the grid.	Euros per kWh
Low voltage ride through	Premium to contribute to the grid stability.	Euros per kWh
Market price certificates	The average annual market price of renewable attributes/ certificates for the wind park, whether set by a market or set by a government policy.	Euros per kWh generated. The user should enter the blended weighted average market price for all certificates sold into different markets (i.e. at different market prices).
Accelerated Depreciation	The schedule of depreciating the value of the equipment, for financing, accounting and tax purposes.	The amount of depreciation taken each year is slightly higher than the earlier years of an asset's life. Set as % of total initial investment, on an annual basis. Does not have to be linear.
Depreciation period	The total number of years over which project equipment is depreciated, for financing, accounting and tax purposes.	The model expects the user to define the years and rate at which a project's value is depreciated. If a country uses a methodology where the remaining value is depreciated in each subsequent year, the user will have to approximate the depreciation schedule and values through a proxy.

Output variables

Variable	Definition	Specific components included
Financial gap	The financial gap that is required to finance a project	The total cost (including financing costs), minus revenues and incentives needed to meet the required return on equity investment. Euros per MWh generated.
Levelized electricity generation cost	The present day average cost per kWh produced by the wind park over the economic life of the wind park.	Includes all costs (investments, reinvestments, operation and maintenance), revenues, incentives and financing costs. Levelized costs are calculated using the discount rate and the turbine lifetime.

REPORT DOCUMENTATION PAGE

Form Approved
OMB No. 0704-0188

1. REPORT DATE *(DD-MM-YYYY)*	2. REPORT TYPE	3. DATES COVERED *(From - To)*
March 2011	Technical Report	

4. TITLE AND SUBTITLE
IEA Wind Task 26 - Multi-national Case Study of the Financial Cost of Wind Energy Work Package 1 Final Report

5a. CONTRACT NUMBER
DE-AC36-08GO28308

5b. GRANT NUMBER

5c. PROGRAM ELEMENT NUMBER

6. AUTHOR(S)
P. Schwabe, M. Hand, and S. Lensink

5d. PROJECT NUMBER
NREL/TP-6A42-48155

5e. TASK NUMBER
WW3D1000

5f. WORK UNIT NUMBER

7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES)
National Renewable Energy Laboratory
1617 Cole Blvd.
Golden, CO 80401-3393

8. PERFORMING ORGANIZATION REPORT NUMBER
NREL/TP-6A42-48155

9. SPONSORING/MONITORING AGENCY NAME(S) AND ADDRESS(ES)

10. SPONSOR/MONITOR'S ACRONYM(S)
NREL

11. SPONSORING/MONITORING AGENCY REPORT NUMBER

12. DISTRIBUTION AVAILABILITY STATEMENT
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161

13. SUPPLEMENTARY NOTES

14. ABSTRACT *(Maximum 200 Words)*
The lifetime cost of wind energy is comprised of a number of components including the investment cost, operation and maintenance costs, financing costs, and annual energy production. Accurate representation of these cost streams is critical in estimating a wind plant's cost of energy. Some of these cost streams will vary over the life of a given project. From the outset of project development, investors in wind energy have relatively certain knowledge of the plant's lifetime cost of wind energy. This is because a wind energy project's installed costs and mean wind speed are known early on, and wind generation generally has low variable operation and maintenance costs, zero fuel cost, and no carbon emissions cost. Despite these inherent characteristics, there are wide variations in the cost of wind energy internationally, which is the focus of this report. Using a multinational case-study approach, this work seeks to understand the sources of wind energy cost differences among seven countries under International Energy Agency (IEA) Wind Task 26 – Cost of Wind Energy. The participating countries in this study include Denmark, Germany, the Netherlands, Spain, Sweden, Switzerland, and the United States. Due to data availability, onshore wind energy is the primary focus of this study, though a small sample of reported offshore cost data is also included.

15. SUBJECT TERMS
wind energy; cost of wind energy; multi-national cost of wind energy; financial cost of wind energy

16. SECURITY CLASSIFICATION OF: a. REPORT	b. ABSTRACT	c. THIS PAGE	17. LIMITATION OF ABSTRACT	18. NUMBER OF PAGES	19a. NAME OF RESPONSIBLE PERSON
Unclassified	Unclassified	Unclassified	UL		
					19b. TELEPHONE NUMBER *(Include area code)*

Standard Form 298 (Rev. 8/98)
Prescribed by ANSI Std. Z39.18

F1147-E(10/2008)