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Wind Turbine Design Cost and Scaling Model

L. Fingersh, M. Hand, and A. Laxson

Technical Report
NREL/TP-500-40566
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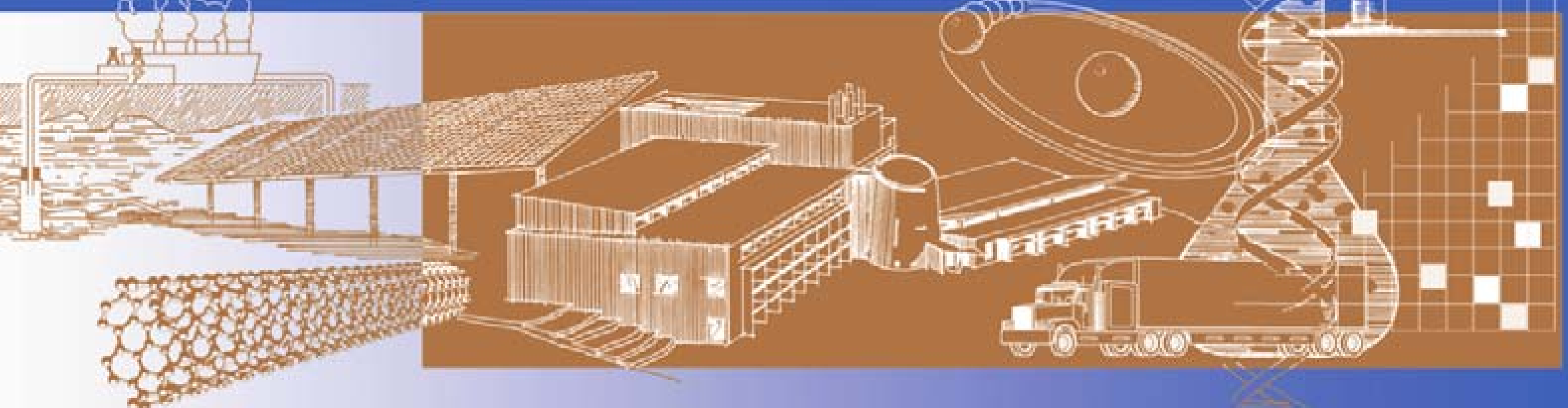

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National Renewable Energy Laboratory
1617 Cole Boulevard, Golden, Colorado 80401-3393
303-275-3000 • www.nrel.gov

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Executive Summary

The National Renewable Energy Laboratory's (NREL) National Wind Technology Center has been working to develop a reliable tool for estimating the cost of wind-generated electricity, from both land-based and offshore wind turbines. This model is also intended to provide projections of the impact on cost from changes in economic indicators such as the Gross Domestic Product (GDP) and Producer Price Index (PPI). The model described has been built from work originally done by University of Sutherland under a United Kingdom Department of Trade and Industry Study and work performed for the U.S. Department of Energy (DOE) under its Wind Partnerships for Advanced Component Technology (WindPACT) projects. These models are intended to provide reliable cost projections for wind-generated electricity based on different scales (sizes) of turbines. They are not intended to predict turbine "pricing," which is a function of volatile market factors beyond the scope of this work. The models in this study allow projections of both land-based and offshore technologies, though offshore technologies are still in their infancy and forecasts are extremely rough. These models also allow modeling of the cost impacts of certain advanced technologies that were studied under the WindPACT and Low Wind Speed Technology (LWST) projects. Cost estimates are projected based on turbine rating, rotor diameter, hub height, and other key turbine descriptors. Cost scaling functions have been developed for major components and subsystems. Wherever current industry information is available, the models have been cross checked or improved based on this industry information. Annual energy production has been estimated based on the Weibull probability distributions of wind, a standardized power curve, physical description of the turbine and physical constants and estimates from aerodynamic and engineering principles associated with aero and machine performance (efficiencies). The product of this work is a set of scaling functions and a tool that is capable of constant update and improvement as additional data are made available. As additional data become available and this model is updated it is expected that new versions of this description will be issued.

1.0 Purpose of Model

When evaluating any change to the design of a wind turbine, it is critical that the designer evaluate the impact of the design change on the system cost and performance. The designer must consider several elements of this process: initial capital cost (ICC), balance of station (BOS), operations and maintenance (O&M), levelized replacement cost (LRC), and annual energy production (AEP). As wind turbines grow more sophisticated and increase in size, the impact of design on these elements is not always clear. For example, increasing AEP may increase ICC. If one step does not balance out the other, proposed improvements may actually have a negative overall impact.

The levelized COE has been used by DOE for some years to attempt to evaluate the total system impact of any change in design. This levelized COE is calculated using a simplified formula that attempts to limit the impact of financial factors, such as cost of money in wind farm development, so that the true impact of technical changes can be assessed.

The constant pressure to grow wind turbines has also been a challenge for designers. It is often difficult to determine what the total impact of increasing the rating or rotor diameter of a turbine will be. Models that predict component cost and performance at a range of sizes or configurations have been a goal of the Federal Wind Energy Program for some years. Such models are invaluable to modelers and forecasters when attempting to project technology pathways.

The work described in this document is an attempt to develop such a model, in a spreadsheet format, that can be used by designers to look at the impact of scaling and configuration on overall COE.

A note of caution to the reader. Much of the data used to develop scaling functions for machines of greater than 1 to 2 MWs is based on conceptual designs. Many components are scaled using functions that are close to a cubic relationship. This is what would normally be expected for technologies that did not undergo design innovations as they grew in size. The WindPACT studies were not designed as optimization studies, but were structured to identify barriers to size increase. Once such barriers are clearly identified and evaluated, it is expected that designers will find innovative ways to get around them. This model should be viewed as a tool to help identify such barriers and quantify the cost and mass impact of design changes on components without such innovation. With expansion it can then be used to help designers to quantify the net value of an improvement of any component. The importance of this should not be lost on those that use these models. It would be difficult for a user to exercise these models in an optimization mode without taking into account the innovation that could be applied to the design of many of the major components to reduce the size, mass and cost as they increase in rating.

2.0 History

There have been several attempts to develop modern scaling models. But because wind turbines have changed in size and configuration so rapidly, many models are out of date before they can be used effectively by designers. In the mid to late 1990s, the configuration for utility-scale turbines began to stabilize around the three-bladed, upwind design. During this same period, an effort at the University of Sunderland resulted in a set of scaling tools for the machines of the period [1]. This report contained valuable models to predict the impact of machine size on turbine components. But within a few years of the publication, machine size had increased by a factor of 2 to 4 in some cases, and several new technology approaches began to be incorporated.

Beginning in 1999, DOE began its WindPACT projects. These projects were focused on determining the potential technology pathways that would lead to more cost-effective wind turbine design. One of the elements and goals of this work was to determine the impact of increased machine size and machine configuration on total COE. This was done by completing several major studies. In each study, the team completed conceptual designs of turbines and wind systems at a range of sizes, from 750 kW to 5 MW. Wherever possible, these studies developed scaling relationships for subsystems, components, or cost elements across the range of sizes. This work culminated in seven principal studies:

- *Composite Blades for 80- to 120-m Rotors* [2]
- *Turbine, Rotor and Blade Logistics* [3]

- *Self Erecting Tower and Nacelle Feasibility* [4]
- *Balance of Station Cost* [5]
- *Turbine Rotor Design Study* [6]
- *Drive Train Alternative Design Studies* [7] [8]

The scaling relationships developed during these studies also evaluated the relationships developed in the earlier Sunderland model for use or guidance. Where superior information was developed during the study efforts, the Sunderland model was abandoned and new relationships were defined.

In addition to looking at scaling issues, the turbine rotor design study [6] developed structural models for more than 20 different turbine rotor and tower configurations and determined the structural and cost impact of these different design configurations. This rotor design study summarizes the scaling results up to the time of its completion in June 2002. The two alternative drivetrain design studies extended this work for drivetrains by each exploring a number of alternative drivetrain (gear box, generator, power converter) configurations at different machine sizes, and the total impact of these configurations on total COE.

In 2002, the DOE Wind Energy Program began supporting LWST projects. These industry partnerships extended the work of WindPACT by beginning the development of actual turbine components and prototypes that would be expected to lower the COE for utility-scale wind turbines. Several of these projects have been completed, and a number of them are still under way and provide greater insight into the actual cost of systems and components in the large machines. Though much of the data from these studies are confidential, the aggregate results can be used to provide valuable additional data points and cross checks for scaling relationships.

The baseline turbines in all of these studies was a three bladed upwind turbine modeled after the Zond/Enron/GE machines that evolved into the GE 1.5 MW machine. They are assumed to be grid-connected, full span pitch controlled, variable speed turbines with active yaw and steel tubular towers. However, the data for cost and mass of components in each of these studies were derived independently of any Zond/Enron/GE data. Costs were based on a 50 MW wind farm composed of machines of mature production installed in the upper Midwest. All cost calculations were based on a low wind speed site with an annual average wind velocity of 5.8 meters per second with a wind shear of 1/7. A more detailed description of turbines in each study can be found in the beginning of the study reports identified in the Appendix.

Beginning in late 2005, researchers at NREL's National Wind Technology Center began developing a spreadsheet model of these scaling relationships to assist in projecting future wind turbine costs. The purpose of this work was two-fold. First, it was to provide a traceable process for projecting turbine cost and size impacts for the Government Performance and Results Act (GPRA). This was to be accomplished by providing detailed reproducible cost models for use in the National Energy Modeling System (NEMS) runs. The second purpose of this work was to provide a baseline tool for evaluating the impact of machine design and growth on cost for proposed offshore wind turbine systems.

To prepare this spreadsheet model, the WindPACT rotor study was used as a primary scaling formula source. In the process of computerizing these formulas and comparing them to current technology, a number of deviations were noted between this 2002 model and current trends. Data for these comparisons came from several sources and will be discussed in more detail later in this report. The result was a set of models that could be used to project the total COE for a wind turbine over a range of sizes and configurations. This model is not intended as an end result in itself, but as a starting point for a continually growing and improving tool that constantly incorporates new data as the technology grows and improves.

3.0 Model Description

3.1 Overview

The DOE/NREL scaling model is a spreadsheet-based tool that uses simple scaling relationships to project the cost of wind turbine components and subsystems for different sizes and configurations of components. The model does not handle all potential wind turbine configurations, but rather focuses on those configurations that are most common in the commercial industry at the time of writing. This configuration focuses on the three-bladed, upwind, pitch-controlled, variable-speed wind turbine and its variants. It is believed that this configuration will dominate wind energy for some extended period, and the model can best be maintained using data for these designs as they become available. The model is not intended to be a stagnant, final product, but rather a constantly evolving tool that can be refined as new data become available.

Formulas in the model, in its early versions, are quite simple. In most cases, cost and mass models are a direct function of rotor diameter, machine rating, tower height, or some combination of these factors. In cases where better definition is available, more sophisticated approaches are used or are under development. These will be discussed in each component section below. The results of each model are assumed to be in 2002 dollars. This has been done for purposes of consistency. Where cost data was available from different years, it was converted to 2002 dollars before the cost and scaling factors were developed. Cost data is based on a mature design and a 50 MW wind farm installation, with mature component production.

3.2 COE

Though the model produces component cost and mass figures where they can be supported, its primary output is levelized COE.

3.2.1 Cost of Energy

COE is calculated using the following equation:

$$\text{COE} = \frac{(\text{FCR} \times \text{ICC}) + \text{AOE}}{\text{AEP}_{net}}$$

where COE $\equiv$ levelized cost of energy ($/kWh) (constant $)
FCR $\equiv$ fixed charge rate (constant $) (1/yr)
ICC $\equiv$ initial capital cost ($)
AEP_{net} $\equiv$ net annual energy production (kWh/yr)
AOE $\equiv$ annual operating expenses
$\equiv$ $LLC + \dfrac{(O\&M + LRC)}{AEP_{net}}$
LLC $\equiv$ land lease cost
O&M $\equiv$ levelized O&M cost
LRC $\equiv$ levelized replacement/overhaul cost

3.2.2 Fixed Charge Rate

The fixed charge rate (FCR) is the annual amount per dollar of initial capital cost needed to cover the capital cost, a return on debt and equity, and various other fixed charges. This rate is imputed from a hypothetical project, modeled using a pro forma cash flow spreadsheet model. For the current base model, FCR includes construction financing, financing fees, return on debt and equity, depreciation, income tax, and property tax and insurance, and is set to 0.1158 per year. In future improvements to the model, alternative financial options will be provided. The 10-year Section 45 Renewable Energy Production Tax Credit is not included in the FCR, nor is it considered in any of the models.

3.2.3 Initial Capital Cost

The initial capital cost is the sum of the turbine system cost and the balance of station cost. Neither cost includes construction financing or financing fees, because these are calculated and added separately through the fixed charge rate. The costs also do not include a debt service reserve fund, which is assumed to be zero for balance sheet financing.

Primary cost elements tracked in the model include the following:

- Rotor
    - Blades
    - Hub
    - Pitch mechanisms and bearings
    - Spinner, nose cone
- Drive train, nacelle
    - Low-speed shaft
    - Bearings
    - Gearbox
    - Mechanical brake, high-speed coupling, and associated components
    - Generator
    - Variable-speed electronics
    - Yaw drive and bearing
    - Main frame

    - Electrical connections
    - Hydraulic and cooling systems
    - Nacelle cover
- Control, safety system, and condition monitoring
- Tower
- Balance of station
    - Foundation/support structure
    - Transportation
    - Roads, civil work
    - Assembly and installation
    - Electrical interface/connections
    - Engineering permits

When evaluating offshore turbines, the following additional components or elements are considered:

- Marinization (added cost to handle marine environments)
- Port and staging equipment
- Personal access equipment
- Scour protection
- Surety bond (to cover decommissioning)
- Offshore warranty premium

3.2.4 Annual Operating Expenses

Land Lease Cost/Bottom Lease Cost

Annual operating expenses (AOE) include land or ocean bottom lease cost, levelized O&M cost, and levelized replacement/overhaul cost (LRC). Land lease costs (LLC) are the rental or lease fees charged for the turbine installation. LLC is expressed in units of $/kWh.

Levelized O&M Cost

A component of AOE that is larger than the LLC is O&M cost. O&M is expressed in units of $/kWh. The O&M cost normally includes

- labor, parts, and supplies for scheduled turbine maintenance
- labor, parts, and supplies for unscheduled turbine maintenance
- parts and supplies for equipment and facilities maintenance
- labor for administration and support.

Levelized Replacement/Overhaul Cost

LRC distributes the cost of major replacements and overhauls over the life of the wind turbine and is expressed in $/kW machine rating.

3.2.5 Net Annual Energy Production

The net AEP is a calculation of the projected energy output of the turbine based on a given annual average wind speed. The gross AEP is adjusted for factors such as rotor coefficient of power, mechanical and electrical conversion losses, blade soiling losses, array losses, and machine availability. The model used for calculating AEP is described in greater detail in section 3.5.

3.3 Cost Summary

Costs used to develop scaling curves in these models are based on 2002 dollars. Where data from other periods have been incorporated into the data for evaluating the scaling curves, they have been deescalated using the Producer Price Indexes (PPIs) described below.

In 2004 and 2005, rapid changes in the cost of such key materials as structural steel and copper highlighted the impact that individual material costs have on major wind turbine components. To compensate for such fluctuations and to accurately project the cost of components into out years, a component cost escalation model was developed based on the PPI. The PPI maintained by the U.S. Department of Labor, Bureau of Labor Statistics, tracks costs of products and materials over a broad range of industries. They are sorted by North American Industry Classification System (NAICS) codes that provide a rational grouping of U.S. industries and products. The PPI was scoured for categories comparable to wind turbine components. In some instances, a wind turbine component is represented by a composite of several PPI categories. Labor-intensive components such as rotor blades and electrical interface components include a labor cost escalator, which was specified as the general inflation index, based on the Gross Domestic Product (GDP). Other components, such as the hub, are delivered in an essentially finished state so it was assumed that labor costs were included in the appropriate PPI category. While this approach allows the escalation of costs from the 2002 baseline date to the present, it does not allow for projections into the future.

Table 1 provides an example of the differences that would be seen in using PPIs for selected categories versus using the GDP for all categories. The TC Baseline is the wind energy technical characterization work being completed by NREL for DOE.

Table 1. GDP Escalation for All Categories Versus PPI for Selected Categories.

	2002 baseline costs	2005 – PPI component escalation	2005 – GDP general inflation escalation
LWST, $/kW installed	981	1135	**1079**
LWST, $/kWh at 5.8 m/s	0.0480	0.0551	**0.0528**
TC Baseline, $/kW installed	1049	1225	**1153**
TC Baseline, $/kWh at 5.8 m/s	**0.0433**	**0.0501**	**0.0476**

The PPI categories and the associated NAICS codes are detailed below for each wind turbine component listed in the baseline cost estimate. These are provided to indicate to the reader which PPI categories are used in this model to develop commodity inflation factors. The percentages expressed here are the percentages of each commodity assumed to make up the final product, not percentage increase in cost.

- Baseline blade material cost
    - Fiberglass fabric (NAICS Code 3272123) = 60%
    - Vinyl type adhesives (NAICS Code 32552044) = 23%
    - Other externally threaded metal fasteners, including studs (NAICS Code 332722489) = 8%
    - Urethane and other foam products (NAICS Code 326150P) = 9%
- Advanced blade material
    - Fiberglass fabric (NAICS Code 3272123) = 61%
    - Vinyl type adhesives (NAICS Code 32552044) = 27%
    - Other externally threaded metal fasteners, including studs (NAICS Code 332722489) = 3%
    - Urethane and other foam products (NAICS Code 326150P) = 9%
- Blade assembly labor cost
    - General inflation index
- Hub
    - Ductile iron castings (NAICS Code 3315113)
- Pitch mechanisms and bearings
    - Bearings (NAICS Code 332991P) = 50%
    - Drive motors (NAICS Code 3353123) = 20%
    - Speed reducer, i.e., gearing (NAICS Code 333612P) = 20%
    - Controller and drive - industrial process control (NAICS Code 334513) = 10%
- Low-speed shaft
    - Cast carbon steel castings (NAICS Code 3315131)
- Bearings
    - Bearings (NAICS Code 332991P)
- Gearbox
    - Industrial high-speed drive and gear (NAICS Code 333612P)
- Mechanical brake, high-speed coupling, etc.
    - Motor vehicle brake parts and assemblies (NAICS Code 3363401)
- Generator (not permanent-magnet generator)
    - Motor and generator manufacturing (NAICS Code 335312P)
- Variable-speed electronics
    - Relay and industrial control manufacturing (NAICS Code 335314P)
- Yaw drive and bearing
    - Drive motors (NAICS Code 3353123) = 50%
    - Ball and roller bearings (NAICS Code 332991P) = 50%
- Main frame
    - Ductile iron castings (NAICS Code 3315113)

- Electrical connections
    - Switchgear and apparatus (NAICS Code 335313P) = 25%
    - Power wire and cable (NAICS Code 3359291) = 60%
    - Assembly labor (general inflation index) = 15%
- Hydraulic system
    - Fluid power cylinder and actuators (NAICS Code 339954)
- Nacelle cover
    - Fiberglass fabric (NAICS Code 3272123) = 55%
    - Vinyl type adhesives (NAICS Code 32552044) = 30%
    - Assembly labor (general inflation index) = 15%
- Control, safety system
    - Controller and drive - industrial process control (NAICS Code 334513)
- Tower
    - Rolled steel shape manufacturing - primary products (NAICS Code 331221)
- Foundations
    - Other heavy construction (NAICS Code BHVY)
- Transportation
    - General freight trucking, long-distance, truckload (NAICS Code 335312P)
- Roads, civil works
    - Highway and street construction (NAICS Code BHWY)
- Assembly and installation
    - Other heavy construction (NAICS Code BHVY)
- Electrical interface and connections (cost established based on transformer at 40%)
    - Power and distribution transformers (NAICS Code 3353119) = 40%
    - Switchgear and apparatus (NAICS Code 335313P) = 15%
    - Power wire and cable (NAICS Code 3359291) = 35%
    - Assembly labor (general inflation index) = 10%
- Permits, engineering
    - General inflation index
- Levelized replacement
    - General inflation index
- Operations and maintenance
    - General inflation index
- Land lease
    - General inflation index

Specific offshore categories include the following:

- Marinization
    - General inflation index
- Offshore warranty premium
    - General inflation index
- Monopole foundation (pile driven tower)
    - Other heavy construction (NAICS Code BHVY)
- Offshore port and staging equipment
    - Other heavy construction (NAICS Code BHVY)

- Offshore site preparation (scour protection)
    - Other heavy construction (NAICS Code BHVY)
- Offshore LRC
    - General inflation index
- Offshore O&M
    - General inflation index
- Offshore personnel access equipment
    - General inflation index

The actual commodity cost factors are developed by extracting PPI codes from the Bureau of Labor Statistics data bases for the PPIs for the range of dates of interest. As the baseline costs models are primarily based on September 2002, comparing the September 2002 index for each category with the index for a later month and year will provide the user with the proper escalation factor. This PPI data can be found at http://www.bls.gov/ppi/. The PPI numbers are updated monthly and allow adjustments to cost on a monthly basis for comparison. Using this method, it is only possible to project cost from 2002 to the present. The model does not provide for any attempt at projecting commodity costs into the future. The General Inflation index identified here is based on the Gross Domestic Product. The GDP numbers are updated yearly. As additional information is obtained, these breakdowns and NAICS assignments may be adjusted.

3.4 Component Formulas

Notice: Unless otherwise noted, all dimensions are in meters and all masses are in kilograms. The outputs of all formulas will be in 2002 dollars, unless otherwise noted. An escalation can then be applied using the PPIs or GDP, as earlier described.

3.4.1 Land Based

3.4.1.1 Blades

Blade Mass - The blade mass relationships were developed using WindPACT scaling study designs [2, 6]. The WindPACT static load design was also used by TPI Composites in their blade cost scaling study [10]. The static load design used International Electrotechnical Commission (IEC) Class I wind conditions, while the WindPACT baseline designs used IEC Class II wind conditions. Industry data compare well with the WindPACT baseline mass scaling relationship. It appears that typical, 2002 technology blades follow the WindPACT baseline design. LM Glasfiber has a new line of blades that take advantage of a lower-weight root design (http://www.lmglasfiber.com/Products/Wing%20Overview/2000-5000.aspx). Carbon is included in the 61.5-m blade, but apparently it is not included in the other two, lower-weight blades. TPI performed an innovative blade design study that used several technology improvements to reduce blade weight. These designs were based on an IEC Class III wind condition, and the resulting weight is slightly lower than the commercially available LM blade of comparable length. The TPI study produced two blade designs using flat back airfoils: one was all fiberglass and the other included a carbon fiber spar. The study also developed two root designs: one used 120 studs and the other used 60 T-bolts. The four permutations of blade shell and root design result in blades of similar mass and cost. The use of carbon has not been isolated from other blade improvements, such as root design and airfoil selection. At this time, only one "advanced" blade curve seems appropriate, and this curve represents combinations of technology enhancements that may or may not include carbon. However, at some blade length, these improvements must include carbon to provide the necessary stiffness to avoid extreme blade deflection. This length is not yet identified. Also, the advanced blade technology should not be used for rotors less than 100 m in diameter. The baseline blade mass relationship was selected to follow the WindPACT baseline design curve; the advanced blade mass relationship was selected to follow the LM Glasfiber design curve. The WindPACT final designs from the rotor study [6] indicate that even greater mass reduction as a function of blade length is achievable. Figure 1 shows the results of each of these studies.

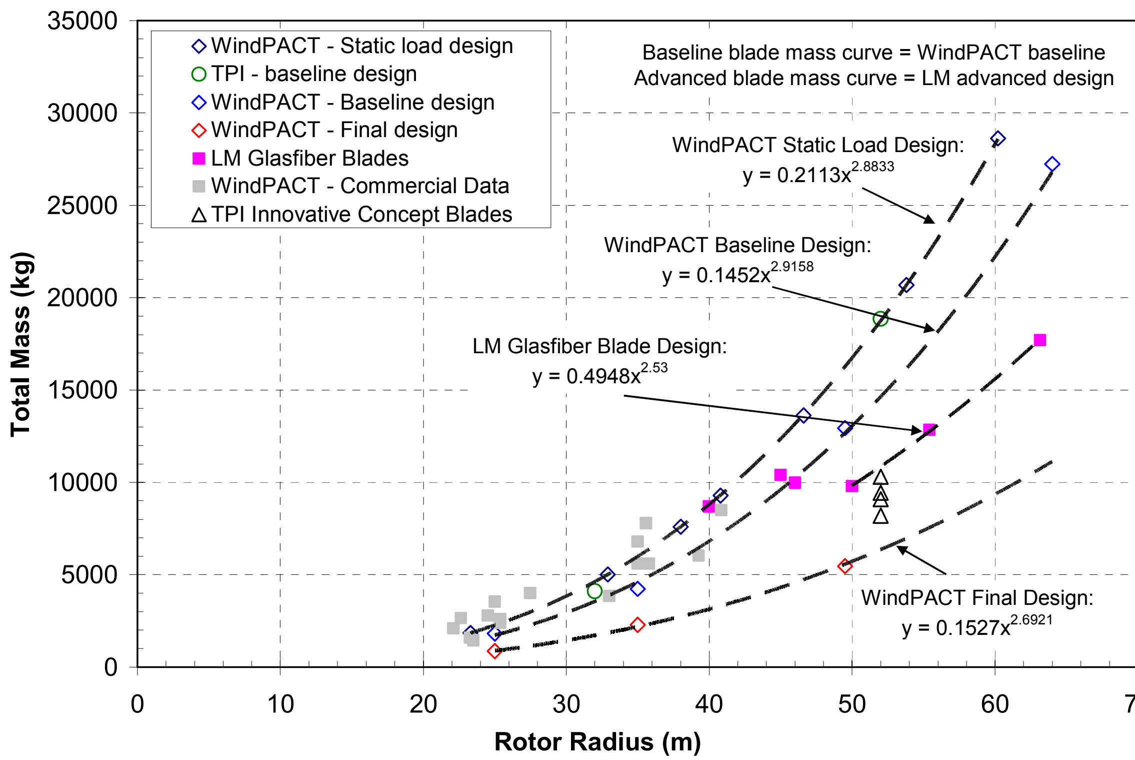

Figure 1. Blade mass scaling relationship.

Baseline: mass = $0.1452 * R^{2.9158}$ per blade
Advanced: mass = $0.4948 * R^{2.53}$ per blade
where R = rotor radius

Blade Cost - The blade costs were developed using the TPI blade cost scaling report [10]. This study investigated the scaling effects of materials, labor, profit & overhead, other costs such as tooling, and transportation. Because this cost model does not include transportation of the blades in the turbine capital cost, the transportation portion of blade cost estimated by TPI was excluded. It was assumed that the profit, overhead, and other costs were a percentage of the material and labor costs. On average, this amounted to 28% over all blade lengths studied. The blade cost was then computed as the sum of the material costs and labor costs, divided by (1 - 0.28) such that the other costs were maintained at 28% of the total blade cost. It was assumed that the labor costs would scale the same for the baseline blade and for the advanced blade. Two cost curves were created for the blade materials, representing the baseline design and the advanced design. A linear relationship between cost and R^3 was developed for the blade material cost to minimize deviation in the total blade cost curve fit. It was assumed that the advanced blade cost would scale with the baseline cost. Although the mass curves scale differently between the baseline and advanced blades, this simplifying assumption was made because the baseline cost did not scale exactly the same as the mass. The cost estimate for the advanced blade consists of the average of the four cost estimates for the four different blade designs from the TPI innovative study. Because we lacked cost data for the advanced blade designs, the scaling was assumed to follow the baseline blade material cost. Note that the advanced blade cost is not in any way related to the advanced blade mass based on LM Glasfiber These cost scaling relationships are shown in Figure 2 with the WindPACT rotor study cost for comparison.

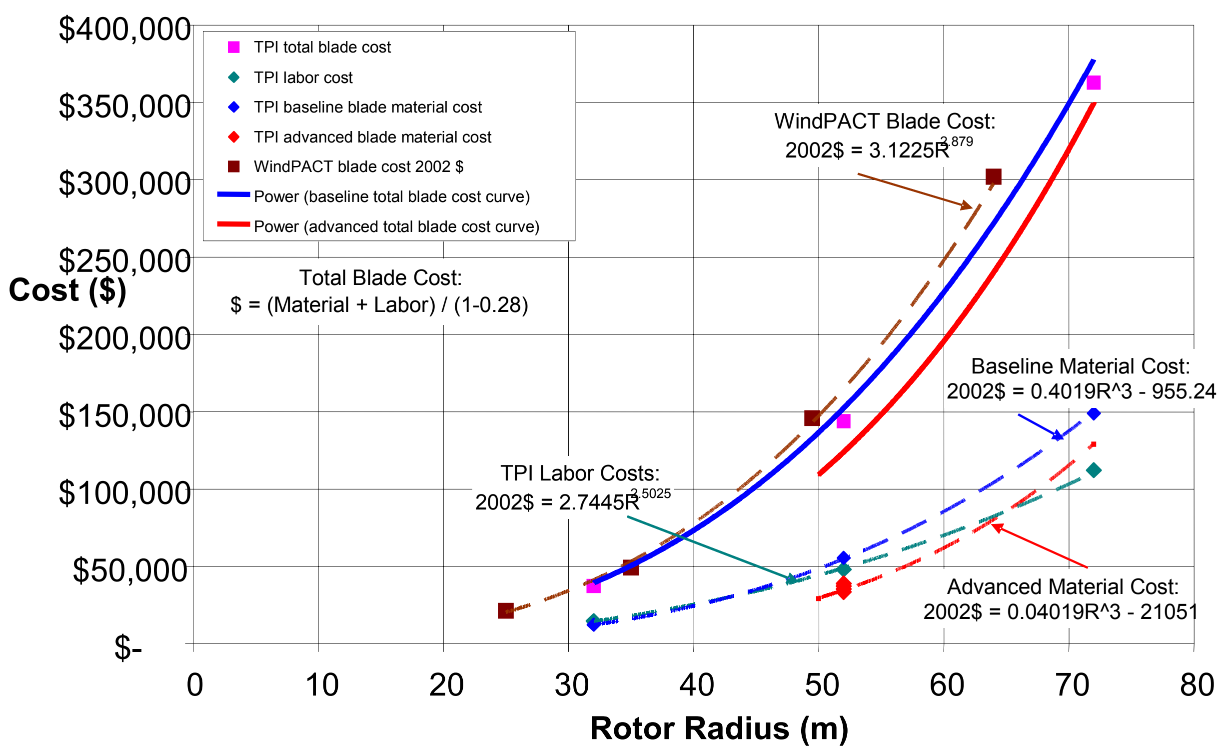

Figure 2. Blade cost scaling relationship (per blade).

Cost = (material cost + labor cost)/(1 - 0.28)
Baseline: cost = $[(0.4019 * R^3 – 955.24) * BCE + 2.7445 * R^{2.5025}GDPE]/(1 - 0.28)$ per blade
Advanced: cost = $[(0.4019 * R^3 – 21051) * BCE + 2.7445 * R^{2.5025}GDPE]/(1 - 0.28)$ per blade
where R = rotor radius, BCE = blade material cost escalator, GDPE = labor cost escalator

Cost Escalation Methodology - In the TPI cost scaling study [10], the blade material components were presented for the three blade lengths studied. The average composition was determined and grouped into fiberglass, resin & adhesive, core, and studs corresponding to NAICS industry codes. The TPI innovative blade design study [11] used costs in 2003 dollars. The blade composition was also presented for the four advanced blade designs, but for the escalation methodology only the two fiberglass blades were examined. Using the blade material composition and the four NAICS codes, the blade costs were deescalated to 2002 dollars to determine the blade material cost scaling relationship. The cost model output, which allows the user to specify the output dollar year, is computed using the formula above. The blade material cost is escalated based on the four primary components: fiberglass, resin & adhesive, core, and studs. The baseline blade is assumed to be composed of 60% fiberglass, 23% vinyl adhesive, 8 % studs, and 9% core material. The advanced blade is composed of 61% fiberglass, 27% vinyl adhesive, 3% studs, and 9% core material. In the equations above, the labor cost is escalated with the GDP, and the blade material cost is escalated with the composite escalator depending on the technology.

3.4.1.2 Hub

Development of a scaling formula for hubs began with the WindPACT rotor design study [6]. These data were further augmented by data from industry Web sites and LWST project reports. A revised scaling curve was developed using hub mass as a function of a single blade mass. The revised formula is:

Hub mass = 0.954 * (blade mass/single blade) + 5680.3

Hub cost = hub mass * 4.25 [6]

3.4.1.3 Pitch Mechanisms and Bearings

The pitch mechanisms model began with the WindPACT rotor design study data and were augmented with other available industry data and data from LWST reports. The bearing mass was calculated as a function of the blade mass for all three blades. Actuators and drives were estimated as 32.8% of the bearing mass + 555 kg.

Total Pitch Bearing Mass = .1295*total blade mass(three blades) +491.31
Total Pitch System Mass = (Total Pitch Bearing Mass * 1.328) + 555

Cost of the pitch bearings was estimated as a function of the rotor diameter. The pitch housing and actuator cost was estimated as 128% of the bearing cost.

Total pitch system cost (three blades)

$$= 2.28 * (.2106 * \text{Rotor Diameter}^{2.6578})$$

3.4.1.4 Spinner, Nose Cone

The spinner (nose cone) was not calculated independently in the WindPACT rotor study, so a new formula was derived, primarily from data in WindPACT drivetrain and LWST reports, augmented with data from the Advanced Research Turbine at the National Wind Technology Center.

Nose cone mass = 18.5 * rotor diameter – 520.5

Nose cone cost = nose cone mass * 5.57

3.4.1.5 Low-Speed Shaft

Low-speed shaft mass and cost were derived based on rotor diameter. All data were taken from the WindPACT rotor study. Several alternative drive train designs do not use independent low-speed shafts, so no low-speed shaft data are calculated in developing cost and mass data for direct drive, single-stage drive, or multi-generator drives.

Low-speed shaft mass = 0.0142 * rotor diameter $^{2.888}$

Low-speed shaft cost = 0.01 * rotor diameter $^{2.887}$

3.4.1.6 Main Bearings

The WindPACT main bearing mass and cost as reported on page 19 of the original WindPACT rotor design study report was stated incorrectly. This was corrected and reissued in April of 2006. The formula as stated in the revised report was used for this calculation. It is a function of the rotor diameter.

Bearing mass = (rotor diameter * 8/600 - 0.033) * 0.0092 * rotor diameter $^{2.5}$

The bearing housing mass was assumed to be equal to the bearing mass.

Total bearing system cost = 2 * bearing mass * 17.6 [6]

3.4.1.7 Gearbox

Gearboxes and generators are perhaps the most complicated components to predict a mass and cost for. There are a range of designs and a myriad of ways in which to configure them. This work assumes four basic designs, all studied in detail in the two WindPACT drivetrain studies. The four designs covered in this model include a three-stage planetary/helical gearbox with high-speed generator, single-stage drive with medium-speed generator, a multi-path drive with multiple generators, and a direct drive with no gearbox. The primary source for information for the three-stage planetary/helical is the WindPACT rotor study, with costs adjusted from additional information in the two WindPACT advanced drivetrain studies [7, 8]. Data for the remaining three design types come primarily from the drivetrain studies and are adjusted for data from industry and LWST reports, where available. The mass for gearboxes is scaled based on the low-speed shaft torque and thus adjusts for differences in rotor diameter and tip speed. The cost is a function of machine rating in kW.

Three-Stage Planetary/Helical

Mass = 70.94 * low-speed shaft torque $^{0.759}$

Total Cost = 16.45* machine rating $^{1.249}$

Single-Stage Drive with Medium-Speed Generator

Mass = 88.29 * low-speed shaft torque $^{0.774}$

Total Cost = 74.1 * machine rating $^{1.00}$

Multi-Path Drive with Multiple Generators

Mass = 139.69 * low-speed shaft torque $^{0.774}$

Total Cost = 15.26 * machine rating $^{1.249}$

Direct Drive

The direct-drive approach has no gearbox.

3.4.1.8 Mechanical Brake, High-Speed Coupling, and Associated Components

Brake cost is estimated as a function of machine rating. This was developed from the WindPACT rotor study cost data, converted to a function based on machine rating. Mass is back calculated based on $10/kg [8].

Brake/coupling cost = 1.9894 * machine rating - 0.1141

Brake/coupling mass = (brake coupling cost/10)

3.4.1.9 Generator

There are a wide range of possible generator designs. For this model, these designs are limited to high-speed wound rotor designs used with high-speed gearboxes, and permanent-magnet generators used with single-stage gearboxes, multi-generator gearboxes, and direct drive. Data for these designs were extracted primarily from the WindPACT rotor study and the two WindPACT drivetrain studies. These data were cross-checked with other data where available, such as the Controls Advanced Research Turbine at the National Wind Technology Center. Generator mass calculations for high-speed wound rotor, medium-speed permanent-magnet, and multi-generator designs were based on machine power rating in kW. They were each assumed to follow the same power law curve. The direct-drive mass was based on low-speed shaft torque. All cost data are a direct function of machine rating.

Three-Stage Drive with High-Speed Generator

Mass = 6.47 * machine rating $^{0.9223}$

Total Cost = machine rating * 65

Single-Stage Drive with Medium-Speed, Permanent-Magnet Generator

Mass = 10.51 * machine rating $^{0.9223}$

Total Cost = machine rating * 54.73

Multi-Path Drive with Permanent-Magnet Generator

Mass = 5.34 * machine rating $^{0.9223}$

Total Cost = machine rating * 48.03

Direct Drive

Mass = 661.25 * low-speed shaft torque $^{0.606}$

Total Cost = machine rating * 219.33

3.4.1.10 Variable-Speed Electronics

All designs in this model are assumed to have a power converter capable of handling full power output. This allows both variable-speed operation as well as "low-voltage ride through" when properly programmed. All converters are calculated as a function of rated machine power. A number of alternative approaches to power converters are possible, but they require additional study and modeling before incorporation into this tool. Mass for this component is not calculated, though in some designs a portion or all of the converter could be in the nacelle impacting structural and dynamics design issues.

Total Cost = machine rating * 79 [7]

3.4.1.11 Yaw Drive and Bearing

Yaw bearing costs were calculated using the original formula developed in the WindPACT rotor study; these were based on quotes from Avon Bearing. These calculations were sized on rotor diameter. Total yaw system cost is twice the bearing cost. Mass data in the WindPACT study were based on calculated moments. These moments were calculated using a structural dynamics program such as Fatigue, Aerodynamics, Structures, and Turbulence (FAST) or Automated Dynamic Analysis of Mechanical Systems (ADAMS). However, since the design and cost scaling model does not have these moments available to it, the yaw bearing mass was calculated as a function of rotor diameter, taken from the data supplied in the WindPACT rotor study. The bearing housing was estimated as 60% of the bearing mass.

Total yaw system mass = 1.6 * (0.0009 * rotor diameter $^{3.314}$)

Total Cost = 2 * (0.0339 * rotor diameter $^{2.964}$)

3.4.1.12 Mainframe

The mainframe cost is calculated as a function of rotor diameter. Platforms and railing are calculated on $/kg. Data for these relationships were extracted primarily from the WindPACT rotor study and the two WindPACT drivetrain reports. Minor adjustments were made where other industry or LWST data were available. Mainframe mass and cost are functions of the type of drive train. Each drive train design distributes its load in a different manner and will have a different length. Mass and cost for the mainframe are calculated as a function of the rotor diameter. The mass functions for all three designs were assumed to follow the same power law function, which is slightly less than a square relationship. It is assumed that designers find more creative ways to handle the loads as size increases keeping this from following a cubic relationship as might seem intuitive. Additional mass of 12.5% is added for platforms and railing. Costs for the additional platforms and railing are calculated on a $/kg basis.

Three-Stage Drive with High-Speed Generator

Mainframe mass = 2.233 * rotor diameter $^{1.953}$

Mainframe cost = 9.489 * rotor diameter $^{1.953}$

Single-Stage Drive with Medium-Speed, Permanent-Magnet Generator

Mainframe mass = 1.295 * rotor diameter $^{1.953}$

Mainframe cost = 303.96 * rotor diameter $^{1.067}$

Multi-Path Drive with Permanent-Magnet Generator

Mainframe mass = 1.721 * rotor diameter $^{1.953}$

Mainframe cost = 17.92 * rotor diameter $^{1.672}$

Direct Drive

Mainframe mass = 1.228 * rotor diameter $^{1.953}$

Mainframe cost = 627.28 * rotor diameter $^{0.85}$

Platforms and Railings

Platform and railing mass = 0.125 * mainframe mass

Platform and railing cost = mass * 8.7

3.4.1.13 Electrical Connections

Electrical connections, including switchgear and any tower wiring, were taken from the WindPACT rotor study and are calculated as $40/kW of machine rating. No adjustment was made to these data.

Electrical connection cost = machine rating * 40 [6]

3.4.1.14 Hydraulic and Cooling Systems

Hydraulic and cooling system estimates were taken from LWST reports. Mass is a function of machine rating in kW. Cost is a function of machine rating times $/kW.

Hydraulic, cooling system mass = 0.08 * machine rating

Hydraulic, cooling system cost = machine rating * 12

3.4.1.15 Nacelle Cover

Nacelle cover costs were derived from WindPACT rotor study data combined with WindPACT drive-train study and LWST report data. A single function was derived for all drivetrain configurations, as data were too scarce to develop individual formulas for different drivetrain configurations. The calculations are a function of machine rating in kW. Nacelle cover mass was derived from Nacelle cover cost. The cost per kg for the nacelle cover was taken from the WindPACT rotor study.

Nacelle cost = 11.537 * machine rating + 3849.7

Nacelle mass = nacelle cost / 10 [6]

3.4.1.16 Control, Safety System, Condition Monitoring

WindPACT studies identified a cost of $10,000 for control, safety, and condition monitoring systems for a 750-kW turbine. A slight scaling factor was applied for larger machines to take into account additional wiring and sensors. However, these data were based on 1999 designs. During the early 2000s, operators realized the value of additional sensing and monitoring systems. To take this into account, this number for land-based systems was increased to $35,000 in 2002 dollars, regardless of machine size or rating. Offshore systems are expected to be more sophisticated and extensive. For offshore systems, this number was raised to $55,000, regardless of machine size or rating. These rough estimates were based on discussions with industry development partners.

3.4.1.17 Tower

The tower mass and cost scaling relationships were based primarily on the WindPACT studies [3, 6]. All towers discussed here are steel tubular towers. The tower mass is scaled with the product of the swept area and hub height, as shown in Figure 3. Given any turbine diameter, hub height, and tower mass, a comparison can be made between steel tubular towers. The initial WindPACT scaling studies provide a crude estimate of tower mass based on the most extreme base moment. Turbines are designed for trade-offs between buckling and overturning moment for a more precise set of load conditions. Fatigue loads are also estimated. The WindPACT rotor study baseline design [6] uses conventional technology circa 2002 and scales it up. The WindPACT rotor study final design [6] uses advanced technologies including tower feedback in the control system, flap-twist coupling in the blade, and reduced blade solidity in conjunction with higher tip speeds. These final designs show the trends for future design.

Commercial turbines were compared with these WindPACT scaling relationships. This comparison assumes that the different rotors have similar thrust coefficients. The tower mass, provided by the manufacturers, is based on a design for the variety of design conditions and tradeoffs for turbines with different rotors and hub heights. The WindPACT rotor study baseline design scaling relationship represents most commercial turbines today, but it may be somewhat conservative. The WindPACT rotor study final design scaling relationship may be achievable through technology innovation, but it results in mass projections much lower than what is commercially available today. The impact of towers with base diameters of greater than 4.3 meters is generally reflected in the transportation and erection costs, but these functions should be used carefully when looking at towers of much greater than 80 meters, as design tradeoff for transportation and erection will have a major impact on design.

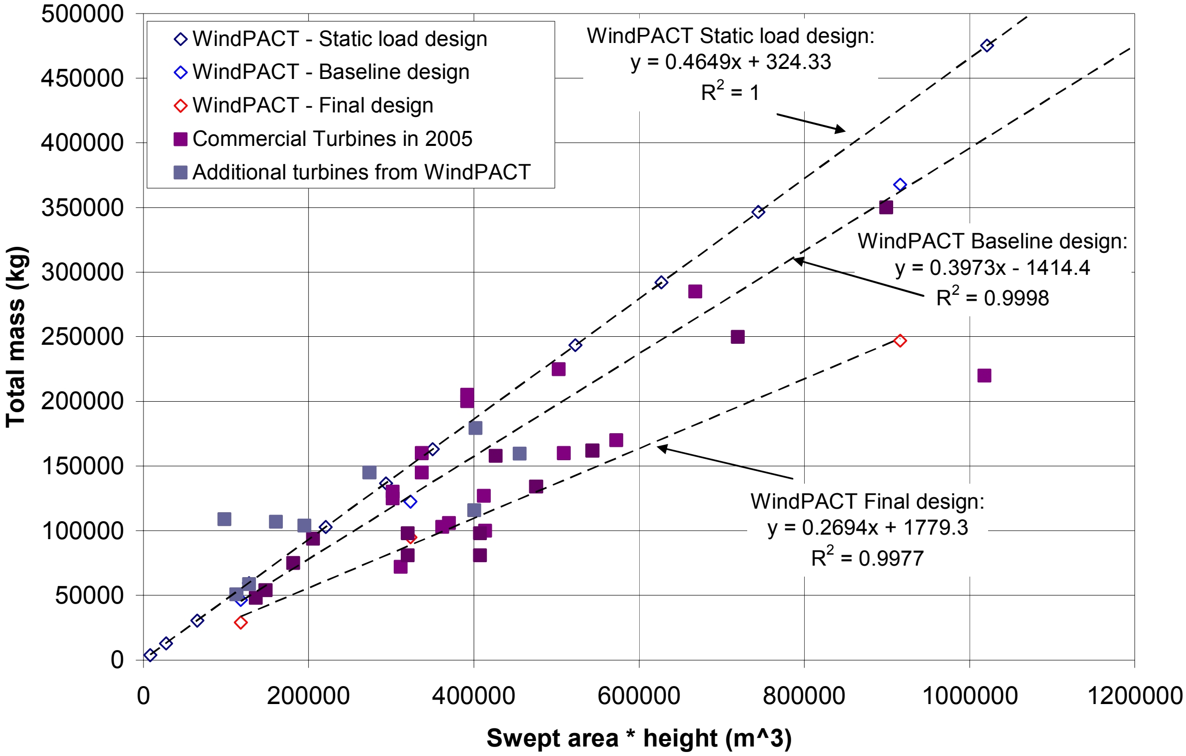

Figure 3. Tower mass scaling relationship.

Baseline: mass = 0.3973 * swept area * hub height – 1414
Advanced: mass = 0.2694 * swept area * hub height + 1779

WindPACT cost of steel was $1.50/kg in 2002 dollars. The tower cost is computed as follows:

Total Cost = mass * 1.50

The cost is then escalated using the PPI to the appropriate year dollars.

3.4.1.18 Foundation

Foundation estimates are based solely on the WindPACT rotor study report. Foundations used to develop these estimates were primarily based on a design by Patrick and Henderson that can generally be described as a hollow drilled pier. These foundations are approximately the diameter of the tower base and may be 30 or more feet in depth. A number of alternate foundation designs are possible that will vary based on local soil conditions. No attempt has been made here to try to evaluate different design approaches. Foundations were scaled as a function of hub height times rotor swept area, which is directly proportional to the tower overturning moment. No mass data were calculated for the foundation.

Foundation cost = 303.24 * (hub height * rotor swept area) $^{0.4037}$

3.4.1.19 Transportation

The transportation estimate was taken from the WindPACT logistics study [3] and is a function of machine rating. These costs reflect the large cost increases required for 3- and 5-MW turbines if transported and erected onshore.

Transportation cost factor $/kW =

$$1.581E\text{-}5 * \text{machine rating}^2 - 0.0375 * \text{machine rating} + 54.7$$

Transportation cost = machine rating * cost factor above

3.4.1.20 Roads, Civil Work

Estimates for roads and civil work were taken directly from the WindPACT logistics study [3]. These estimates include modifications to road widths and crane pads to handle larger machines. Cost is a function of machine rating in kW.

Roads, civil work cost factor $/kW =

$$2.17E\text{-}6 * \text{machine rating}^2 – 0.0145 * \text{machine rating} + 69.54$$

Roads, civil work cost = machine rating * cost factor above

3.4.1.21 Assembly and Installation

Data for this relationship come from the WindPACT rotor study, which developed a formula based on $/kW of machine rating. This formula was not used. Instead, it was found that a relationship based on hub height times rotor diameter gave almost a straight line relationship. Though both of these relationships give a close-to-linear relationship, it is believed that a function that takes into account the physical size of the largest components will give a more direct relationship as these components change in size. This relationship was used in the model. It is probable that some type of step function will be more appropriate in the future to take into account changes in requirements for different crane models as tower height increases. The data to develop such a function may be available in the WindPACT Logistics Study [3], but further evaluation is needed.

Assembly and installation = $1.965 * (\text{hub height} * \text{rotor diameter})^{1.1736}$

3.4.1.22 Electrical Interface/Connections

Electrical interface covers the turbine transformer and the individual turbine’s share of cables to the substation. These data originally came from the WindPACT balance-of-station study [5] and were used in this model as originally derived.

Electrical interface/connection cost factor $/kW =

$$3.49E\text{-}6 * \text{machine rating}^2 – 0.0221 * \text{machine rating} + 109.7$$

Electrical interface/connection cost = machine rating * electrical cost factor above

3.4.1.23 Engineering, Permits

Engineering and permits covers the cost of designing and permitting the entire wind facility, allocated on a turbine-by-turbine basis. These costs are highly dependent upon the location, environmental conditions, availability of electrical grid access, and local permitting requirements. The formulas provided here were first derived from the WindPACT balance-of-station cost study [5] and were used in this model without modification.

Engineering, permits cost factor $/kW =
9.94E-4 * machine rating + 20.31

Engineering, permits cost = machine rating * engineering, permits cost factor above

3.4.1.24 Levelized Replacement Cost

Levelized replacement cost is a sinking fund factor to cover long-term replacements and overhaul of major turbine components, such as blades, gearboxes, and generators. The WindPACT rotor study originally developed this number from a Danish study. Additional cross-checking of this with limited U.S. experience lowered this number for use in the LWST Project. The LWST factor is used in this model. This term is based on $/kW/year. Work is under way to develop more sophisticated models of this function based on actual wind farm experience in the United States. However, as of this writing, no improved estimate is available.

LRC cost factor = $10.7/kW machine rating

Annual LRC = machine rating * LRC cost factor above

3.4.1.25 Operations and Maintenance

O&M cost covers the day-to-day scheduled and unscheduled maintenance and operations cost of running a wind farm. Different wind turbine designs, due to varying complexity, may have different O&M costs. However, many new configurations have insufficient operating experience to extract a meaningful O&M cost history. Industry cost estimates range from 0.5¢/kWh to more than 1¢/kWh. The LWST project in 2002 recommended a cost factor of 0.7 ¢/kWh, regardless of machine size or configuration. This allowed studies to determine the impact of other technology elements on COE without factoring in O&M cost impacts, which were extremely difficult to estimate at the time. New work is under way to evaluate O&M costs based on actual wind farm experience in the United States. Preliminary results from these studies indicate that the cost per kWh can change significantly between installations of the same machine based on wind farm size, tower height or other operational factors. This indicates that a fixed cost per kWh for O&M is inappropriate. Work is underway to better quantify these effects and build the varying factors into the model. Until this work is concluded, the fixed cost of $0.007kWh is being retained as the best estimate available.

Land-based O&M cost in $ = 0.007 * AEP

3.4.1.26 Land Lease Costs

Wind turbines normally pay lease fees for land used for wind farm development.. This cost is principally based upon the land used by the turbine. The factors applied in different wind farm developments vary widely depending on the wind class of the particular site, the nature and value of the land, and the potential market price for the wind. No single number or model is currently available to predict these costs based on turbine rating, size, or wind class. The number used in this model is based on a cost kWh of production making it highly variable with wind class and machine performance. This cost was proposed for the LWST Project and defined in the report on pathways analysis [8]. While the use of a cost kWh appears inappropriate in the long run, this number is currently frozen at $0.00108/kWh until better information is available.

LLC cost = $0.00108/kWh * AEP

3.4.2 Offshore Elements

The turbine cost and scaling model was originally developed for land-based technology. The need to evaluate offshore wind technology led to expanding the model. The majority of cost for land-based components will not be affected by offshore designs, so the models proposed here for turbine subsystems and components are believed to be appropriate for offshore. Some of the cost factors used for both land-based and offshore differ for the two different types of installation. If there are differences, they are noted below. A few additional elements of cost specific for offshore installation and preparation must be added. These factors are discussed below. The data for deriving these factors are extremely meager and are primarily based on magazine articles or private industry communications converted to scaling factors. Where data are public domain, they have been referenced. At this time, the model only handles shallow water installations. In most cases, these numbers are very rough estimates, and each area is one in which more in-depth research is required for the development of offshore technology. Data provided for the Shallow Water installation here are primarily based on a 500 MW wind farm using 167, 3 MW turbines. These machines would have a rotor diameter of 90 meters and a hub height of 80 meters. This wind farm would be installed in 10 meter water depth 5 miles from shore. Array spacing would be 7 rotor diameters by 7 rotor diameters. This is assumed to be a mature design with mature component productions. This baseline turbine and the sources of many of the factors below are described in greater detail in [13], a draft report to be published by NREL in the near future.

3.4.2.1 Marinization

The Marinization component covers special preparation for all components to increase their survivability in the extremes of an offshore ocean environment. These preparations include special paints and coatings, improved seals for gearboxes, generators, electrical components, and electrical connections. It is calculated as a percentage of all turbine costs from the tower up. The percentage used in the current model was derived from data published in a range of European journals. These numbers suggest marinization factors of between 10% and 15% [10].

A number of 13.5 % has been chosen for the baseline model. This is a rough estimate and may vary with the design.

Marinization cost = 13.5% of turbine and tower costs.

3.4.2.2 Offshore Support Structure

Land-based turbines are normally installed on concrete foundations. Offshore turbines must be attached to a form of foundation that extends from sea bed to sea level so that the tower can be affixed atop it. These foundations can take several forms, but the most often used is a driven pile (a steel pile driven into the sea bed) that protrudes above the water line. The wind turbine tower is bolted to the top of this structure. The cost for installing such a pile is normally significantly greater than the basic concrete footers used for a land-based turbine. Costs in this model were derived from a University of Massachusetts study [11], augmented with private industry communications expressed as a function based on machine rating. Effort is under way to develop engineering-based models for these structures.

Offshore support structure cost = 300 * machine rating

Cost is in 2003 dollars.

3.4.2.3 Offshore Transportation

There are two elements of transporting an offshore wind turbine. One element is to get the turbine components to the port staging and assembly area. The second is to get the assembled turbine to the installation site. This second of these cost elements is covered in the offshore installation cost (see Section 3.4.2.5). The cost element in the offshore transportation category (somewhat of a misnomer) covers only the cost of bringing the components to the assembly site onshore. The costs for 3 to 5 MW turbines show a significant increase over smaller machines due to the premiums for moving such large structures over the road or by rail to wind farm sites in the central plains. These costs may be significantly reduced by locating fabrication facilities close to the port and staging areas. For the estimates in this model, the scaling formulas developed in the WindPACT studies were used. These are the same factors as described in Section 3.4.1.19 above.

Offshore transportation cost factor \$/kW =

$$1.581E\text{-}5 * \text{machine rating}^2 - 0.0375 * \text{machine rating} + 54.7$$

Offshore transportation cost = machine rating * cost factor above

3.4.2.4 Port and staging equipment

Offshore wind installations require unique facilities to install and maintain operation. Special ships and barges are needed for installing piles, setting towers and turbines, laying underwater electrical lines, and providing ongoing servicing. Long-term data on these costs are still sketchy. The costs available to date are based on private industry communications converted to a scaling factor based on machine rating, and cross-checked with some data published in European journals. Little hard detailed industry data are available.

Port and staging equipment = 20 * machine rating

3.4.2.5 Offshore Turbine Installation

In the future, to help lower costs, specialized equipment should be developed for installing turbines on piles or floating platforms. Ocean-going cranes and special barges capable of station keeping in currents and winds will be needed to allow erection of the turbine. An alternative to special ships with cranes will be land-based cranes loaded onto special barges and maneuvered into place for installation. Regardless, it is expected that the installation of very large offshore turbines will be more cost effective in the long run than similar land-based installations, due to the greater hauling capacity of barges and lifting capacity of offshore crane equipment. For shallow water installation, this cost element also includes transport of the turbine from shore to the installation site. In the future a separate cost element will need to be developed for transport of turbines to sites further offshore. Costs in this model are once again based on private industry communications converted to a scaling factor according to machine rating.

Offshore turbine installation = 100 * machine rating

Cost is in 2003 dollars.

3.4.2.6 Offshore Electrical Interface and Connection

In most cases, offshore wind installations will require their own electrical transmission system to bring the turbine power to shore. In addition to the connections to shore, underwater electrical cables will be required to go from turbine to turbine to gather the turbine power. Some forms of redundancy may also be considered for such installations. Because few such large-scale installations have been built, very little detailed information for this cost element has been developed, though a modeling effort is under way. The costs in this element includes the cost of cabling between turbines and the cable to the grid interconnect at the shore. Costs in this model are based on calculations and data developed for the first DOE offshore white paper [12]. The cost for cable and other equipment for this calculation came from an internal DOE/NREL study and a report that has not been published. This number should be used with significant care, as it is calculated specifically based on a distance to shore of 5 miles, a water depth of 10 meters, and an array spacing of 7 by 7. Changes to any of these factors would be expected to change this number significantly, as the electrical cost factor is primarily driven by cable cost. Work is underway to develop an improved model that will adjust electrical interconnect costs based on all of these factors. It is hoped that this work will be completed in 2007.

Offshore electrical interface and connection cost = 260 * machine rating

Cost is in 2003 dollars.

3.4.2.7 Offshore Permits, Engineering, and Site Assessment

Permitting, developing detailed engineering plans, and measuring wind conditions for an offshore site are all more complicated and time consuming than for a land-based site, as there is a minimum of experience developed for the process. Initial estimates for these costs are quite high, as the first offshore wind farms developed have had to go through an extensive developmental processes. The costs in this model are based on private industry communications converted to a $/kW scaling factor. During the first of such installations in the United States, these costs are expected to fluctuate as new agencies and states become involved in the process. However, over time, they would be expected to come down as the process is better understood and streamlined.

Offshore permits, engineering, and site assessment cost = 37 * machine rating

Cost is in 2003 dollars.

3.4.2.8 Personnel Access Equipment

Wind turbines located offshore must be accessed from marine vessels, small boats, or helicopters for servicing. The environment will present many hazards for those performing this service. To improve the safety for these operations, special personnel access equipment will be required. Aside from typical equipment such as for fall protection, servicing may require special boat access ramps or docking equipment, lifesaving equipment located at each turbine, special tool lifts, and emergency survival equipment in case service personnel are stranded at a turbine. The full scope of these requirements will be developed over time, as additional facilities are developed and the needs identified. The initial estimates in this document were developed from private industry communications and cross-checked with such published industry numbers when available.

Personal access equipment = $60,000 /turbine (regardless of turbine rating)

Cost is in 2003 dollars.

3.4.2.9 Scour Protection

Shallow-water turbines will be mounted on towers or piles that are fixed to the ocean bottom. These foundations may be driven piles or large concrete footers sitting on the bottom. In any case, currents swirling around the base of the footing will have a tendency to scour bottom material from the base, causing danger of foundation failure. To mitigate against such scouring, rip rap (graded boulder and rock) may be placed around the base to reduce the effects of such currents. Cost for this can be relatively easily estimated depending upon the level of current and the nature of the seabed. Cost estimates in this model are currently based on private industry communications converted to a scaling factor by machine rating.

Scour protection = 55 * machine rating
Cost is in 2003 dollars.

3.4.2.10 Surety Bond

Offshore installations, once decommissioned at the end of their lifetimes, may present long-term navigational hazards. Once developed, it is unlikely that good wind sites will be abandoned. However, there is the possibility that older foundation or support structures may need to be removed when turbines are replaced. To guarantee that funds are provided for removing these older structures, a surety bond is provided for. This is a percentage of the ICC less the offshore warranty cost.

Surety bond cost = 3% (ICC - offshore warranty cost)

3.4.2.11 Offshore Warranty Premium

Offshore turbines operate in an extreme environment. Because of this and their remote location, many manufacturers believe that providing an adequate warranty will represent a greater risk than for land-based installations. As offshore installations become more common and operational history improves, warranty cost would be expected to be adjusted appropriately. Current warranty estimates are based on private industry communications. Additional study and experience is required to improve the current estimate.

Offshore warranty premium = 15.0% of turbine and tower cost

3.4.2.12 Offshore Levelized Replacement Cost

LRC is a sinking fund factor to cover long-term replacements and overhaul of major turbine components, such as blades, gearboxes, and generators. Offshore installations are believed to carry a higher risk of wear and damage that will require more frequent replacements and overhaul. The estimate of LRC for offshore installations has been developed based on private industry communications and converted to a scaling factor based on $17/kW.

Offshore LRC = 17 * machine rating

Cost is in 2003 dollars.

3.4.2.13 Offshore Bottom Lease Cost

As on land, the surface space a turbine occupies is not free. Someone inevitably holds the rights to the ocean floor in a particular region. Most of these rights are held by the Federal or State governments, and a cost for leasing these sites will be incurred (similar to offshore drilling leases). The cost in this model is based on the same approach as the land-based model on a fixed cost of $.00108/kWh of production. This estimate may change as a better understanding of offshore leasing arrangements is developed.

Offshore bottom lease cost = 0.00108 * AEP

3.4.2.14 Offshore O&M

Because of the extreme operating environment, the remote location, and the specialized access and servicing equipment (barges, ships, boats) needed, offshore O&M costs are expected to be much higher than those for land-based installations, at least during the early period of development. The magnitude of these costs will be a strong driver in advancements in turbine design and operational reliability. As experience and equipment improve, O&M costs will be expected to fall. For this model, initial offshore O&M costs are expected to be almost three times that of current onshore estimates. Costs are estimated on a $0.02/kWh basis.

Offshore O&M cost = 0.02 * AEP

Cost in 2003 dollars.

3.5 AEP

The AEP spreadsheet is designed to compute annual energy capture and other related factors for a wind turbine specified by certain generic input parameters. Notably, these parameters do not include blade geometry, airfoil performance, or even a Coefficient of Power (C_p) versus tip-speed-ratio (λ) curve. Only a peak C_p is given, and the λ at which it occurs. This strategy enables parametric studies around the available parameters to be completed.

The AEP spreadsheet works by dividing up the operational range into ¼ m/s bins. In each bin, necessary parameters such as hub power, drive-train efficiency, and total energy are computed. Important parameters such as energy capture and capacity factor are computed from the column totals.

3.5.1 Inputs

The inputs include the following:

- 50-m wind speed
- Weibull K parameter
- Rated power
- Rotor diameter
- Hub height
- Altitude above mean sea level
- Rotor peak Cp, which is called C_p^* below
- Tip speed ratio (λ) at which C_p^* occurs, which is called λ^* below
- Maximum rotor tip speed
- Region 2 ½ slope
- Power law shear exponent (shear)
- Three conversion efficiency constants described below

The following two parameters are specified but could be modified if desired:

- Cut-in wind speed
- Cut-out wind speed

The following image represents the top portion of the AEP spreadsheet.

	A	B	C	D	E	F	G
1	**50 m windspeed**	7.25	m/s			**P/Prated**	**Efficiency**
2	**Weibull K parameter**	2.00				0	0.0%
3	**Rated power**	1500	kW			0.05	54.5%
4	**Rotor Dia.**	70	meters			0.1	74.5%
5	**Hub height**	65	meters			0.15	81.2%
6	**Altitude**	0	meters			0.2	84.5%
7	**Rotor Cp**	0.47				0.25	86.5%
8	**Tip speed ratio for max Cp**	7				0.3	87.8%
9	**Maximum tip speed**	75	m/s			0.35	88.8%
10	**Region 2 1/2 slope**	5%				0.4	89.5%
11	**Cut-in windspeed**	3	m/s			0.45	90.1%
12	**Cut-out windspeed**	26	m/s			0.5	90.5%
13	**Power law shear exponent**	0.143				0.55	90.9%
14	**Rated RPM**	**20.46**	Okay			0.6	91.2%
15	**Air Density**	**1.225**	kg/m^3			0.65	91.4%
16	**Hub height windspeed**	**7.53**				0.7	91.6%
17	**Rated hub power**	**1621.622**	kW			0.75	91.8%
18	**Rated windspeed**	**11.39**	m/s	11.35	11.41	0.8	92.0%
19	**Conversion Efficiency**	0.02	Constant			0.85	92.1%
20		0.055	Linear			0.9	92.3%
21		0	Quadratic			0.95	92.4%
22	**Soiling Losses**	3.5%				1	92.5%
23	**Array Losses**	5.0%					
24	**Availability**	98.0%					**Regio**
25		Turbine	Weibull Cp	Weibull betz		Omega M	2.142857
26	**Energy capture (MWh/year)**	**4383.88**	**7140.71**	**9964.89**		Omega 0	2.040816
27	**Capacity Factor**	**33.36%**				Tm	756756.8
28	**Energy capture ratio**	**61.39%**				k	138475.2

3.5.2 Computations

Air density ρ (cell B15) above, at the given altitude (meters) is determined by the equation below:

$$\rho = \frac{101300 * \left[1 - \left(\frac{0.0065 * altitude}{288} \right)^{9.80665 / 0.0065*287.15} \right]}{287.15 * (288 - 0.0065 * altitude)}$$

Hub-height mean wind speed (B16) is based on the power-law exponent:

$$\overline{V} = \left(\frac{hub\ height}{50} \right)^{sheer} * 50\text{–}m\ wind\ speed$$

Rated hub power (B17) is just the hub power when the turbine is at rated power:

$$\frac{rated\ \ power}{efficiency\ at\ rated\ \ power}$$

The following image represents the bottom portion of the AEP spread sheet which contains the computation matrix that is used to develop the estimated AEP.

	A	B	C	D	E	F	G	H	I	J	K	L
50	Wind	Rayleigh Probability	Weibull Probability	Weibull Betz	Weibull Cp	Turbine Energy	Hub power	Efficiency	Turbine power	Region 2 hub Power	Region 2 1/2 hub power	Region 3 hub power
51	0.00	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0%	0.00	0.00	0.0000	3000.0000
52	0.25	0.0051	0.0037	0.0001	0.0000	0.0000	0.0000	0.0%	0.00	0.03	0.0000	3000.0000
53	0.50	0.0101	0.0079	0.0023	0.0000	0.0000	0.0000	0.0%	0.00	0.24	0.0000	3000.0000
54	0.75	0.0151	0.0123	0.0120	0.0000	0.0000	0.0000	0.0%	0.00	0.81	0.0000	3000.0000
55	1.00	0.0201	0.0168	0.0391	0.0000	0.0000	0.0000	0.0%	0.00	1.93	0.0000	3000.0000
56	1.25	0.0249	0.0213	0.0970	0.0000	0.0000	0.0000	0.0%	0.00	3.77	0.0000	3000.0000
57	1.50	0.0297	0.0259	0.2037	0.0000	0.0000	0.0000	0.0%	0.00	6.51	0.0000	3000.0000
58	1.75	0.0344	0.0305	0.3804	0.0000	0.0000	0.0000	0.0%	0.00	10.33	0.0000	3000.0000
59	2.00	0.0389	0.0350	0.6522	0.0000	0.0000	0.0000	0.0%	0.00	15.42	0.0000	3000.0000
60	2.25	0.0433	0.0394	1.0469	0.0000	0.0000	0.0000	0.0%	0.00	21.96	0.0000	3000.0000
61	2.50	0.0476	0.0438	1.5949	0.0000	0.0000	0.0000	0.0%	0.00	30.12	0.0000	3000.0000
62	2.75	0.0516	0.0481	2.3289	1.9264	1.9264	40.0920	100.0%	40.09	40.09	0.0000	3000.0000
63	3.00	0.0555	0.0522	3.2826	2.7154	2.7154	52.0503	100.0%	52.05	52.05	0.0000	3000.0000
64	3.25	0.0592	0.0561	4.4908	3.7148	3.7148	66.1774	100.0%	66.18	66.18	0.0000	3000.0000
65	3.50	0.0626	0.0599	5.9881	4.9533	4.9533	82.6540	100.0%	82.65	82.65	0.0000	3000.0000
66	3.75	0.0659	0.0635	7.8087	6.4593	6.4593	101.6608	100.0%	101.66	101.66	0.0000	3000.0000
67	4.00	0.0689	0.0669	9.9853	8.2597	8.2597	123.3786	100.0%	123.38	123.38	0.0000	3000.0000

The efficiency columns (Column G in the top portion and H in the bottom portion) are based on the concept that most losses can be fit into one of three categories:

1) Losses that are constant and independent of power level
    a. Such losses include core loss in a transformer, switching loss in a constant-switching-frequency power converter, windage losses in a constant-speed motor/generator, constant speed pumps, fans or other “hotel” loads.
    b. Constant losses are undesirable because they absorb power whenever a turbine is in operation. Permanent-magnet generators tend to have very low constant losses because they don’t require current for magnetization.
2) Losses that change linearly with power level
    a. Very few losses usually fit this category. Possibilities include a fan whose speed is proportional to temperature difference and switching loss in a converter whose switching frequency is proportional to load.
3) Losses that change with power level squared
    a. The most common term with this characteristic is copper losses at constant voltage that follow the familiar I^2R formula. Others can include lubrication losses in a variable-speed gearbox, certain other gearbox losses, and conduction losses in some switch types.
    b. Direct-drive systems might eliminate all of the quadratic losses associated with the gearbox, but they also usually have quite a bit of quadratic losses in the generator in order to keep the generator small enough to be cost competitive. Medium-voltage systems tend to reduce quadratic losses because the voltage is higher, which means that the I^2R losses are lower at the same power level.

This leads to the equation for efficiency:

$$\eta = \frac{\frac{P}{P_{rated}} - \left(Constant + Linear \cdot \frac{P}{P_{rated}} + Quadratic \cdot \left(\frac{P}{P_{rated}} \right)^2 \right)}{\frac{P}{P_{rated}}}$$

Efficiency is set to zero if there is an error in computing it, such as when power is zero.

The first computation column is the wind column (A), called "V" in the equations below.

The Rayleigh probability column (B) is only provided for reference. The formula is:

$$\frac{\pi V}{2\overline{V}^2} e^{-\frac{\pi V^2}{4\overline{V}}}$$

The next column (C) is the Weibull probability. Its formula uses the Excel Weibull function:

$$Weibull\left(V, K, \overline{V} \big/ \gamma \ln\left(1 + 1/K\right) \right)$$

The Weibull-Betz column (D) computes the binned power of a Betz turbine operating in the specified Weibull wind regime:

$$\frac{1}{2} \rho \frac{\pi D^2}{4} V^3 \cdot Weibull \cdot \frac{16}{27}$$

The Weibull C_p column (E) computes the binned power of the specified machine with its actual C_p and efficiency curve:

$$\frac{1}{2} \rho \frac{\pi D^2}{4} V^3 \cdot Weibull \cdot C_p \cdot efficiency$$

The turbine energy column (F) is the turbine power times the Weibull probability:

$$P \cdot Weibull$$

The rated wind speed is difficult to compute. Region 2 ½ is essentially a near constant speed region, which pulls the rotor off the optimal C_p - λ peak point. Since the shape of the C_p - λ curve is unavailable, an assumption is made about the wind speed at which we achieve rated power. This point is somewhere between the wind speed at which we would achieve rated power if we had no region 2 ½ at all, and a linear extrapolation of where region 2 would intersect with rated power if its slope were maintained at the value it has when it reaches region 2 ½. From some studies of blade element momentum models of large machines, we have, somewhat arbitrarily, chosen 2/3 of the distance from the first point to the second point. This can lead to incorrect answers for unusual rotor and turbine designs. There is an error cell to indicate when there is no region 2 ½, but no method is provided to detect an error when the 2/3 assumption is incorrect.

The hub power column (G) can be one of four different values:

V # cut in	0
V # rated	$\frac{1}{2}\rho\frac{\pi D^2}{4}V^3 C_p$
V > rated	$\frac{1}{2}\rho\frac{\pi D^2}{4}V_{rated}^3 C_p$
V ∃ cut out	0

Turbine power (I) is hub power times efficiency:

$$hub\ power \cdot efficiency$$

Region 2 hub power (J) is the power the rotor produces if it is always in region 2 (maximum power tracking):

$k\left(\frac{V\lambda^*}{\frac{1}{2}D}\right)^3$ where k is the variable-speed torque constant $\frac{\pi\rho D^5 C_p^*}{64\lambda^{*3}}$

Region 2 ½ hub power (K) is the power the rotor produces if it is in region 2 ½ (the linear connecting region from region 2 to region 3).

$$\frac{rated\ hub\ power - power\ at\ \omega_t}{rated\ wind\ speed - wind\ at\ \omega_t}\left(V - wind\ at\ \omega_t\right) + power\ at\omega_t$$

Region 3 hub power (L) is the rated hub power.

ω_m is the rated rotor speed.

ω_0 is the rotor speed at which region 2 hits zero torque:

$\omega_0 = \frac{\omega_m}{1 + slope}$ where *slope* is the slope in Region 2 ½.

T_m is the rated torque:

$$T_m = \frac{ratedhubpower}{\omega_m}$$

ω_t is the rotor speed at which region 2 and region 2 ½ intersect. It is derived from the quadratic equation:

$$\omega_t = -\frac{-b-\sqrt{b^2-4ac}}{2a}$$

where

$$a = k$$

$$b = -\frac{T_m}{\omega_m - \omega_0}$$

$$c = \frac{T_m \omega_0}{\omega_m - \omega_0}$$

The wind at ω_t is given by:

$$\frac{\omega_t * D}{2 * \lambda^*}$$

The power at ω_t is:

$$k\omega_t^3$$

The total turbine energy capture calculated in the top section of the spread sheet (B26) is:

$$\frac{\sum(turbineenergy)\cdot(1-soilinglosses)\cdot(1-arraylosses)\cdot(8760\cdot availability)}{4}$$

The denominator "4" is to account for the ¼ m/s wind speed bins. Weibull C_p and Weibull Betz are similarly the sums of their respective columns, each divided by 4.

Capacity factor (B27) is:

$$\frac{energycapture}{ratedpower \cdot 8760}$$

Energy capture ratio (B28) is:

$$\frac{energycapture}{Weibull\ C_p}$$

The AEP spreadsheet is designed to compute annual energy production and other related outputs when the full turbine and rotor design are not known. Only those few inputs shown above are known, and one big assumption has to be made to complete the calculations (see the discussion above about finding rated wind speed). Therefore, the results from these calculations should be treated as approximate. The ability to change the inputs and quickly calculate new values of AEP allows fast evaluation of the effect of the input parameters on AEP, but the user must take care not to trigger the error cell (no region 2 ½) or go so far off normal as to violate the 2/3 assumption in the calculation of rated wind speed.

4.0 Output Examples

Table 2 is an example of a cost estimate and COE calculation summary from a run of the cost model for the land-based 1.5-MW baseline turbine in 2005 dollars. Table 3 is an example of the cost estimate and COE calculation summary from a run of the cost model for the offshore (shallow water) 3-MW baseline turbine in 2005 dollars.

Table 2. Cost Estimate from Scaling Model: Land-Based, 1.5-MW Baseline Turbine.

From Input Page	
Machine Rating (kWs)	1500
Rotor Diameter (meters)	70
Hub Height (meters)	65

Land Based Turbine

Cost in $	**2002**	
Component	**Component Costs $1000**	**Component Mass kgs**
Rotor	**237**	**28,291**
Blades	152	13,845
Hub	43	10,083
Pitch mchnsm & bearings	38	3,588
Spinner, Nose Cone	4	775
Drive train,nacelle	**617**	**43,556**
Low speed shaft	21	3,025
Bearings	12	679
Gearbox	153	10,241
Mech brake, HS cpling etc	3	
Generator	98	5,501
Variable spd electronics	119	
Yaw drive & bearing	20	1,875
Main frame	93	19,763
Electrical connections	60	
Hydraulic, Cooling system	18	120
Nacelle cover	21	2,351
Control, Safety System, Condition Monitoring	**35**	
Tower	**147**	**97,958**
	0	
TURBINE CAPITAL COST (TCC)	**1,036**	**169,804**
Foundations	46	
Transportation	50	
Roads, Civil Work	79	
Assembly & Installation	38	
Electrical Interface/Connections	122	
Engineering & Permits	32	
	0	
	0	
	0	
BALANCE OF STATION COST (BOS)	**367**	**0**
	0	
Initial capital cost (ICC)	**1,403**	**169,804**
Installed Cost per kW (cost in $)	**935**	**113,203**
Turbine Capital per kW sans BOS & Warranty (cost in $)	**691**	**113,203**
Levelized Replacement Cost $ per year	16	
O&M $ per turbine/yr	30	
Land Lease Cost	5	
CAPACITY FACTOR	**32.82%**	
Net ANNUAL ENERGY PRODUCTION Energy MWh (AEP)	**4312**	
Fixed Charge Rate	11.85%	
COE $/kWh	**0.0476**	

Table 3. Cost Estimate from Scaling Model: Offshore (Shallow-Water) 3-MW Baseline Turbine.

From Input Page	
Machine Rating (kWs)	3000
Rotor Diameter (meters)	90
Hub Height (meters)	80

Offshore Turbine		
Cost in $	**2005**	
Component	**Component Costs $1000**	**Component Mass kgs**
Rotor	**477**	**50,957**
Blades	319	28,809
Hub	69	14,842
Pitch mchnsm & bearings	83	6,162
Spinner, Nose Cone	6	1,145
Drive train,nacelle	**1,425**	**88,552**
Low speed shaft	59	6,251
Bearings	32	1,650
Gearbox	408	20,973
Mech brake, HS cpling etc	6	
Generator	211	10,426
Variable spd electronics	266	
Yaw drive & bearing	46	4,312
Main frame	168	40,426
Electrical connections	150	
Hydraulic, Cooling system	41	240
Nacelle cover	38	4,273
Control, Safety System, Condition Monitoring	**60**	
Tower	**415**	**200,762**
Marinization (13.50% of Turbine and Tower System)	**321**	
TURBINE CAPITAL COST (TCC)	**2,698**	**340,271**
Monopile foundation/Support Structure	1,114	
Transportation	281	
Port and staging equipment	74	
Turbine Installation	371	
Electrical Interface/Connect	926	
Permits, Engineering, Site Assessment	119	
Personnel Access Equipment	64	
Scour Protection	204	
Surety Bond (Decomissioning - 3.0% of ICC)	176	
BALANCE OF STATION COST (BOS)	**3,331**	**0**
Offshore Warranty Premium (15.00% of Turbine and Tower System)	**357**	
Initial capital cost (ICC)	**6,386**	**340,271**
Installed Cost per kW (cost in $)	**2,129**	**113,424**
Turbine Capital per kW sans BOS & Warranty (cost in $)	**899**	**113,424**
Levelized Replacement Cost $ per year	55	
O&M $ per turbine/yr	215	
Bottom Lease Cost	12	
CAPACITY FACTOR	**38.13%**	
Net ANNUAL ENERGY PRODUCTION Energy MWh (AEP)	**10020**	
Fixed Charge Rate	11.85%	
COE $/kWh	**0.0950**	

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