Historical and Current Trends in Wind Energy Operations Costs and Project Availability

July 2012—July 2013

Ivan Gil-Vazquez, Rick Mitchell,
and Cathy Syme
GL Garrad Hassan
San Diego, California

NREL Technical Monitor: Eric Lantz

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August 2018

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National Renewable Energy Laboratory
15013 Denver West Parkway
Golden, CO 80401
303-275-3000 • www.nrel.gov

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HISTORICAL AND CURRENT TRENDS IN WIND ENERGY OPERATIONS COSTS AND PROJECT AVAILABILITY

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Author I. Gil-Vazquez, R. Mitchell, C. Syme

Checked by J. de Montgros, A. Graves

Approved by C. Johnson

Garrad Hassan America, Inc.

9665 Chesapeake Drive, Suite 435, San Diego, California USA
Phone: (858) 836-3370 | Fax: (858) 836-4069
www.gl-garradhassan.com

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B	12 Oct 2012	Updated charts
C	29 Oct 2012	Updated report with narrative on charts and wind turbine availability section
D	17 Jan 2013	Updated following comments and discussion with Client
E	21 Feb 2013	Updated following comments and discussion with Client
F	15 Mar 2013	Final updates to Executive Summary issued in Microsoft Word document to the National Renewable Energy Laboratory per terms of proposal

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Acknowledgements

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Preface

The work detailed herein was completed in 2013 and references both current and recent trends and data as of that date. Given the time elapsed between the completion of the work and this publication, readers should be aware that these references apply primarily to the period of time during and prior to 2013 and may no longer be considered either current or recent.

The work has been published at this delayed date as a reference volume for current and future research activities in wind power operations and maintenance.

Parallel work was undertaken by DNV KEMA Renewables, Inc. in the same time frame. Subsequently, DNV KEMA and GL GH merged to form the DNV GL Group. Certain analysis methodologies and assumptions may have changed since the original research was conducted. Recent thought leadership on related topics from DNV GL may be found at: https://www.dnvgl.com/energy/publications.

Executive Summary

The National Renewable Energy Laboratory has requested [1] that Garrad Hassan America, Inc. (GL GH) provide a report containing charts, figures, and qualitative opinions on trends in wind energy operations costs and reliability with the purpose of enabling the National Renewable Energy Laboratory to develop a historical turbine operating cost and reliability baseline. The charts and figures are developed from a database maintained by GL GH containing the operating costs for 66 wind projects in North America with over 5,000 wind turbines and approximately 7,000 megawatts of capacity.

Based on the GL GH sample, it appears that the wind projects in North America are capable of achieving 96% system availability on average over many years of operations; however, many markets in the United States in particular now experience grid congestion curtailment, and projects in these areas perform in the 70% to 95% availability range depending on the severity of the curtailment. In addition to curtailment, there are several other factors including regional environmental conditions, wind turbine model type, and age of the project that will contribute to the system availability of an individual wind project in a given year.

When a project emerges out of the warranty phase, unscheduled maintenance costs become the most variable and expensive operating cost as a result of the uncertainty in major component lifetimes, which make accurate estimations of maintenance costs difficult. The potential cost of gearbox repairs and replacement and associated crane costs are some of the key concerns of wind project owners and the results presented in this report are influenced heavily by a few turbine models that have serial defects in the gearbox design. Gearboxes with serial defects tend to fail between the fourth and eighth year of operation. For these models, failure rates can be as high as 20% to 30% during these years. Most projects without serial gearbox defects will have small increases in gearbox failures over time, rising to approximately 2% to 4% by the fifth to sixth year of operation with the appropriate gearbox failure rate for any given project being dictated by turbine type and component supplier.

The ability to operate the wind turbines efficiently and avoid downtime during peak production periods has become a key element in proactive preventative maintenance. In recent years there has been an increase in the variety of options for turbine operation and maintenance (O&M) available to wind project owners as the number of wind farms has increased and created a competitive market particularly in locations where there are significant populations of wind projects in close proximity. Postwarranty O&M strategies can be various combinations of original equipment manufacturer, owner/operator, or third-party O&M providers.

To determine what happens to turbine O&M costs over time, the GL GH analysis focused on the capacity weighted mean of total turbine scheduled and unscheduled maintenance and separated the sample projects into two groups dependent on commercial operation date (COD). Group 1 has projects that have a COD up to December 31, 2008, and Group 2 has projects with a COD after 2008 (from January 1, 2009).

The cost per kilowatt capacity weighted mean for Group 2 projects is 11% and 38% higher than the earlier wind projects in years one and two, respectively. Despite increasing competition in fixed-price contracts for scheduled maintenance and full-wrap agreements, the overall fixed fees are also higher than Group 1 projects partly because Group 2 includes projects with the newer full wrap agreements and higher fixed fees that owners pay a premium to have greater cost certainty. The Group 2 projects also reflected higher labor costs and additional costs resulting from building in more remote or challenging site conditions.

In contrast, when the data were viewed in the context of how much revenue is earned relative to the operating cost per kilowatt of the turbine, it became clear that the Group 2 projects are out-performing their older predecessors. Larger turbines, higher capacity factors, and in some cases higher energy rates combined with market competition to lower scheduled turbine maintenance costs are the main reasons why the capacity weighted mean of more recent wind projects appears to be achieving a contribution margin (energy revenue less total turbine and balance-of-plant costs) of at least 50% more than projects with a COD up to December 31, 2008.

1 Introduction

The National Renewable Energy Laboratory (hereafter referred to as the Client or NREL) has requested [1] that Garrad Hassan America, Inc. (GL GH) provide a report containing charts, figures, and qualitative opinions on trends in wind energy operations costs and reliability.

The purpose of this report is to enable NREL to develop a historical turbine operating cost and reliability baseline that is grounded in a representative sample of empirical data from North America and at the same time, enhance NREL's ability to understand if and how technological advancements have impacted project operating costs and reliability.

The wind farm operation and maintenance (O&M) market has fundamentally changed over the last 10–15 years. In the early years, the original equipment manufacturers (OEMs) dominated the market and turbine O&M was typically was offered as part of a sales and warranty package and therefore often not seen as a separate business. Today, the market is much more sophisticated and competitive—especially with third-party providers in the United States along with larger portfolio owners opting to manage their own (or self-perform) wind farm operations. During this time, there has also been an increasing focus on health and safety, which brings both time-based benefits (i.e., climb assist and lifts) and additional overhead in the form of better documentation of control processes. In addition, there is a growing tendency to monitor O&M centrally through improved supervisory control and data acquisition systems.

Several views of wind project operating costs are derived from the GL GH benchmark database and are presented in the following sections by describing the database, cost categorization, and analysis methodology as well as providing graphical views in terms of total operating cost, transition from warranty to postwarranty, and turbine scheduled versus unscheduled capacity weighted costs.

1.1 Database Size and Distribution

The GL GH Wind Project Operating Cost database contains the operating costs for 66 wind projects in North America with over 5,000 wind turbines and approximately 7,000 megawatts (MW) of capacity. The age of these 66 wind projects range between 1 and 10 years, which represents a sample of 240 years of operational data. Approximately 20% of the wind projects in this database are comprised of smaller, stall-regulated machines rated between 100 kilowatts (kW) to 900 kW. The majority of the wind projects are operating with pitch-regulated machines at a rated turbine capacity of 1 MW or greater. Figure 1-1 shows the distribution of pitch- versus stall-regulated machines within the sample. The sample data include a variety of hub heights and capacity factors, and as technology has developed the newer turbine models include additional features, such as state-of-the-art gearboxes, improved automated lubrication systems, additional bearings to de-couple loads, extra yaw gears, more sophisticated control systems, transformers in the nacelle, condition monitoring, and improved grid code compliance and control.

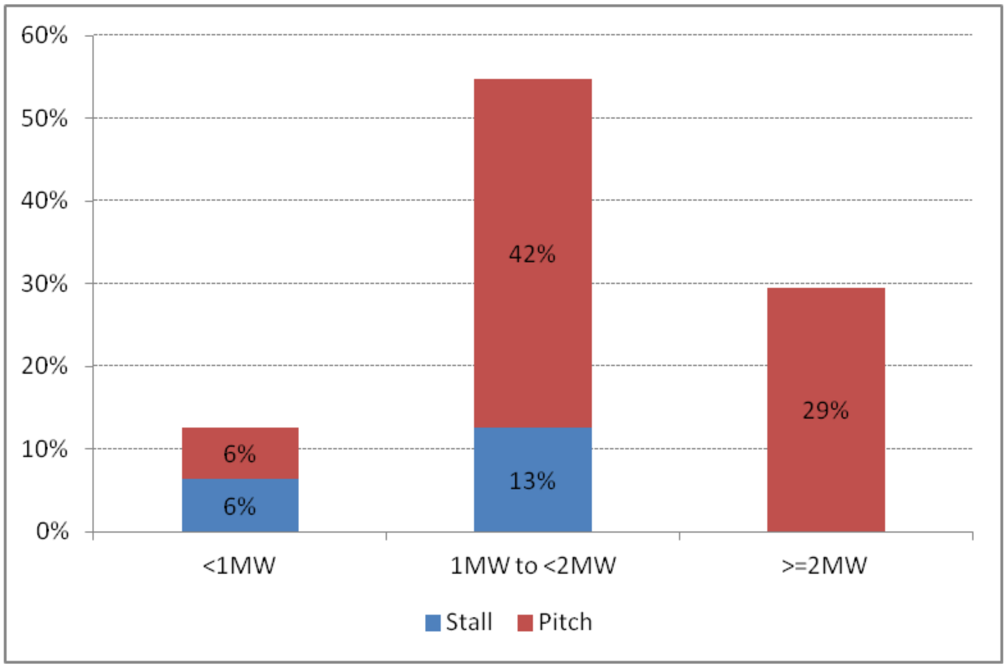


Figure 1-1. Distribution of stall- versus pitch-regulated wind turbines in the sample

1.2 Operating Cost Analysis

The operating costs for each wind project in the GL GH database were classified into the categories defined in Table 2-1**.** The cost parameters described in the benchmark charts were calculated on a cost-per-kW of installed capacity basis, and the values were taken from the wind project's actual operating cost data normalized to 2012 dollars by applying a Consumer Price Index factor [2] to the data for each operating year.

The results of the analysis are displayed in Figure 1-2, which shows a box containing the 25th percentile, median, and 75th percentile cost for the cost category in the sample. The whisker bars on the box plot correspond to the 10th and 90th percentiles of the sample for the cost category. NREL specifically requested that GL GH focus on the capacity-weighted mean, which is calculated as:

$$\frac{\sum_i^n (Project\ cost_i) * (Project\ capacity_i)}{\sum_i^n project\ capacity_i}$$

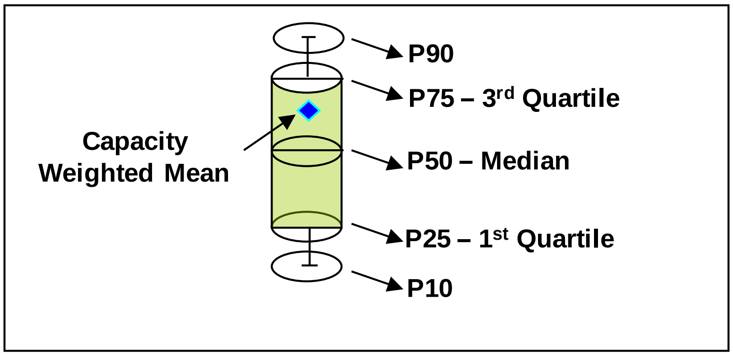


Figure 1-2. Box plot legend

1.3 Definition of Operating Costs

When discussing wind farm operating costs, it is important to be clear as to which costs are included in the calculation, as there are a variety of naming conventions used in the industry to describe these costs.

Typically, the term wind farm operating expenditures (OpEx) is used to describe ALL wind project operating costs, or all the costs that contribute to running the wind farm, from the turbine and balance-of-plant service and maintenance to the administrative costs (e.g., accounting, legal fees, and contract management at the head office). Table 2-1 provides a detailed list of these costs.

Some analysis refers to wind project O&M as the cost of turbine scheduled and unscheduled maintenance, whereas others include turbine and balance-of-plant (BOP) components as O&M. For the purposes of this report, it will be clearly stated whether or not O&M costs are for turbine only or turbine and BOP.

1.4 Measures of Wind Project Costs

Wind project costs may be calculated in a variety of ways, the most common being:

- Cost per kW or MW
- Cost per kilowatt-hour (kWh) or megawatt-hour (MWh)
- Cost per turbine

This report also introduces another methodology “cost per contribution margin;” whereby, the cost per kW is viewed in terms of the contribution towards cash. With this methodology, a project’s energy revenues are reduced by the turbine and balance-of-plant O&M costs, resulting in the remaining cash that would contribute toward repayment of the project debt or potential dividend distribution.

The methodology and results of the study are reported herein.

2 Wind Project Operating Costs

2.1 Operating Expense Categories

During the course of this work, we have seen a wide variety of naming conventions for wind project operating cost categories that can make it difficult to view different costs on an apples-to-apples basis. Therefore, to provide a clear and consistent approach to classifying wind project operating costs, GL GH has mapped individual project line items to specific cost categories (shown in Table 2-1). An “f” or “v” is included after each cost category title to denote whether it is typically a fixed or variable cost. This list is provided as guidance and is not exhaustive.

Table 2-1. Benchmarking Cost Categories

Operating Cost Category		Description
Turbine Scheduled O&M	f	Fixed fees exclusive of specific warranty fees, labor cost if self-performing work, contracted scheduled maintenance activities, tools and equipment; personnel costs such as travel and meals
Turbine Unscheduled Repairs	v	Unexpected maintenance such as parts costs, cranes, defect-related labor costs, spare parts, and consumables
Balance-of-Plant (BOP) Maintenance	v	O&M conducted on-site to components including the collection system and substation; roads and fences; spare parts and consumables; vehicles; waste management; security; O&M building rent; and office supplies
Utilities	v	Energy usage, facility utilities, telecommunication expenses, information technology costs
Project Administration Fees	f	Project administration and management fees, such as inventory fees
Generation Charges	v	Charges related to system operator/transmission, production shortfall penalties, and scheduling and forecasting fees
Land Leases/Royalties	v	Lease payments or royalties payable to third-party land owners
Insurance	f	Insurance premiums and/or deductibles related to the wind project site
Property Tax	f	Taxes due with respect to the wind project site
Outside Professional & Advisory	v	Environmental expenses or consultant fees related to auditing, legal, or tax services; meteorological data analysis, or regulatory compliance
Other General & Administration		Co-tenancy fee, bank/guarantee fees, community involvement, license, permits and fees, sales and marketing costs, and miscellaneous expenses

2.1.1 Scheduled O&M

Turbine scheduled maintenance may be performed by the OEM, a third party, or the owner/operator. Typically, the OEM and third party would charge a fixed fee for these costs; however, there have been occasions in which the fee may be production-based. Owner/operators may charge a fixed fee through an affiliate company or charge for direct labor costs and associated materials. These activities have historically been time-based turbine visits set at 6-month intervals that include mechanical activities such as fluid level checks, greasing, bolt torque checks, filter changes, and inspection of the blades and hydraulic systems, as well as electrical activities, such as inspection of cable connections, fuse checks, voltage level checks, battery inspections, trip tests, and electrical cable inspections. The scope of work associated with each maintenance visit will vary. For example, minor operations and checks will be performed at every visit, whereas major operations such as generator alignment, complete bolt torqueing, lubricating, and cleaning will be performed on an annual basis. Other major items, like a complete oil change, may be performed once every 5 years.

2.1.2 Unscheduled Repairs

Unscheduled turbine work involves maintenance and repairs that are not covered under the scope of work for scheduled activities. Some examples include blade washing, repairing or replacing parts from unexpected wear and tear, labor outside normal business hours, owner-generated work, and gearbox oil changes which may or may not be included in the scope of the service agreement. Once the initial turbine warranty has expired, unscheduled maintenance may also include costly repair and replacement of major components, such as gearboxes, generators, and blades, which contains the cost of additional labor, cranes, and equipment required to perform the work. Unscheduled repairs are the most variable and expensive operations cost once a project emerges out of warranty due to the uncertainty in component lifetimes, thereby making estimations of maintenance costs challenging.

2.1.3 Balance-of-Plant Maintenance

BOP maintenance is the cost to maintain all wind plant infrastructure and facilities. This type of maintenance is mainly focused on turbine foundations, crane pads, the substation and collection system, padmount transformers, electrical cables, site access roads, the supervisory control and data acquisition system and O&M building. The project owner is responsible for the coordination and delivery of the scope of work contemplated in the applicable BOP agreements, but with a few exceptions. Most projects utilize third-party electrical subcontractors to perform major maintenance or repair activities.

Routine BOP maintenance generally follows the manufacturers' guidelines and is segmented into weekly, biweekly, and monthly inspections. Depending on the corporate strategy, the BOP costs may be fixed or variable, or a combination of both, because the project may have a fixed BOP agreement for certain activities and self-perform the out-of-scope BOP service activities, such as road maintenance, substation maintenance, or high-voltage work.

2.1.4 Utilities

The project utility cost is variable because the cost depends on turbine and facilities electrical usage and may include telecommunications and information technology connection expenses. Occasionally the off-taker and/or utility will net the turbine usage/back-feed costs against the project revenues.

2.1.5 Project Administration and Management Fees

Depending on the corporate strategy, the project management and administration costs may be fixed or variable or a combination of both. The asset manager is generally responsible for the asset performance, contract administration, safety requirements, environmental issues, project deliverables, and internal and external reporting. Contract and insurance negotiation may be required under the management agreement, if it is not performed at the parent corporate level and these costs are typically passed through as operating expenses; however, there may be some management overhead that is absorbed within the equity return.

2.1.6 Generation Charges

Generation costs may have a fixed and variable cost component. Production shortfall penalties may also be applicable under the terms of the power purchase agreement (PPA) if it requires a guaranteed production level on an annual or rolling average basis. Occasionally, wheeling and transmission charges may be required under a long-term transmission agreement. The most common contractual arrangement in a wind energy PPA is to simply deliver output energy to the point of interconnection. Under this scenario, the off-taker would bear all costs associated with the transmission needed to move power to the desired final delivery point. The point of delivery for the wind energy is specified in the PPA, and if it is different from the wind project interconnection bus then transmission costs can come into play.

The most common transmission costs would be congestion costs, defined as the hourly difference in nodal price between the wind injection bus and the delivery point specified in the PPA, assuming they are both in the same energy market (or Regional Transmission Organization). Wheeling costs may come into play if the delivery point specified in the PPA is in a different Regional Transmission Organization from the wind interconnection point. A wind project operating as a merchant plant without a PPA receives payment for energy based on the nodal price at the interconnection bus and is not subject to transmission congestion costs or wheeling costs.

Forecasting and scheduling costs are another expense the project may incur, as it is becoming common for projects to be required to provide a production schedule and forecast to the off-taker. These services are contracted with a third party and negotiated generally at a fixed fee over a period of time, and as a result the cost varies from project to project. Imbalance fees may be charged to the project by the independent system operator, and these costs vary from month to month depending on the accuracy of the project’s actual output as compared to the forecast.

2.1.7 Land-Related Costs

The land leases and royalty costs are determined by the wind energy lease agreements set in place with the landowners. For the most part, these leases have agreed terms for a combination of the following cost items: minimum rents (fixed), percentage royalty (variable based on energy production or revenue), and any additional rents (fixed or variable). Land easements may have a fixed annual rent whereas other project land leases may be tied to a percentage of production revenue.

2.1.8 Insurance

Insurance costs are determined by the current market conditions and the wind farm's loss and claim history. The project prepays an annual or semiannual insurance premium amortized on a straight-line basis over a 6 or 12 month period. Thus, the insurance expense will be reflected in the profit and loss account as a fixed monthly expense.

2.1.9 Property Tax

Property tax costs are determined by the local tax authorities, such as the county or community tax assessor. The methodology for assessing property taxes varies across North America, and there may be green tax incentives offered to reduce the property assessed value. The property tax cost is typically amortized or accrued on a monthly basis and is reflected, for the most part, on the profit and loss account as a fixed monthly cost.

2.1.10 Professional Service

The third-party professional services for legal, environmental, tax, audit, regulatory compliance, independent engineering, and meteorological services are variable costs as they depend on the requirements of each project.

2.1.11 Other General Administration Costs

General administration costs are a variable project expense that is related to the level of detail that is used to account for project expenses. This category may include costs such as community involvement; licensing, permitting, and fees; sales and marketing costs; and miscellaneous expenses.

2.2 O&M Strategies and Their Effect on Operating Costs

When considering the data set for turbine scheduled and unscheduled maintenance, choosing the appropriate O&M strategy can have a notable effect on the cost of operations. In recent years, there has been an increase in the variety of options for turbine scheduled and unscheduled maintenance available to wind project owners as the number of wind farms have increased and created a competitive market particularly in locations where there are significant populations of wind projects in close proximity. As a result, this type of maintenance may be performed by the OEM, a third party, an owner/operator (self-performing) or a combination of all three.

2.2.1 Turbine Scheduled O&M

The initial agreements during the warranty period are typically for a fixed service fee and the scope of work generally follows the turbine manufacturer's operating manual.

Postwarranty O&M strategies can be various combinations of OEM, owner/operator, or third-party O&M providers. Some experienced owners of multiple wind projects prefer to perform O&M activities on their own, taking advantage of lower costs and economies of scale with regard to labor, owner-purchased equipment, in-house repair shops, and supplier discounts. Owners new to the industry or with a remote or smaller capacity wind project tend to prefer an OEM or third-party O&M provider, thus taking advantage of service providers that are already present and experienced in a particular region. The cost effectiveness of self-operations does, however, need to be weighed against the performance warranty and increased exposure to cost variability that might have otherwise been mitigated by a third-party fixed fee with performance guarantees.

It should be noted that as a wind project transitions out of warranty during an operational year, the turbine scheduled O&M costs will include a combination of OEM and postwarranty O&M provider fees; and in most cases there will be additional lump sum costs for spare parts inventory and possibly end-of-warranty inspections.

2.2.2 Turbine Unscheduled Repairs

During the warranty period the unscheduled turbine repairs and replacement costs for major components are covered by the OEM and include the cost of labor, cranes, and equipment. The cost of the equipment warranty (often 2 years) is generally included in the price of the turbines under the turbine supply agreement, but there are instances of OEMs charging a fixed fee during the operating warranty period that represents the cost of the warranty. Therefore, to avoid skewing the data, warranty fees are excluded from the reported data in this study. Thus, aside from maintenance activities that may not be covered by the OEM scope of work, there will be no charge to the wind project operating costs for unscheduled maintenance during the warranty period.

Parts-only warranties allow owners to self-operate the project from the commercial operations date but retain a warranty only on the equipment, provided that they follow the manufacturer's operating and maintenance procedures. Thus, the cost of the parts is covered by the OEM warranty; however, the labor and associated equipment costs are payable by the owner and are variable, depending on the nature of the work.

When a project emerges out of the warranty phase, unscheduled maintenance costs become the most variable operating costs because of the uncertainty in major component lifetimes that make accurate estimations of maintenance costs difficult. In recent years, there has been an increase in extended service and maintenance or full-wrap agreements offered by the OEMs that cover scheduled and unscheduled turbine maintenance at a fixed rate providing a level annual cost over the term of the service contract with the aim to reduce or eliminate cost variability. In the European Union OEMs are increasingly moving to a fee that combines all scheduled and unscheduled work on a per-kWh basis under a long-term (up to 15 year) agreement and this fee basis is starting to be offered in the United States. In spite of this, the owners do bear some risk of additional costs with repairs or replacements as a result of extraordinary wear and tear or out-of-scope work, although under a full-service agreement such costs should be relatively minor. For these types of agreements, the location and site conditions—for example high turbulence or a high capacity factor—can create more risk of additional extraordinary maintenance costs.

Owners should carefully consider and agree on the definition of such terms during the negotiation of a full-wrap agreement.

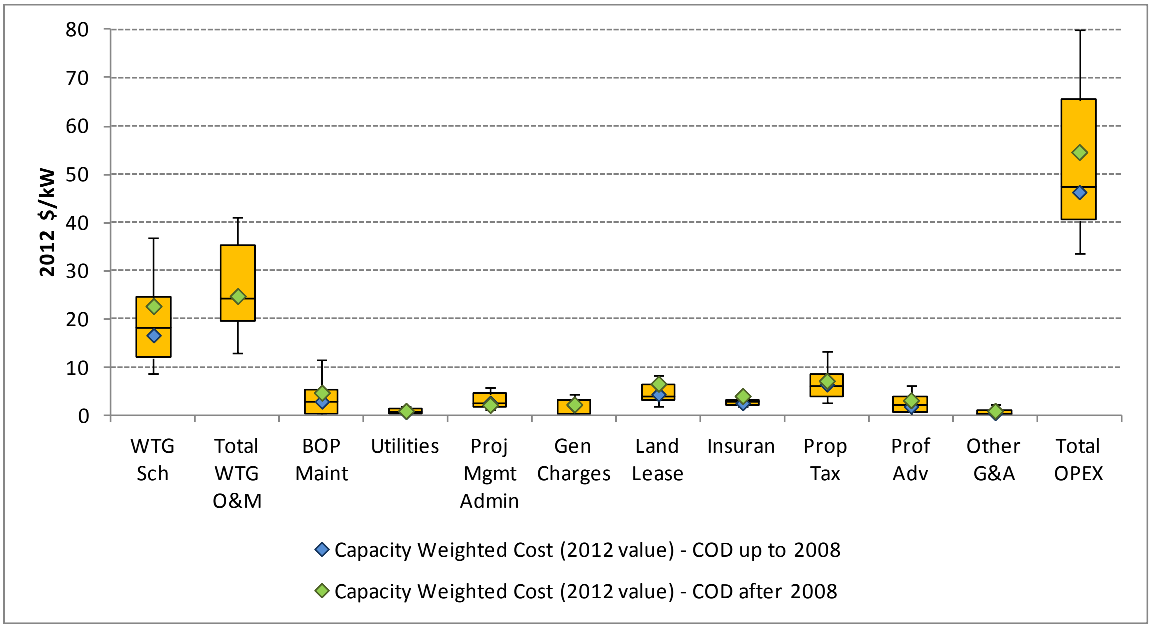
2.2.3 Total Operating Costs (Actual) for 2011 in North America

Figure 2-1 presents all operating cost categories for the sample data set of North American projects operating in 2011 both under warranty or postwarranty. During the warranty period, which varies between 2 to 5 years in this sample, most projects pay a fixed fee for wind turbine generator (WTG) scheduled service and maintenance, which generally represents the cost of labor and incidental parts and consumables.

Once the wind project is out of warranty, the cost of unscheduled maintenance may be payable by the project owner if not covered by a fixed fee; however, it should be noted that unscheduled maintenance costs vary considerably depending on the nature of mechanical issues, the turbine model and age, and site conditions. It can therefore be misleading to benchmark turbine costs for unscheduled maintenance by calendar year and not by age of project.

Typically, BOP maintenance costs would be expected to be similar for projects that are both under and postwarranty. The under warranty sample includes some smaller scale projects and a few projects in remote areas that do not benefit from economies of scale, therefore operating costs on a cost-per-kW basis are higher because of increased transportation costs, lack of vendor options, and a limited qualified labor pool.

All other costs appear to remain relatively constant regardless of being under or postwarranty, with the exception of land rent and leases that are typically directly correlated to revenue or production and property taxes subject to the methodology of the local assessment.



Note: Individual cost totals may not sum to total OpEx because of the age of the sample projects and whether or not they are under or out of warranty

Figure 2-2. Total 2011 wind project operating costs during and after the warranty period

2.2.4 Transition from Warranty to Postwarranty

Figure 2-2 represents an analysis of the total turbine operating costs of a wind project during the three stages of the project life that occurred during 2011:

1. OEM warranty period (32% of the 2011 sample)
2. The transition from OEM warranty (18% of the 2011 sample)
3. Postwarranty operations (50% of the 2011 sample).

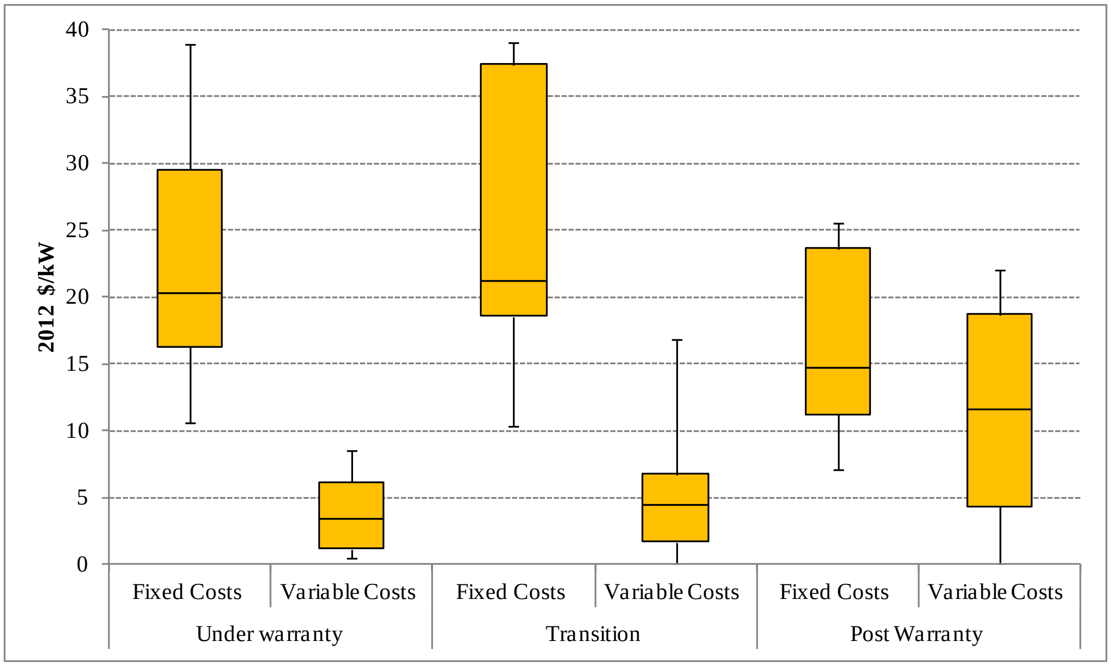


Figure 2-3. Total 2011 turbine O&M costs per kW

Table 2-2 summarizes key cost drivers in terms of the project life cycle grouped into fixed and variable costs.

Table 2-2. Fixed and Variable Cost Drivers by Period of Project Life

Period of Project Life	Fixed	Variable
Under Warranty	OEM turbine service fee. The higher cost in the sample is the result of full-wrap agreements, which include unscheduled maintenance costs that have been levelized and included in the fixed fee.	Out-of-scope services or costs for wear and tear on parts
Transition	A variety of factors including: • Transition to OEM extended turbine service fee • Full wrap covering both scheduled and unscheduled maintenance • Direct cost of labor plus mobilization costs if setting up self-performing operations • One-time end-of-warranty inspection	• Purchase of spare parts inventory, 24/7 monitoring costs • Unscheduled maintenance costs for traditional turbine service agreement • Wear and tear and out-of-scope work for the full-wrap agreement • End-of-warranty inspections
Postwarranty	Fixed fee or labor costs for scheduled maintenance or a full-wrap fee	Unscheduled maintenance costs for traditional turbine service agreement; wear and tear and out-of-scope work for full wrap agreement

In Figure 2-2, the fixed costs increased considerably during the 2011 transition period. This is a result of a combination of larger projects transitioning out of traditional OEM service and warranty fees and incurring additional costs for end-of-warranty inspections and additional spare parts inventory. Because the full-wrap agreements are relatively new, the sample of postwarranty projects do not include this type of arrangement. Instead, the 2011 sample shown in Figure 2-2 represents more traditional turbine O&M service agreements, with the owners being responsible for unscheduled maintenance costs.

During the postwarranty period, scheduled WTG costs tend to decrease (a step change at the transition point, rather than a steady downward trend), whereas unscheduled WTG costs increase as the wind project owner takes on responsibility for the repair and replacement of all turbine parts. Depending on the age of the project and the issues related to the specific technology, the cost per kW of unscheduled maintenance can vary significantly during the life of the project.

2.2.5 Turbine O&M Costs by Project Age—Capacity Weighted Cost

Figure 2-3 through Figure 2-6 include projects with commercial operation dates ranging from 1993 to 2011. To determine if project age is a factor in turbine O&M costs, the sample has been divided into two groups dependent on COD. Group 1 has projects that have a COD up to December 31, 2008, and Group 2 has projects with a COD after 2008 (from January 1, 2009).

Figure 2-3 provides a comparison between the capacity-weighted cost per kW between Groups 1 (blue) and 2 (green) and it is notable that the cost per kW capacity-weighted mean for Group 2 projects is 11% and 38% higher than the earlier projects in years one and two, respectively. Despite increasing competition in fixed-price contracts for scheduled maintenance and full-wrap agreements, the overall fixed fees are also higher than Group 1 projects partly because Group 2 includes projects with the newer full-wrap agreements and higher fixed fees that owners pay a premium for to have greater cost certainty. The Group 2 projects also reflect higher labor costs and the additional costs resulting from building in more remote or challenging site conditions. When viewed on a cost-per-kWh basis, the Group 2 projects still exhibit higher costs than Group 1 projects.

When compared to Figure 2-3, Figure 2-4 shows the increase in scheduled costs for Group 1 projects as they come out of warranty in year 3. Because the Group 2 projects are only just coming out of warranty, it is not possible to provide a comparison of unscheduled maintenance costs between the two groups. The increase in costs in year 2 for Group 2 projects is a result of additional projects with a higher cost per kW. Figures 2-6 shows that the cost of scheduled maintenance for older plants has risen significantly over time such that the gap in total turbine costs (Figure 2-5) disappears by 2009.

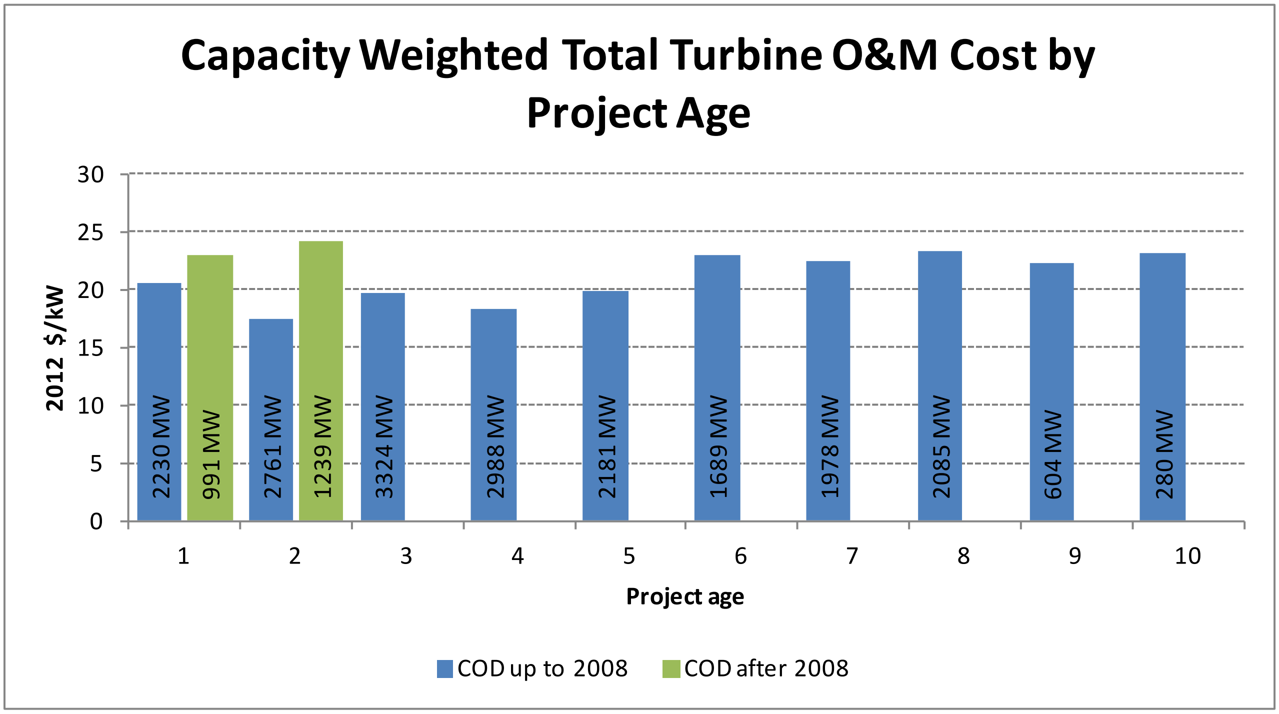


Figure 2-4. Capacity-weighted turbine total O&M cost per kW by project age

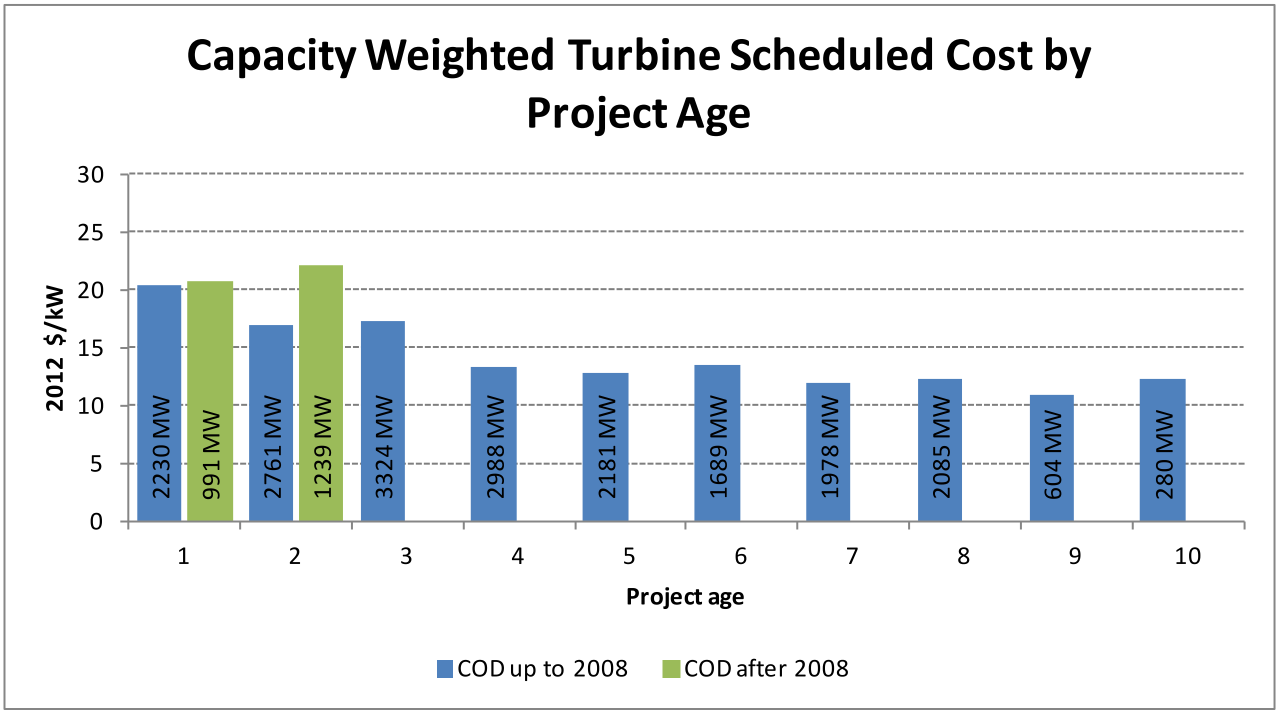


Figure 2-5. Capacity-weighted scheduled cost per kW by project age

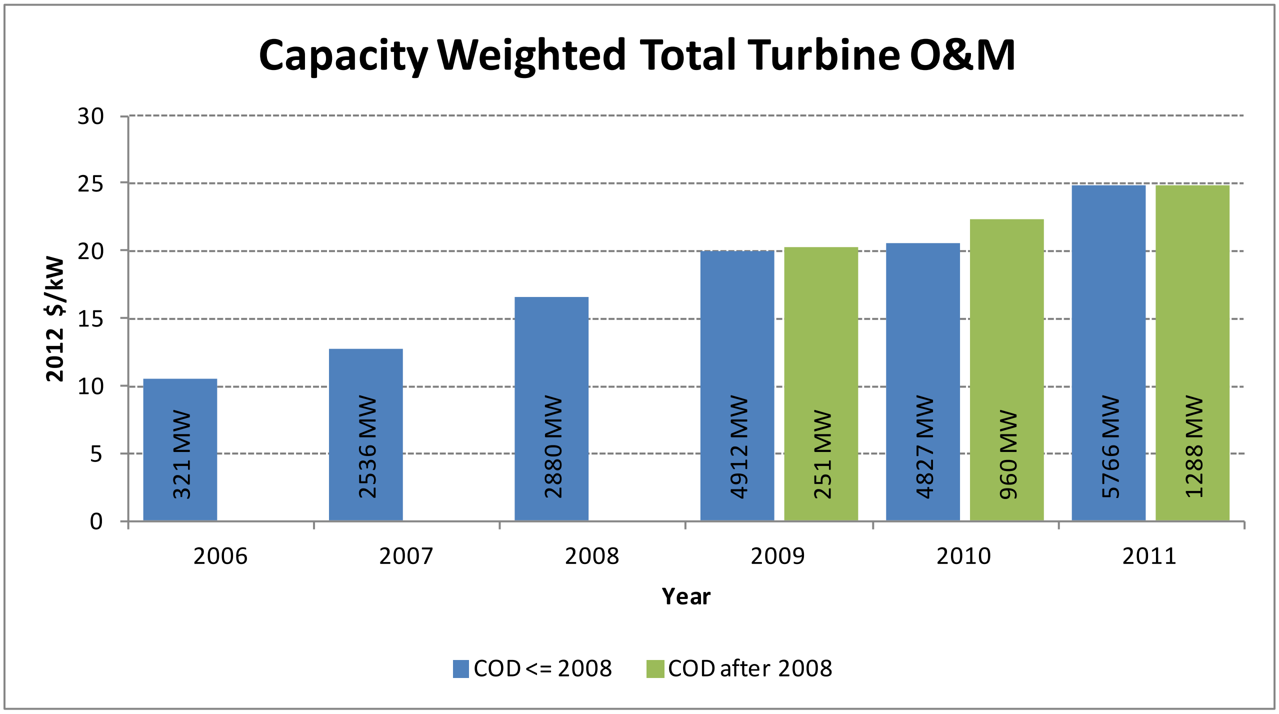


Figure 2-6. Total turbine O&M cost per kW by calendar year

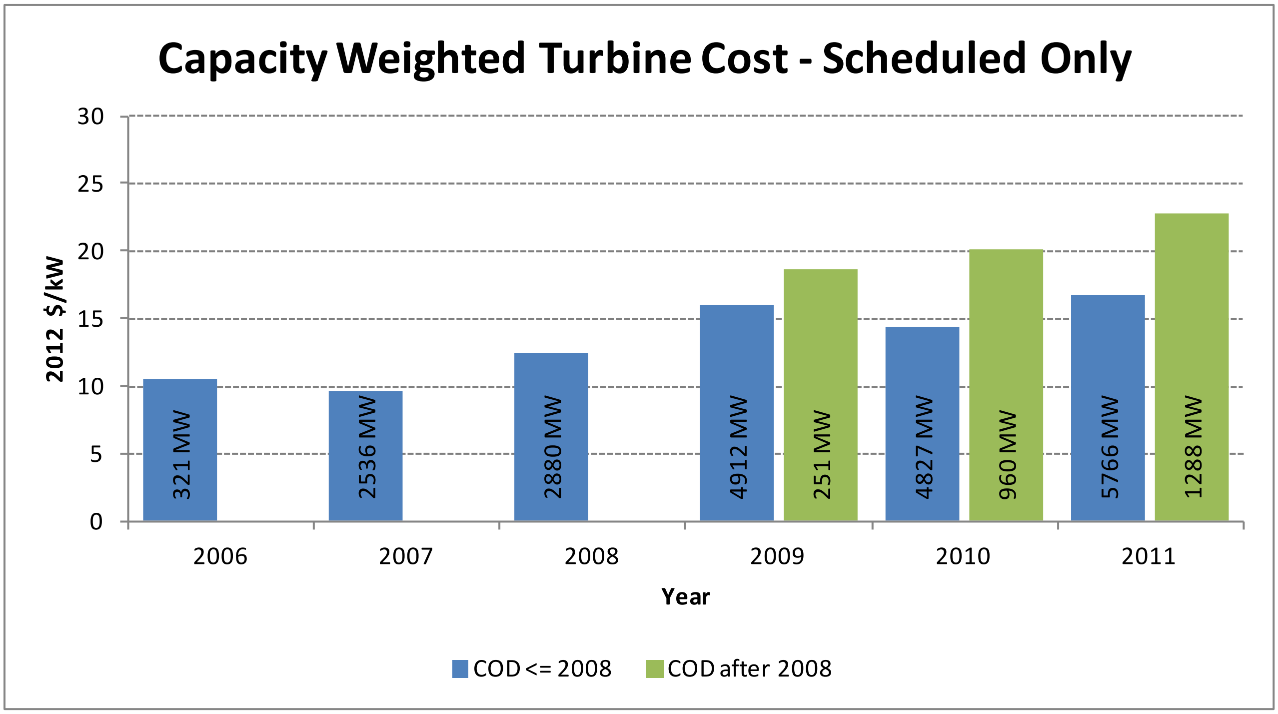


Figure 2-7. Scheduled cost per kW by calendar year

2.2.6 Capacity-Weighted Contribution Margin

When viewed in the context of how much revenue is earned relative to the operating cost per kW of the turbine, it is clear that the Group 2 or COD after 2008 projects are out-performing their older predecessors. Figure 2-7 and Figure 2-8 show the contribution margin (energy revenue less total turbine and balance-of-plant costs). Larger turbines, higher capacity factors, and in some cases, higher energy rates combined with market competition to lower scheduled turbine maintenance costs, are the main reasons why the capacity-weighted mean of more recent wind projects appears to be earning at least 50% more than the Group 2 projects.

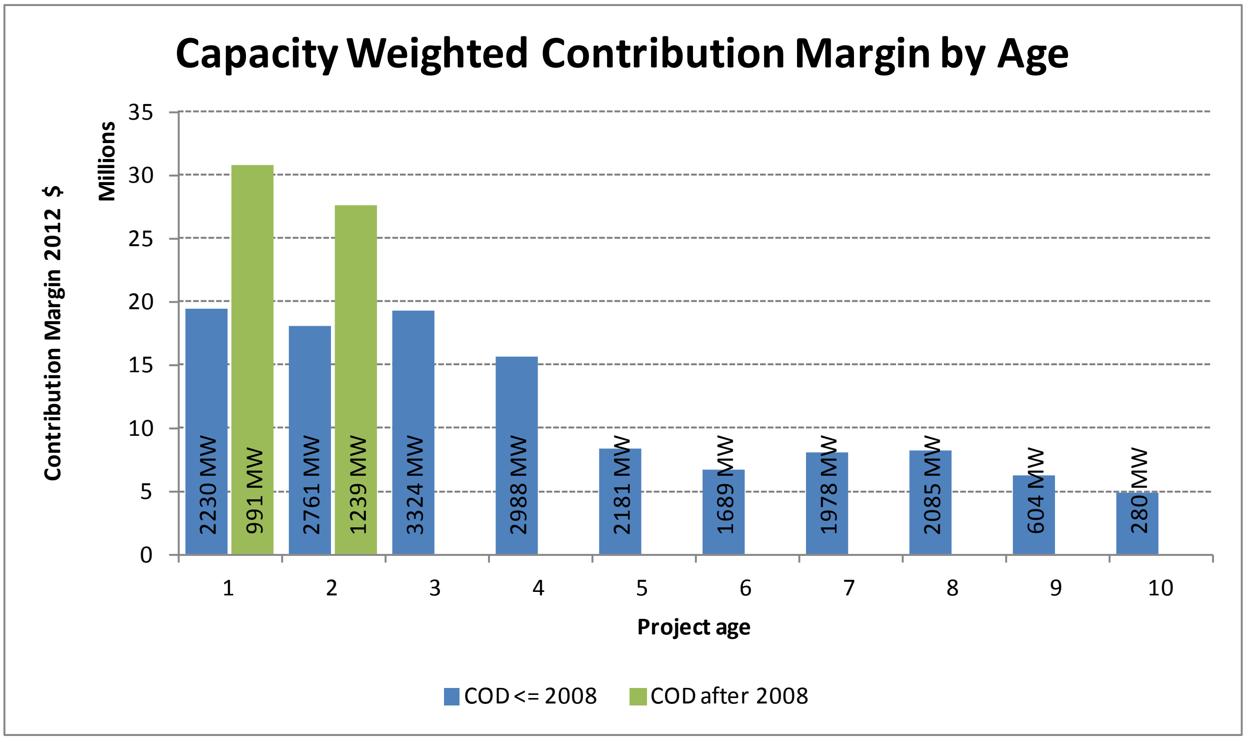


Figure 2-8. Contribution margin by age

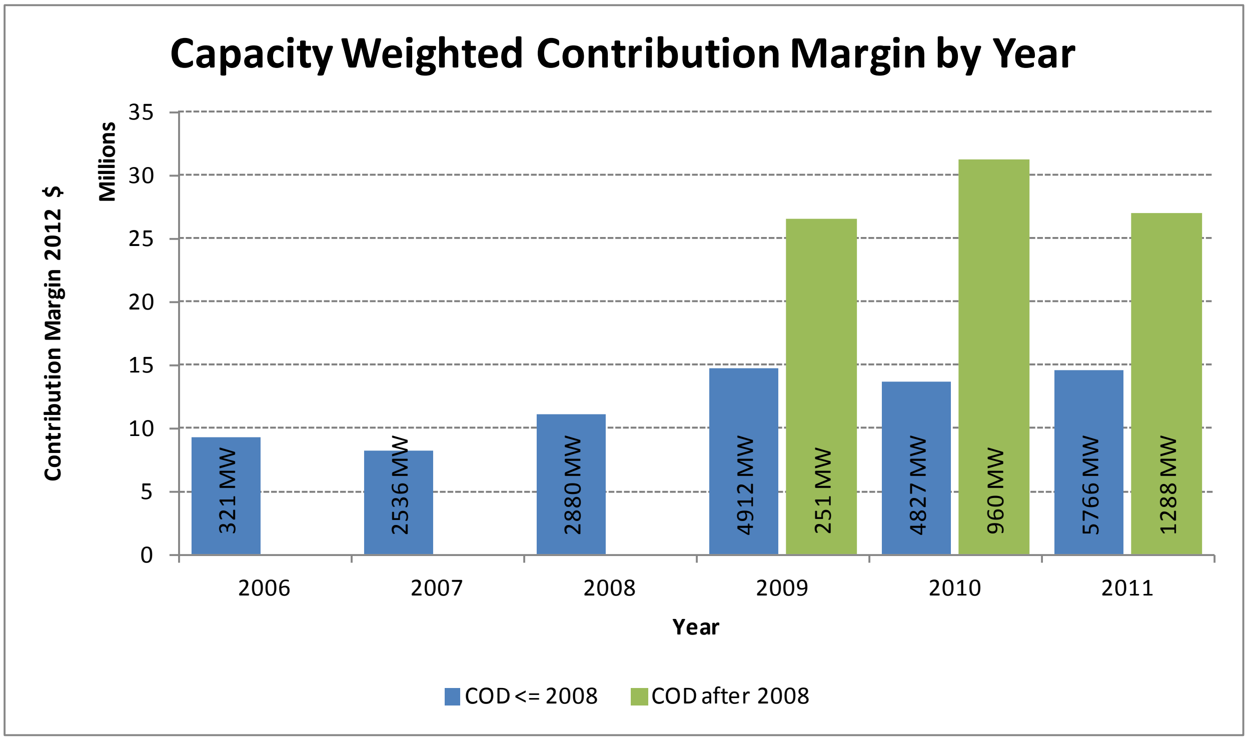


Figure 2-9. Contribution margin by calendar year

3 Wind Turbine Reliability

To assess wind turbine reliability, two metrics are generally used in the wind industry: system availability and major component failure rates. A definition of each metric, description, limitations of the data available, and overall values from the GL GH benchmark database are provided in the following sections.

3.1 System Availability

System availability provides a high-level view of downtime at a wind project. GL GH defines it as the total period of time turbines are producing energy divided by the total period of time when the wind speeds are above cut-in and below cut-out. This definition of availability is referred to as system availability because it includes all sources of downtime including curtailment and closely relates to the revenue losses associated with downtime. System availability is a contrast to contractual, technical, and/or turbine availability definitions that exclude downtime periods associated with specific turbine status or events, as well as all BOP and weather-related downtime.

GL GH maintains a benchmark database that includes the system availability on a monthly basis for approximately 200 wind projects with over 14,000 wind turbines in North America. The wind projects in this database have anywhere from 1 to over 10 years of operation. More than 85% of wind projects are operating with pitch-regulated machines with a rated turbine capacity of 1 MW or greater.

Figure 3-1 shows the system availability of the entire data set. Approximately 30% of this data set has been affected by curtailment associated with transmission grid congestion. In Figure 3-2, the projects that have experienced curtailment have been removed to provide an unbiased view.

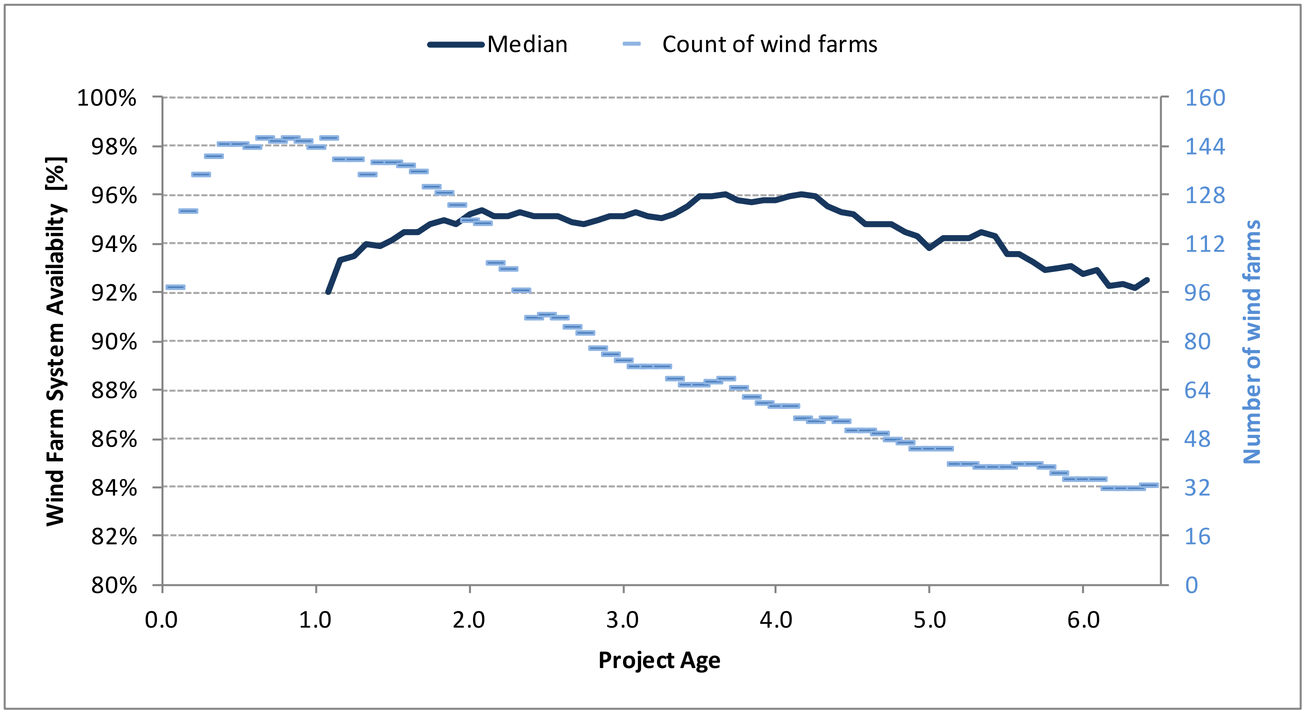


Figure 3-10. System availability for wind projects across North America

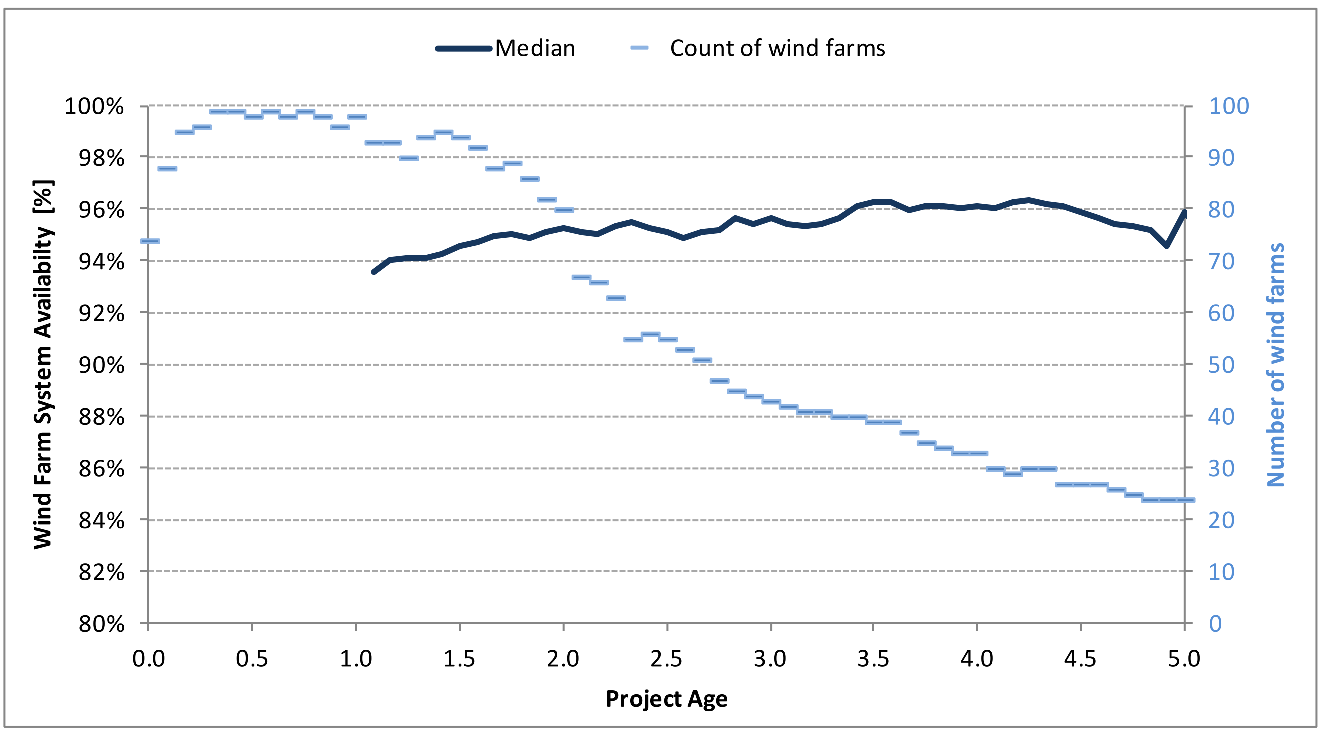


Figure 3-11. System availability for wind projects across North America excluding curtailment

The median system availability as presented in Figure 3-1 is around 95%, rising to 96% around the third year of operation in both Figure 3-1 and Figure 3-2. The wind projects that do not experience transmission curtailment maintain this level of availability, whereas the system availability for the curtailed projects drops to approximately 93% in the latter years of the data.

Figure 3-2 demonstrates that wind projects in North America are capable of running at 96% system availability on average over many years of operation. If the downtime not associated with the turbines (e.g., the collection system, roads, and substation) is removed, the resulting turbine availability is approximately 97%; however, many markets in the United States in particular now experience grid congestion curtailment, and projects in these areas perform in the 70% to 95% availability range depending on the severity of the curtailment. In addition to curtailment, there are several other factors including regional environmental conditions, wind turbine model type, and age of the project that will contribute to the system availability of an individual wind project in a given year.

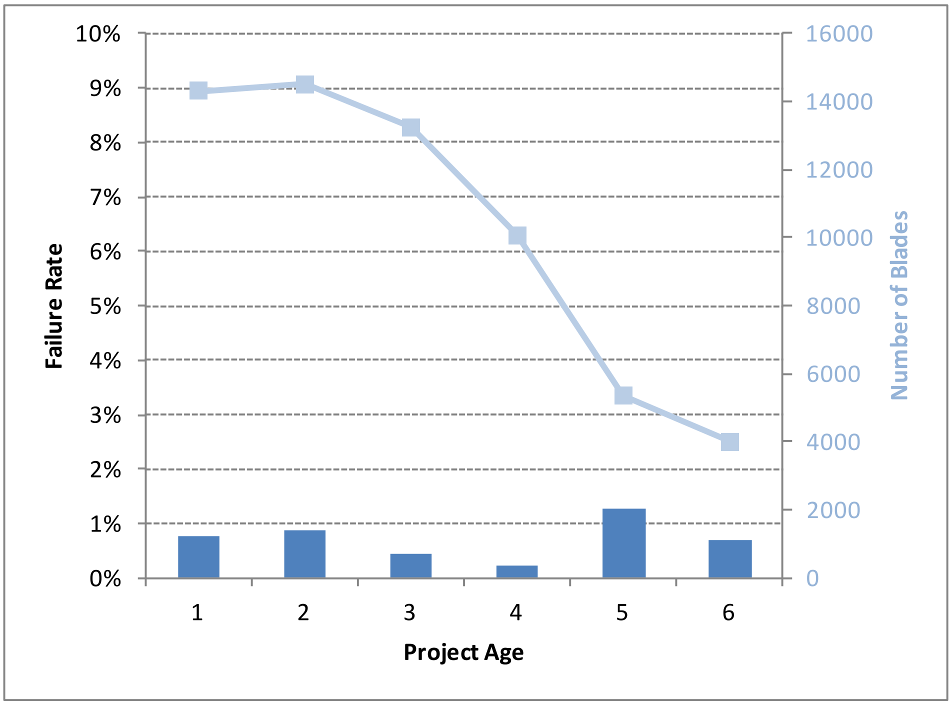
3.1.1 Major Component Failure Rates

Major component failure rates show the cost drivers of running a wind project. Major components include gearboxes, generators, and blades and are the most expensive components to replace. Tracking the failure rates of these three major components provides an indication of wind project reliability and is a key driver to the cost of operating and maintaining a given asset.

GL GH maintains a failure rate benchmark database that includes data from over 75 wind projects in the United States. The database is mainly comprised of modern projects with 1-MW turbines or greater and pitch-regulated machines in all geographic areas across the country for a number of major components, including gearboxes, generators, and blades. The failure rate benchmark database represents over 8,100 MW of wind capacity, approximately 5,000 turbines, and nearly 350 wind project years. These three major components make up almost half of the failures captured. Other turbine subcomponents showing significant failure levels are the yaw assembly, pitch system, and power module.

The term “failure” is applied broadly to represent components that have either been replaced, refurbished, or repaired. A failure may also relate to the significant breakdown of a component or minor repair of a small subcomponent at low cost. This limitation is associated with the method used to provide data for the GL GH failure rate benchmark database. Similarly, in the data provided, it is common to not receive major component failures in the early years of the project when the turbines are under warranty. Although Figure 3-3 through Figure 3-5 include many samples in the early years, as a result of the reporting methods used, the failures may be underestimated. Finally, failure rates are dependent on turbine technology and environmental conditions that will result in these statistics, which vary significantly for any specific project.

The resulting failure rates are presented by year of operation in Figure 3-3 through Figure 3-5 for blades, gearboxes, and generators, respectively. The data up through year 6 of operations is presented. Beyond year 6, the number of projects in the database is too small to be broadly representative.

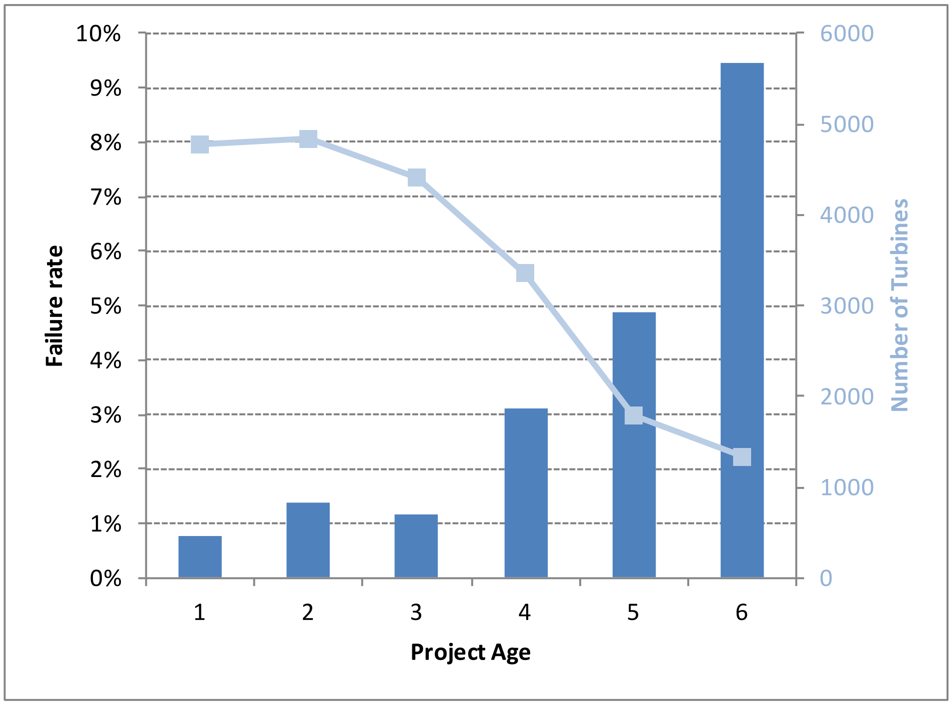


Note: The bars in this plot are scaled to the left y-axis; the line is scaled to the right y-axis

Figure 3-12. Wind turbine blade failure rates

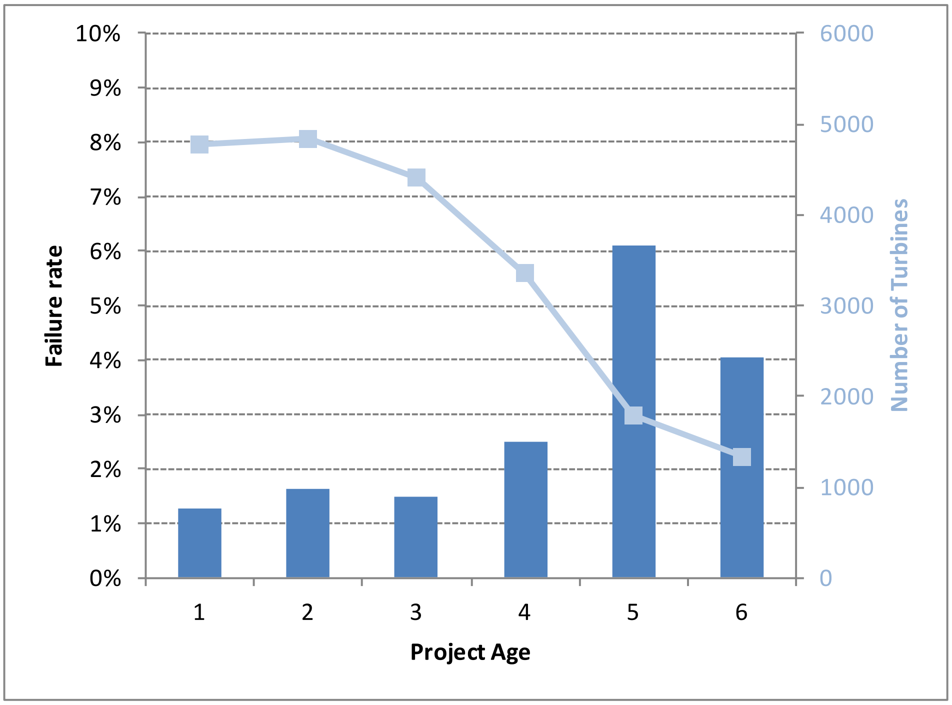
According to Figure 3-3, blades rarely fail in the first 6 years of operation. There were slightly more failures presented in the first 2 years of operation, possibly because of manufacturing defects or transportation damage, and again in the fifth year of operation. The majority of the causes reported for blade damage or failures were associated with lightning events. Blades have an average failure rate over the first 5 years of 0.7%.

The collected gearbox information presented in Figure 3-4 shows that gearboxes tend to be more reliable in the first 3 years of operation, with failures increasing rapidly in the fourth through sixth year of operation. The average failure rate over the first 6 years of operation of gearboxes is 3.5%.
The gearbox results are influenced heavily by a few turbine models that had serial defects in the design of the gearbox. The serial defect gearboxes will fail between the fourth and eighth year of operation. For these models, failure rates can be as high as 20% to 30% during these years. Most projects without serial gearbox defects will have small increases in gearbox failures over time, rising to approximately 2% to 4% by the fifth to sixth year of operation. The appropriate gearbox failure rate for any given project is dictated by turbine type and component supplier.



Note: The bars in this plot are scaled to the left y-axis; the line is scaled to the right y-axis

Figure 3-13. Wind turbine gearbox failure rates



Note: The bars in this plot are scaled to the left y-axis; the line is scaled to the right y-axis

Figure 3-14. Wind turbine generator failure rates

For generators, the collected information shows that failures are very low in the first 4 years, with a spike in the fifth year. The average generator failure rate over the first 6 years is 2.8%.

Generator failure rates are associated with a particular vintage of a few turbine models. The generators for these older turbine models may have failure rates from 7% to 12% in the third and fourth year of operation, but the remainder of projects that do not have these particular vintages of turbine models have failure rates in the fourth through sixth years between 0% to 2%. In addition, like gearboxes, generator failure rates are also driven by certain turbine models manufactured in specific years.

The GL GH database of failure rates of wind turbines indicates that the failure rates of the gearboxes and generators are around 3% on average over the first 6 years of operation, whereas blades failures average less than 1% in the same period. Gearbox and generator failures increase over the life of the wind project, rapidly for a few vintages of turbine models, and slightly for all other turbine models. Gearbox failures are the most frequent failure by the sixth year of operation because of a few turbine models with serial defects. Before extrapolating these rates to any single project cost model, we recommend considering that these variables and the bias associated with this data set are more representative of "problematic" projects.

3.1.2 Major Component Costs

Major component parts costs for turbines less than or equal to 2 MW may be significantly lower than for larger turbines. Crane costs can also fluctuate significantly from year to year as a result of supply and demand. Procurement of cranes and specialized labor in remote sites will be more challenging than sites in areas where there is plenty of competition and nearby vendors. In the days of the smaller capacity turbine it was commonplace to leave a turbine down over the weekend; however, because of the greater production capabilities of today's larger turbines, it is critical to reduce the mean time between failure and execute repairs and replacements expeditiously, which may have an impact on labor costs.

The cost of lost revenue during downtime has given rise to greater interest in condition-based monitoring, demonstrating that owners are recognizing that troubleshooting faults and predicting failures is key to effectively reducing downtime and generating optimum production. It will, however, take several more years for sufficient data to truly quantify the cost-benefit of these systems. Table 3-1 provides suggested ranges of major component costs and covers all regions of the United States. It should be noted that these costs will vary according to regional and accessibility factors.

Table 3-3. Major Component Costs Across the United States (2012 USD)

Major Component Cost 1.0 MW–2.0 MW		**Parts Cost**		**Crane Cost**	
Component	Event type	Low	High	Low	High
Gearbox	Replace	$173,300	$385,100	$80,000	$150,000
	Refurbish	$95,000	$180,000	$80,000	$150,000
	Minor repair	$30,000	$60,000		
Generator	Replace	$73,410	$164,100	$45,000	$70,000
	Refurbish	$39,400	$79,000	$45,000	$70,000
	Bearing replacement	$5,000	$10,000		
Blades	Replace	$100,000	$170,000	$80,000	$150,000
	Structural repair	$8,000	$10,000	$45,000	$58,000
	Nonstructural repair	$3,000	$5,000	$3,000	$6,000
Major Component Cost 2.1 MW–3.0 MW		**Parts Cost**		**Crane Cost**	
Component	Event type	Low	High	Low	High
Gearbox	Replace	$217,500	$628,800	$80,000	$150,000
	Refurbish	$145,000	$365,000	$80,000	$150,000
	Minor repair	$32,000	$65,000		
Generator	Replace	$75,000	$377,000	$45,000	$70,000
	Refurbish	$55,000	$95,000	$45,000	$70,000
	Bearing replacement	$6,000	$12,000		
Blades	Replace	$180,000	$320,000	$80,000	$150,000
	Structural repair	$8,000	$15,000	$45,000	$58,000
	Nonstructural repair	$3,000	$5,000	$3,000	$6,000

References

1. U.S. Department of Energy Subcontract No. AFT-2-22435-01 under Contract No. DE-AC36-08GO28308 with the National Renewable Energy Laboratory.
2. "Consumer Price Index," United States Department of Labor Bureau of Labor Statistics. http://www.bls.gov/cpi/.