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Comparative Assessment of Direct Drive High Temperature Superconducting Generators in Multi-Megawatt Class Wind Turbines

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October 2010

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Abstract

This paper summarizes the work completed under the CRADA between NREL and American Superconductor (AMSC). The CRADA combined NREL and AMSC resources to benchmark high temperature superconducting direct drive (HTSDD) generator technology by integrating the technologies into a conceptual wind turbine design, and comparing the design to geared drive and permanent magnet direct drive (PMDD) wind turbine configurations. Analysis was accomplished by upgrading the NREL Wind Turbine Design Cost and Scaling Model to represent geared and PMDD turbines at machine ratings up to 10 MW and then comparing cost and mass figures of AMSC's HTSDD wind turbine designs to theoretical geared and PMDD turbine designs at 3.1, 6, and 10 MW sizes. Based on the cost and performance data supplied by AMSC, HTSDD technology has good potential to compete successfully as an alternative technology to PMDD and geared technology turbines in the multi megawatt classes. In addition, data suggests the economics of HTSDD turbines improve with increasing size, although several uncertainties remain for all machines in the 6 to 10 MW class.

Introduction

Background

Recent trends in wind energy have shifted toward larger projects using bigger turbines because a reduced cost of energy (COE) is associated with increased size. Historically, the cost of wind energy decreased as turbines grew larger; the result of enhanced engineering design that reduced component masses and costs, improved reliability, decreased operation and maintenance (O&M) costs, and optimized balance of station (BOS) components.

The trend toward larger turbines is expected to continue, particularly with offshore projects where physical size restrictions are less of an impediment. Offshore projects are anticipated to utilize larger turbines to take advantage of economy of scale. Currently, offshore projects place larger turbines in shallow coastal waters, where the wind resource is typically superior to onshore wind resources, thus yielding higher energy production. However, due to the offshore location of these turbines, the associated operations and maintenance (O&M) and BOS costs are typically higher.

Currently, the world's largest installed wind turbines, on and offshore, have rotor diameters reaching 127 meters and nameplate capacities of 5 to 6 MW, though many manufacturers are in the process of designing significantly larger machines. American Superconductor (AMSC), a worldwide leader in high temperature superconductor (HTS) technologies and products, who is also a leader in wind power system engineering, recently teamed with AMSC Windtec, a wholly owned subsidiary of AMSC, a leader in wind turbine design, to develop 3.1, 6, and 10 MW high temperature superconductor, direct drive (HTSDD) generator wind turbine designs as focused cases. The HTSDD generator design is a result of work sponsored by the National Institute of Standards and Technology (NIST) Advanced Technology Program (ATP). AMSC Windtec developed key technologies for low cost 10 MW class HTSDD generators, in a joint venture partnership with TECO Westinghouse Motor Company (TWMC), a leader in rotating machine manufacture.

AMSC and the National Renewable Energy Laboratory's (NREL) National Wind Technology Center (NWTC) selected point designs derived from the AMCS proprietary conceptual design portfolio of the full wind power system. NWTC led the systems analysis, economic modeling, and benchmarking in a parallel Cooperative Research and Development Agreement (CRADA). This provided specific point designs for the wind turbine system to assess the system's cost and cost of energy (COE). Results from the CRADA provided the vision for the next step, which is a demonstration program for a full wind turbine system.

The main purpose of this CRADA was to combine the NREL and AMSC resources to benchmark HTSDD generator technology by integrating the technologies into a conceptual wind turbine design, and comparing the design to geared drive and permanent magnet direct drive (PMDD) wind turbine configurations. The mutually beneficial relationship allowed NREL to gain an understanding of the current state-of-the-art HTSDD generator technology from AMSC. The NREL relationship provided AMSC with valuable knowledge and implementation through NREL's analysis capabilities including its wind turbine system experience and cost modeling. Both AMSC and NREL gained a fundamental understanding of the potential for HTSDD generator technology to be economically applied to wind turbines.

The collaboration has long term benefits for both parties through the exchange of data and ideas.

While the development of HTSDD generators is in a nascent stage, the collaboration also shows potential for enhancing the development of future wind energy systems in the multi-megawatt class for land based systems as a result of lighter weight components that can be more easily lifted with conventional cranes. In addition, the HTSDD technology may have greater potential for offshore wind turbines in the 6 to 10 MW class, even the possibility of a new class of wind turbines designed to operate on floating foundations.

Objective

The primary objectives of this CRADA were to:

1. Further develop the NREL Wind Turbine Design Cost and Scaling Model to represent geared and PMDD turbines at machine ratings up to 10 MW
2. Compare cost and mass of AMSC's HTS wind turbine designs to theoretical geared and PMDD turbine designs at 3.1, 6, and 10 MW sizes

Approach

The analysis looks at three turbine designs: a geared, a PMDD, and a HTSDD turbine. The geared and PMDD turbines were chosen because they are the two most prominent turbine designs installed today. They are indicative of two distinct technology paths that the industry may take once wind turbine production becomes more common in the 6 to 10 MW classes. For simplicity, all turbines compared in this analysis assume a standard three-bladed, up wind configuration with the rotor/nacelle assembly situated on a tubular tower.

Preliminary results indicated that a more detailed comparison of drivetrain components, through scaling relationships, would provide the greatest value to both parties of the CRADA. This was based on the assumption that all turbines would use the same rotor and tower. A more detailed explanation of why this assumption was made is reviewed in the Assumptions for Comparison section. Until further data indicates an alternative approach is warranted, it is assumed that the BOS costs for all turbine designs is the same in each power rating across all three drive train configurations.

It was assumed that the large size of the major components, such as blades and towers, would make onshore transportation exceptionally expensive. Additionally, AMSC's design choice of a relatively high tip speed resulted in higher sound emissions that could limit onshore locations due to proximity to residences. Therefore, only offshore turbines are considered in this study since transportation size issues and sound emissions are much less of a factor.

The NREL Cost and Scaling Model

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 by researchers at the University of Sunderland in the UK resulted in a set of scaling tools for machines with rotor diameters ranging from 15 to 80 meters [1]. This report contained valuable models to predict the impact of machine size on turbine components.

Beginning in 1999, the U. S. Department of Energy (DOE) began its WindPACT projects. These projects were focused on determining the potential technology pathways that would lead to more cost-effective wind turbine designs. One of the 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. The WindPACT projects 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 summarized the scaling results up to the time of its completion in June 2002. The two alternative drive train design studies extended this work, each by exploring a number of alternative drivetrain (gear box, generator, and 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 the Low Wind Speed Technology (LWST) projects [9]. 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. All LWST subcontracts have been completed [9], 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.

Beginning in late 2005, researchers at NWTC 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). The second purpose of this work was to provide a baseline tool for evaluating the impact of machine design and growth on the 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 compiling these relationships into a computer model and comparing them to current technology, a number of deviations were noted between this 2002 model and current trends. 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.

Early Version Cost and Scaling Model Description

The DOE/NREL cost and 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 address all potential wind turbine configurations; rather, it focuses on those configurations that are most common in the commercial industry at the time of the models first creation. 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. All cost scaling relationships were developed in a 2002 dollar basis for consistency. Most of the data originated in a 2002 dollar. Where cost data were available from different years, they were converted to 2002 dollars before the cost and scaling factors were developed. Cost data are based on a mature design and a 50 MW wind farm installation, with mature component production [10]. The model employs an algorithm to escalate component costs to alternate dollar year bases using Producer Price Indices at the manufactured component level.

Much of the data used to develop scaling functions for geared machines of greater than 1 to 2 MWs and most PMDD machines are based on conceptual designs and very sparse relationships. 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 [10]. The WindPACT studies were not intended to be 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, such as making single large components into multiple smaller components to ease transportation costs and restrictions. This model should be viewed as a tool to help identify such barriers and to quantify the cost and mass impact of design changes on components without such innovation. With expansion, the model can be used to help designers quantify the net value of the improvement by any component. 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.

Description of Cost and Scaling Model Improvements

General

In order to derive a COE comparison table with other wind turbines in the market space, it was necessary to be able to estimate the cost and mass of all major wind turbine components, and to know how these metrics change with variations in the turbine size. The objective of the CRADA largely consisted of updating NREL's cost and scaling model to represent these variations at turbine sizes between 3 and 10 MW. The original model was developed based on wind turbine sizes ranging from 750 kW to 5 MW. For this study, extrapolation to larger turbine sizes, up to 10 MW, was required. Therefore, the drivetrain component models were reevaluated.

When updating the model the following strategies and assumptions were made:

- Smooth functions were developed for updated relations, although the data from which they were derived may have contained discrete steps
- Other models and studies were checked to validate final scaling relations.
- Given that most costs were considered to be a function of mass, cost relations were largely unaltered
- Where data were available, scaling relations were checked against known commercial components
- Scaling relations represent production numbers, not the numbers expected for "one offs"
- All components were assumed to be of standard design, except where specified.

Low Speed Shaft

The formula used to establish the outer diameter of the low speed shaft was based on formulas for stress and strain at the main bearing where the shaft has the highest loads, adjusted from the University of Sunderland report [1]. Correction factors used in the equations were adjusted from their original state by selecting values more typical of larger turbines, to more accurately represent low speed shafts of turbines in the multi-megawatt class. The main shaft was assumed to be supported by a bearing at both ends, and to consist of a solid cylinder with a small hollow center and flanged ends for a bolted connection to the hub and gearbox. Low speed shafts for direct drive turbines and turbines utilizing a single bearing solution were not addressed. The inner-to-outer-diameter ratio of the main shaft was fixed at 0.1, with the length of the shaft fixed at 0.03*Rotor Diameter. The original formula did not take into account the addition of large connection flanges at both ends of the shaft; therefore, in this model, a term to add mass for the flanges was introduced. It was assumed that the mass of the flanges was 0.25*Mass of Shaft without the flanges [19]. A hollowness of 1 and safety factor of 3.25 was used in accordance with the original formulas.

The resulting expressions for the calculation of the low speed shaft's mass are as follows:

$$OD = \sqrt[3]{\frac{32}{\pi} * Hollowness * SafetyFactor * \left(\left(\frac{RotorTorque}{SteelYieldStress} \right)^2 + \left(\frac{BendingMoment}{SteelEnduranceLimit} \right)^2 \right)^2}$$

$$M_s = 1.25 * \frac{\pi}{4} * (OD^2 - ID^2) * L_s * \rho_s$$

$$M_f = 0.25 * M_s$$

$$Total\ Mass = M_s * M_f$$

With:

Ms = Mass of the shaft

Mf = Mass of the flanges

OD = Outer diameter of the shaft

ID = Inner diameter of the shaft

The cost of the low speed shaft retained the same relationship from the early version of the cost and scaling model; the relationship is 0.0998*(Rotor Diameter) $^{2.8873}$[10] in 2002 USD. This was developed from data provided in the WindPACT Rotor Study [6].

Direct Drive Generator

The mass of the direct drive generator was updated in the current model to adequately represent PMDD generators in the 3 to 10 MW size range, with a standard internal rotor design. The model does not currently have the ability to represent innovative PMDD generator designs such as "inverted generators" with internal stators. Industry point designs in the range of 1.5 MW to 7 MW were analyzed for size, mass, torque, and air gap shear stress to develop two scaling relations for a PMDD generator. The first scaling relation assumed that the generator would be constrained to no more than 4.3 meters in diameter due to transportation underpass and bridge limits. The second relation was developed to eliminate the diameter constraint for offshore applications where transportation restrictions are less of a constraint or for generators that might be manufactured in segments that can be assembled on site. For each relation, a set of points was calculated and plotted from 1 to 11 MW. A smooth curve fit was then developed for a PMDD from each data set to produce the following relations:

Constrained Diameter: Mass = 37.7*Rated Torque (Torque in kNm)

Unconstrained Diameter: Mass = 172.8*Rated Torque$^{0.8}$ (Torque in kNm)

A more detailed explanation of the PMDD generator calculations can be seen in Appendix C.

The cost of the PMDD generator was unaltered from its previous value of $219.33/kW in 2002 USD [10]. This multiplier was developed as a ratio between the WindPACT direct drive generator rated at 1.5MW and the WindPACT geared drivetrain generators derived in the WindPACT Alternative Drive Train Study [8].

Main Frame

Formulas from the University of Sunderland report [1] were used to calculate the mass of the main frame for geared turbines. Correction factors used in the University of Sunderland formula were adjusted by selecting values more typical of larger turbines, to more accurately represent machines in the multi-megawatt class. The calculations for the main frame mass were based on estimates of rotor thrust, torque, mass, and area. The masses for each factor, with a bedplate area of 0.5*(0.0825*Rotor Diameter)^2 and a bedplate weight factor of 2.86 for a modular design, were calculated as follows [1]:

Mass from Torque = Bedplate Weight Factor*0.00368*Rotor Torque.

Mass from Thrust = 0.00158*Bedplate Weight Factor*Max Thrust*Tower Top Diameter

Mass from Rotor Weight = 0.015*Bedplate Weight Factor*Rotor Mass*Tower Top Diameter

Mass from Area = 100*Bedplate Weight Factor*Bedplate Area

Total Mass = Σ of all Masses

The mass of the main frame was taken to be the sum of all mass inputs calculated above. Additional platform and railing mass and cost calculations from the early version of the NREL cost and scaling model remained at .125*Main Frame Mass and 8.7*Platform and Railing Mass, respectively, and were included in the total mass of the main frame assembly [10]. The main frame cost of 9.4885*Rotor Diameter$^{1.9525}$ was unchanged from the previous relation based on the WindPACT reports [6]. Base hardware costs are again unchanged from previous relations of 0.7*Main Frame Cost and included in the total Main Frame cost [10]. Main Frame calculations for PMDD machines assume that direct-drive machines need a smaller main frame that is more integrated into the direct-drive generator itself and therefore, the main frame cost and mass for direct-drive machines is 55% of that for a geared machine [8]. Final main frame mass outputs were then checked against industry data and WindPACT results [6] in the range of 750kW to 5MW.

Drive Train Efficiency Curves

Efficiency curves were established for alternative drivetrain designs to represent the differences in annual energy production between drivetrain design choices. Constant, linear, and quadratic style losses were modeled from the WindPACT Alternative Drive Train Study [8] for standard, single stage, multi drive (6 generators), and direct drive turbines.

Efficiencies were calculated as follows:

$$\eta = \frac{P - (C + L * P + Q * P^2)}{P}$$

With:

C = Constant losses

L = Linear losses

Q = Quadratic losses

P = (Power)/(Rated Power)

Except for the standard geared drivetrain, all generators were assumed to be a permanent magnet design. Drivetrain efficiencies for all four drivetrain configurations can be seen in Figure 1 below from 6% of rated power to 100% of rated power.

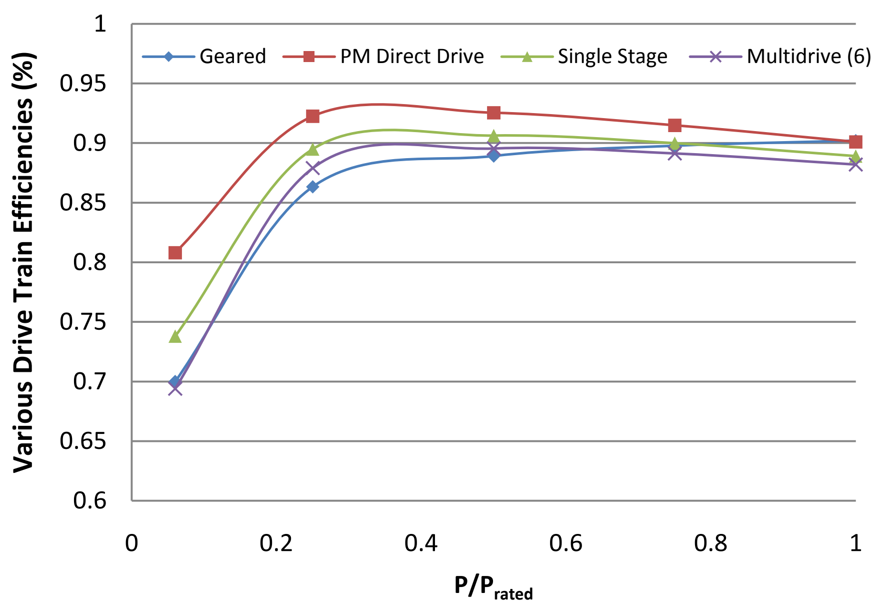

Figure 1: Drivetrain efficiencies for various drivetrain designs from 6% to 100% of rated power.

Industry Power Curve Data

Power curves for AMSC's three turbine sizes were added to the NREL cost and scaling model for an accurate comparison, of both annual energy production and capacity factor, to an idealized turbine. Industry power curve data, based on published power curve information, were also added to the cost and scaling model to calculate annual energy production for various industry turbines. Data from 69 turbines from 21 manufacturers, ranging from 550kW to 5 MW, were added to the model to provide a variety of industry turbines for comparison. The data can provide information for project planning as well as concept-to-industry comparisons and offers planners the ability to switch between various turbines to optimize site performance. Furthermore, design concepts and AMSC's turbines can be compared against market proven turbines. It should be noted, however, that these power curves were frequently derived from brochure graphics, and their representations provide only a general comparison between turbines and should not be used to represent precise turbine output. Official power curve documentation from manufacturers is required to fully assess and compare turbine energy production for a given wind regime.

Model Inputs

Turbine Design Parameters

To isolate the drivetrain configurations for comparison, turbine parameters were held constant for the three turbines in each MW class. Rotor parameters (Diameter, Cp, Tip Speed, and Tip Speed Ratio) and hub heights were all taken from the AMSC designs since they are representative of potential commercial designs. Rotor design parameters were chosen by AMSC based on the existing blade types on the market and the manufacturing capabilities of the potential suppliers. Therefore, an aggressive scale of rotor diameter was avoided, and only proven blade technology was used in the preliminary designs. As such, scenarios for prototypes with smaller diameters were assumed to be more realistic than big rotors requiring "beyond state-of-the-art" rotor blade technology (e.g., nominally blades beyond 75m in length). Therefore, turbine sites for the preliminary designs are assumed to be offshore with high wind regimes. This approach does not preclude further studies, in which longer blades with improved blade technology might be applied, resulting in bigger diameters and improved cost of energy on subsequent turbine designs. The turbine design parameters common to all configurations investigated in this report are shown in Table 1.

Table 1. Overarching turbine parameters used in all three design types.

	3.1 MW	6 MW	10 MW
Rotor Diameter (m)	115	127.4	149
Hub Height (m)	90	100	140
Max Cp	0.485	0.476	.495
Max Tip Speed m/s	75.0	81.8	89.7
Max Tip Speed Ratio	9.3	9.4	8.6
Rated Torque (kNm)	2584	5003	8842
Rated Speed (RPM)	12.46	12.27	11.5
Number of Blades	3		
Tower Design	Steel Tubular		
Foundation Type	Monopile		

AMSC Supplied Preliminary Designs

As part of the CRADA Task #1, AMSC Windtec supplied preliminary designs for wind turbines using AMSC HTSDD generators at the 3.1, 6, and 10MW power ratings. Cost and mass numbers were provided for the rotor assembly, drivetrain/nacelle assembly, tower, and turbine total for each MW class, as seen in Figures 2-3 and Table 2. Breakdowns for major components of each assembly were also provided.

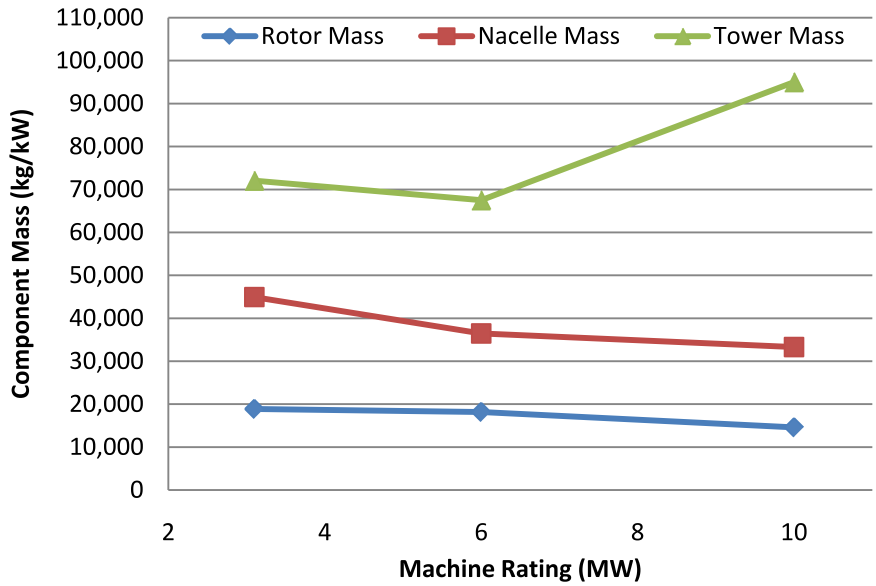

Figure 2. Rotor, nacelle, and tower mass for AMSC preliminary designs ranging from 3.1 to 10 MW.

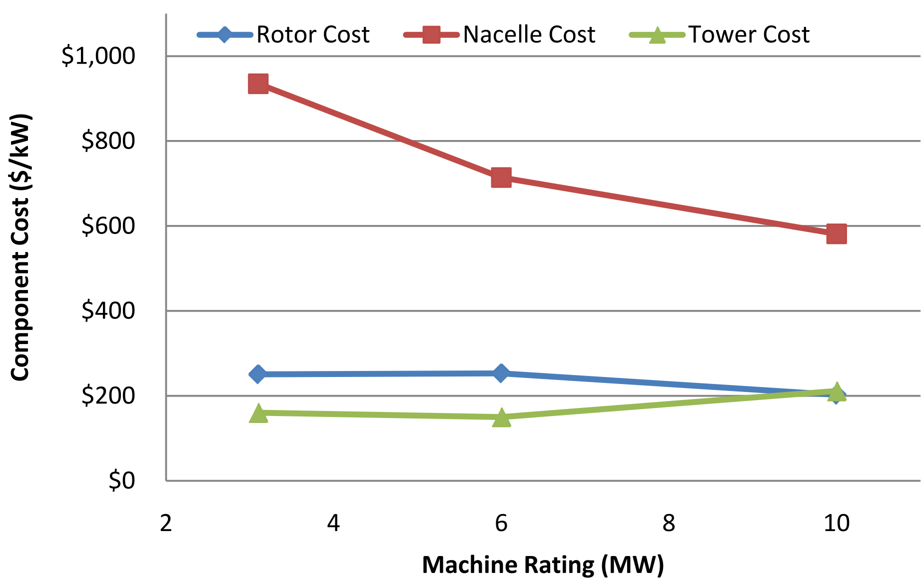

Figure 3. Rotor, nacelle, and tower cost for AMSC preliminary designs ranging from 3.1 to 10 MW.

Table 2. Rotor, nacelle, and tower mass breakdown for AMSC supplied turbines.

Mass (kg)	3.1 MW	6 MW	10 MW
Rotor Mass	58,502	108,967	145,892
Nacelle Mass	139,321	218,854	332,913
Tower Mass	223,390	405,060	950,000

Wind Characteristic Input Parameters

Wind characteristic parameters were held constant for all three turbine configurations. Wind characteristics corresponding to an IEC class I offshore wind farm were used. A hub height wind speed of 10 m/s was used for all turbines at all rating sizes with a vertical wind shear of 0.1 per second. Wind distributions were calculated using a Weibull probability and a Weibull K factor of 2.1. Availability for the turbines was estimated at 95% and array losses were set to 10%. Wind class parameters used for all three drivetrain design configurations are listed in Table 3.

Table 3. Wind characteristic input parameters used for all three drivetrain configurations.

	3.1 MW	6 MW	10 MW
IEC class	I		
V_{ave} at HH (m/s)	10		
V_{E50} at HH (m/s)	70		
Weibull K	2.1		
Wind Shear	0.1		
Array Losses	10%		
Availability	95%		

AMSC Preliminary Design Comparison

Assumptions for Comparison

Calculations for the geared and PMDD turbines were performed using NREL's updated Cost and Scaling Model. Data for the HTSDD machines were provided by AMSC as preliminary designs at each turbine size. Therefore, the scaling of the PMDD and geared turbines may not include design innovations of a comparable level to that of the AMSC HTSDD design. The cost and scaling model does not calculate representative main shaft masses or costs for direct drive configurations due to a lack of detailed design data from commercial machines. For this reason, it is assumed that the main shaft for the PMDD machine will have the same cost and mass as that of the AMSC designs.

Large scale blade technology has not yet been developed and demonstrated for machines at the 10 MW level; therefore, rotor diameters, masses, and costs for both the baseline turbines and the superconducting turbine use the numbers provided by AMSC for the HTSDD turbine. Similarly, all machines in the comparison use tower cost and mass estimates associated with the superconducting turbine. It is possible that the tower mass between turbines with different tower top masses could vary slightly, though heavier nacelle/rotor assemblies do not necessarily require heavier towers. The largest design factor for the tower is based on overturning moment associated with the thrust on the rotor. Though the tower top mass is taken into account for buckling calculations, it is not the largest design driver. The nacelle mass does however affect the natural frequency of the tower and should be taken into account during the dynamic analysis [11]. Because tower design takes into consideration many dynamic inputs, attempting to account for them in the current version of the cost and scaling model was determined to be beyond the scope of this project.

Component Comparisons

Drive Train/Nacelle Assembly

With tower and rotor masses held constant across all configurations, the only variation in cost or mass that can be seen is in the Drivetrain/Nacelle assembly. A significant overall drivetrain mass difference is observed across all MW ratings between the PMDD turbine and the Geared and AMSC turbines as seen in Figure 4. The geared turbine and the AMSC HTSDD turbine exhibit similar masses across machine ratings, but it appears that the AMSC turbine has a slight mass advantage at the larger machine sizes. The significant mass difference between the PMDD turbines and that of the geared and AMSC turbines is heavily dependent on the PMDD generator, which could see significant mass reduction, as discussed later in the generator portion of the Component Comparison section.

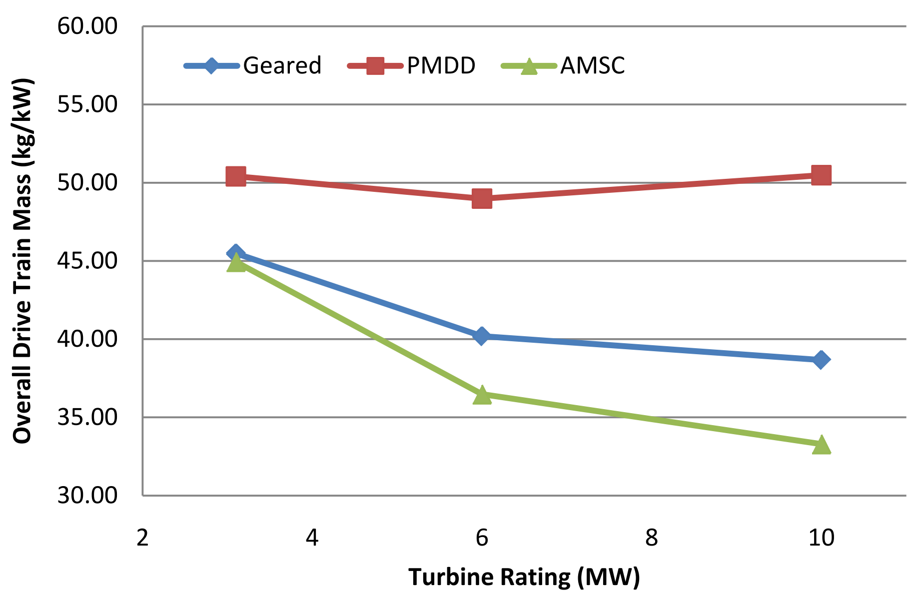

Figure 4. Comparison of overall drive train mass for geared, PMDD, and AMSC turbines.

However, the variation in mass does not directly correlate to a reduction in the drivetrain cost. The overall drivetrain costs for all three machine types, as seen in Figure 5, lie relatively close to one another, though the cost of the drivetrain for the AMSC turbine rises at a lower rate than that of the other two turbines. The geared and PMDD turbines represent simple scaling of technology to larger sizes. Design innovations targeted to reduce mass as the size increases are not included in the basis scaling relationships. The AMSC turbines represent more detailed preliminary designs at each MW rating, rather than simple scaling of technology to larger sizes.

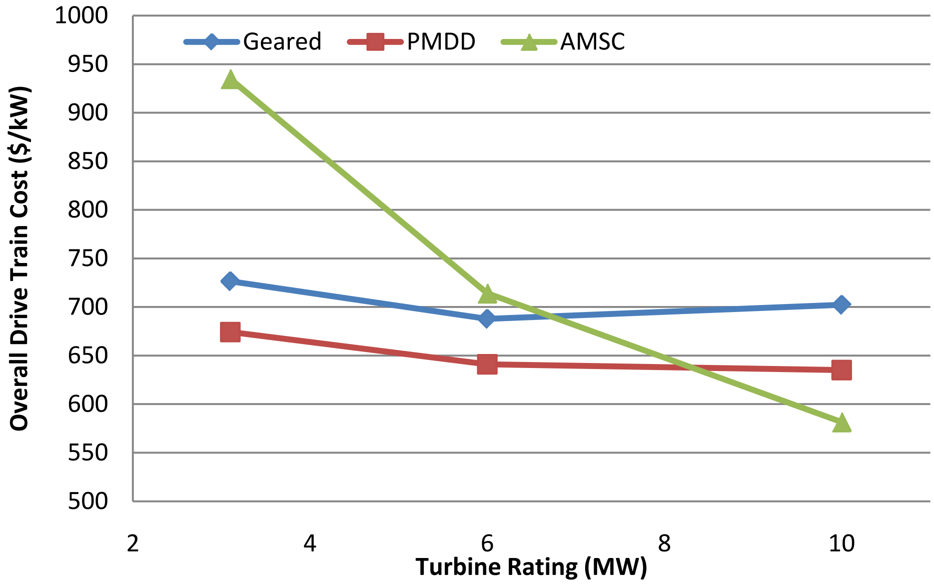

Figure 5. Comparison of overall drive train cost for geared, PMDD, and AMSC turbines.

Generator

The largest contributor to the overall drivetrain mass for direct drive machines is the generator. Due to the lack of a gearbox, direct drive generators must operate at much lower rpm's. This requires the generator to be larger and more robust to handle the increased torque loads. The comparison between direct drive HTS and PM direct drive generators was based on an imposed shipping design constraint of 4.3 meter stator diameter. Both machines derive benefit from the selection of a larger diameter. The maximum reasonable diameter for an HTS generator is generally smaller than a similar PM machine. The design literature [21, 22] proposes diameters up to 10 meters for PM machines. If the design literature is correct, the lightweight, 10 m PM machine is still greater in weight, by a factor of two, than the 5 m diameter HTS machine. A complete comparison between HTS and PM machines would require a family of curves at varying diameters and include the cost and weight impact on the integrated nacelle design, which is beyond the scope of this study. For a reasonable range of generator diameters, HTS machines will be lighter weight. The full load efficiencies for HTS and PM machines are comparable and both can be preferentially optimized for size, weight, and/or efficiency. The results, shown in Figure 6, demonstrate this. The PMDD generator is the heaviest, the AMSC HTSDD generator is second heaviest, and the geared turbines generator is the lightest. The roughly 50% reduction in mass between the PMDD and AMSC HTSDD generators at 10 MW is one of the core advantages of HTS generators.

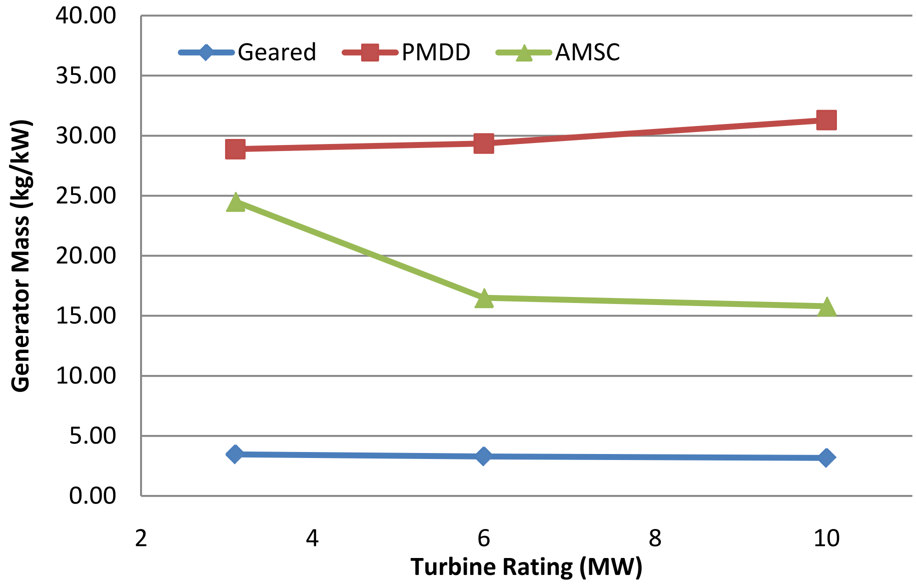

Figure 6. Comparison of generator mass for geared, PMDD, and AMSC turbines.

It should be noted that the PMDD mass figures presented in Figure 6 are of a design with the stator on the outside and the rotor on the inside of the generator. With this design, significant mass is needed for the support structure to maintain a constant air gap. Several turbine manufacturers have designs that attempt to avoid this increased mass by developing innovative designs such as an "inverted generator," in which the stator is on the inside and the rotor is on the outside of the generator. Preliminary numbers from a few manufacturers have indicated that these innovative designs can be of comparable mass as the AMSC design at ratings around 3 MW [26].

There is no data available from manufacturers regarding operating speed and efficiency for the advanced designs and a comparison between the conservative low speed and high efficiency 3MW designs in this paper cannot be made. The PMDD generator mass presented in this paper may be higher than typical direct drive turbines due to the turbine rotor size and operating speed at 3MW. With a large turbine rotor, the operating speed of the generator must be reduced to avoid the associated noise of high tip speeds. The reduction in generator speed increases the rated torque and, consequently, the size and mass of the generator. Ideally, PMDD generators would benefit from a smaller rotor as compared to a geared or HTSDD design. However, this analysis is a comparison of identical turbines with only alterations in the drivetrains from turbine to turbine. The 3 MW designs in this paper were on the low end of a set of curves that applied to medium voltage high torque machines associated with a projected market for HTS generators above 5 MW. The advanced PMDD designs recently introduced into the market are low voltage. Modification to low voltage machines may be needed if they increase to medium voltage, which is projected for the 10 MW class market. An analysis of idealized turbine rotor-to-generator configurations for each turbine is beyond the scope of this study.

Though AMSC's HTSDD generator shows a significant reduction in mass, the advanced HTS technology used to achieve the mass reduction is more expensive than standard technology for generators. Figure 7 demonstrates this cost impact. It shows the AMSC generator cost as slightly higher than that of the PMDD machine for lower MW classes and roughly the same for the largest MW class. However, these curves could change significantly, if the price of copper or NeFeB, used in the PMDD generators, increases as it has for the last several years or if the cost of HTS generators is driven down by advancements in this relatively new technology.

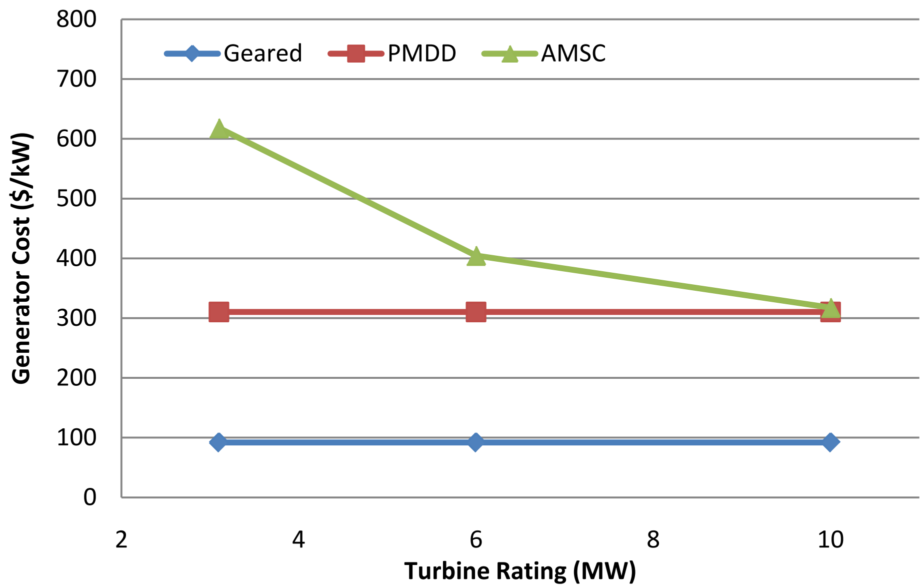

Figure 7. Comparison of generator cost for geared, PMDD, and AMSC turbines.

Main Frame

The largest contributor to the overall mass of the drivetrain, for standard gear driven turbines, is the main frame. Spanning nearly the entire base of the nacelle, the main frame must support the gearbox, generator, and many other drivetrain components in a geared turbine. A direct drive machine, such as the PMDD and AMSC HTSDD turbines, is generally self supporting but does require a limited main frame. As described earlier, it was assumed that the geared turbine required a much heavier main frame than direct drive designs. The cost and scaling model rough estimates for the direct drive main frame are 55% of that of a geared turbine's main frame [8]. In comparison to the AMSC main frame, the PMDD main frame is probably underestimated considering that it must support a significantly larger and more massive generator. With such sparse data for PMDD turbine main frames, extrapolation of scaling relations beyond the range of 3 MW may not be accurate. The main frame of a PMDD turbine is integrated into the drivetrain, thus there is a great deal of potential for the design to affect the mass and cost of the main frame. A more detailed design of an integrated direct drive generator, with support structure, is ultimately necessary to determine an accurate mass and cost of a direct drive main frame. A graphical representation of this comparison can be seen in Figure 8.

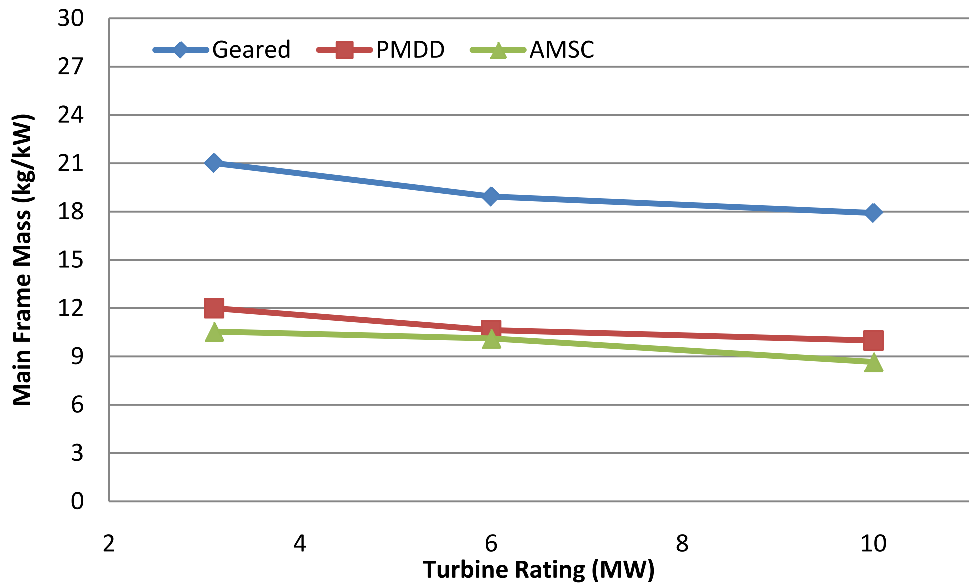

Figure 8. Comparison of main frame mass for geared, PMDD, and AMSC turbines.

Associated costs for the main frames vary, most likely because of the lack of detailed design data for main frame costs in direct drive turbines. The cost and scaling model calculates the cost of a direct drive main frame, including railings and other associated hardware, based on two different point designs from the WindPACT Alternative Drive Train Study [8], one at 1.5 MW and the other at 3 MW. Again, an extrapolation further than 3 MW, based on two points, may not be very accurate. Based on the mass relationship shown in Figure 8, it was expected that the geared main frame would show a notably higher cost than that of the direct drive turbines and that the PMDD turbine would have a slightly more expensive main frame than that of the AMSC HTSDD. However, Figure 9 does not support this. Instead, it shows the AMSC HTSDD main frame at a higher cost than that of the PMDD main frame. This discrepancy is likely the result of the PMDD main frame cost being calculated from a model, while the AMSC HTSDD main frame cost is an actual design estimate.

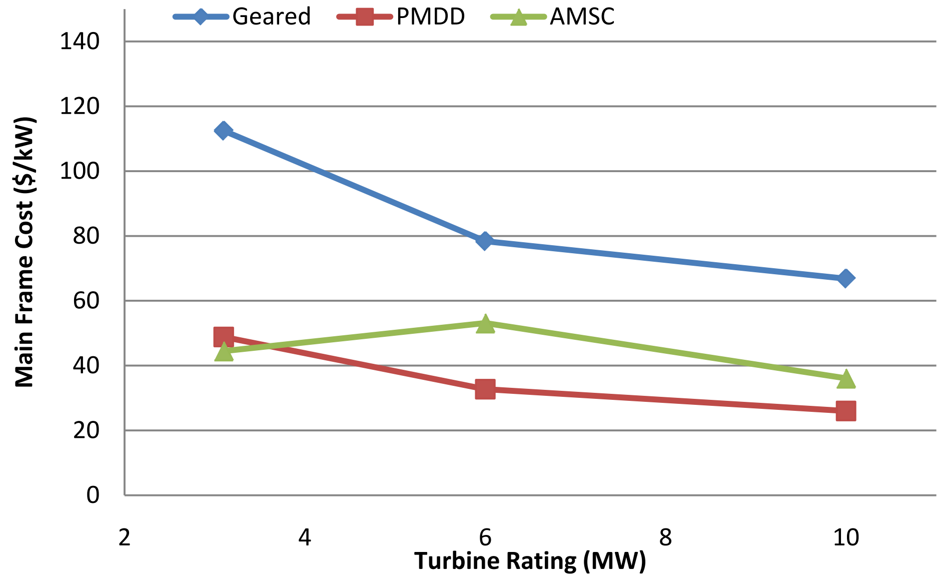

Figure 9. Comparison of main frame cost for geared, PMDD, and AMSC turbines.

Low Speed Shaft

The low speed shaft for a geared turbine is much different than a low speed shaft for a direct drive turbine. A geared turbine uses a low speed shaft and its length is much longer than its diameter. The opposite is usually true for direct drive turbines. Due to the lack of detailed design data for commercial low speed shafts in direct drive turbines in the cost and scaling model and because of their integrated designs, the PMDD turbine was assumed to use the same low speed shaft as that provided for AMSC's HTS turbine. The differences in low speed shaft masses can be seen in Figure 10.

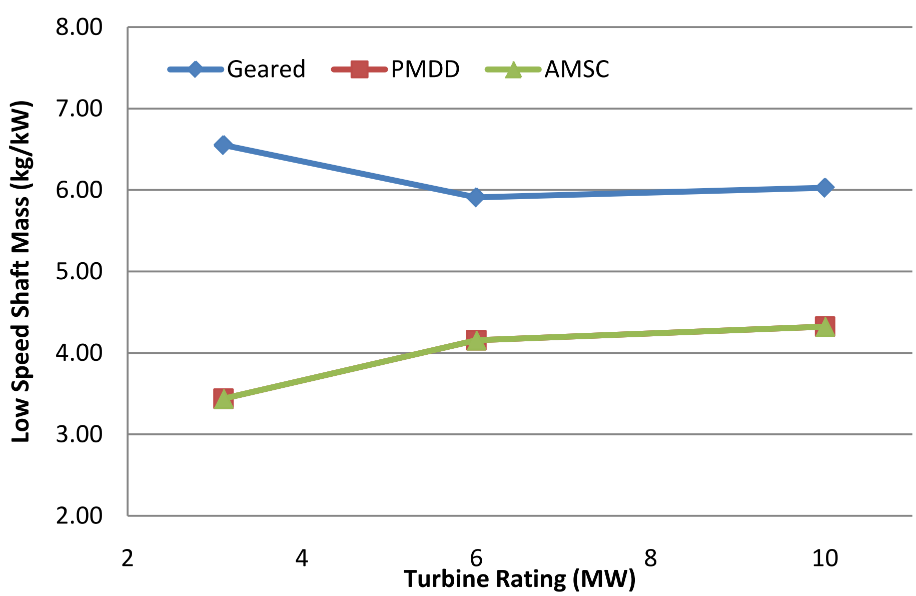

Figure 10. Comparison of low speed shaft mass for geared, PMDD, and AMSC turbines.

Figure 11 shows a similar pattern for the cost when compared to the mass due to the relatively simplistic design of low speed shafts, thus the relation between the cost of the shafts emulates the relation between the mass of the shafts.

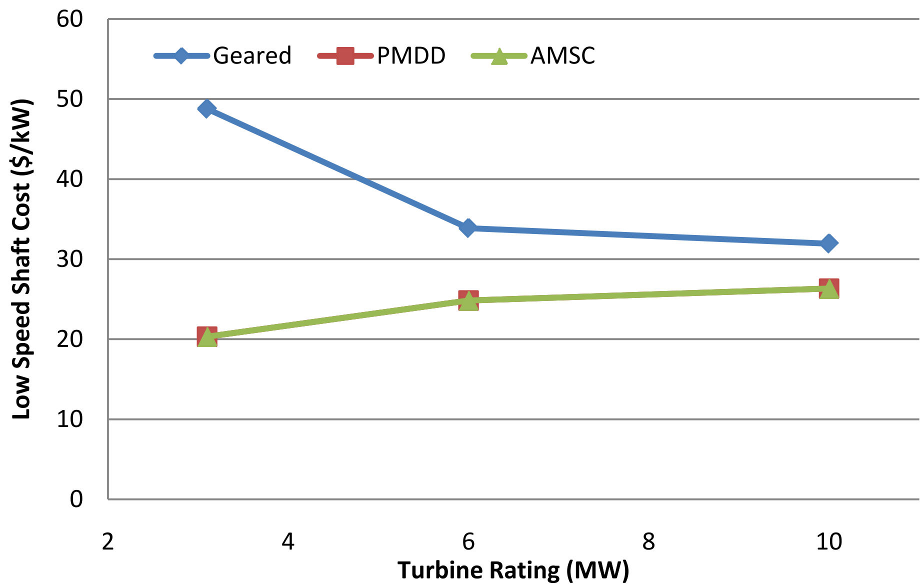

Figure 11. Comparison of low speed shaft cost for geared, PMDD, and AMSC turbines.

Gear Box

The main difference between a geared turbine and a direct drive turbine is the inclusion or exclusion of a gearbox. The gearbox allows for a much lighter, smaller, and cheaper generator, but it introduces another point of failure and cost to the turbine. Figures 12 and 13 show the associated mass and cost, respectively, for gearboxes in the 3-10 MW range.

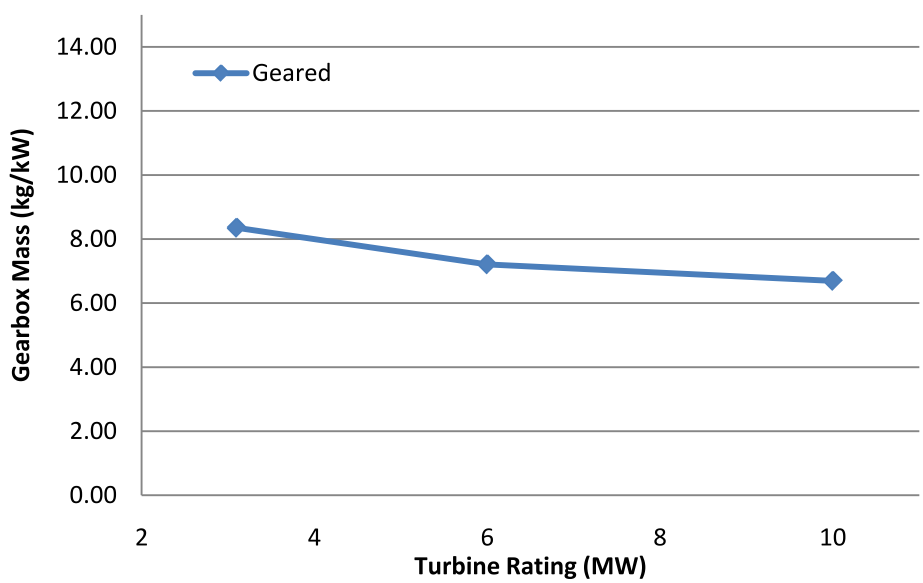

Figure 12. Gearbox masses for turbines 3-10 MW.

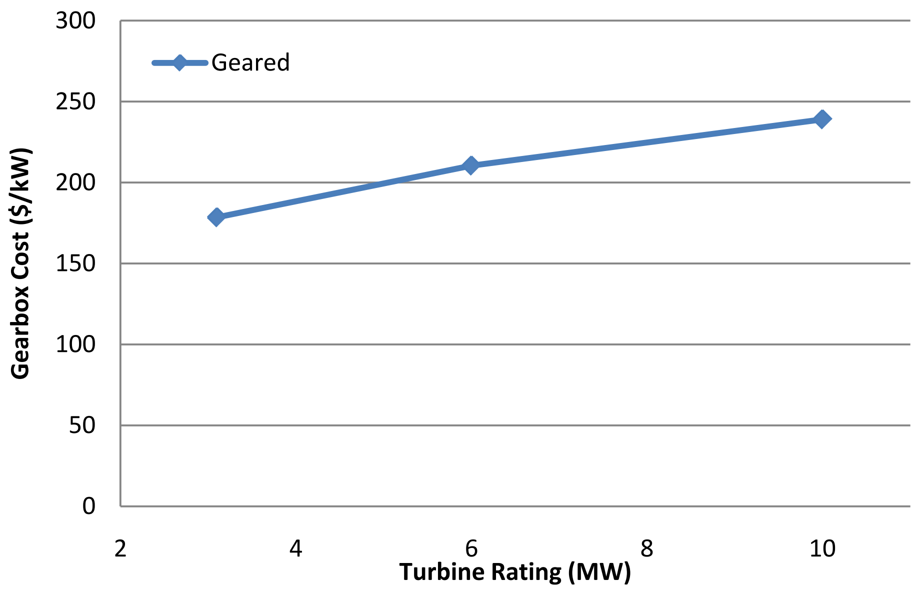

Figure 13. Gearbox costs for turbines 3-10 MW.

System Comparisons

It is important to compare wind turbine concepts in a way that captures the full suite of cost implications including: capital cost, operating cost, and energy production. The levelized cost of energy (LCOE) is a typical metric used to compare wind turbine systems because it captures both capital investment and operational impacts over the economic life of the project. The fixed charge rate (FCR) approximates the finance cost, including interest and taxes over the economic life of the project.

The total LCOE is calculated using the following equation [10]:

$$LCOE = \frac{(FCR \times ICC)}{AEP_{net}} + AOE$$

where $LCOE \equiv$ 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

$\equiv LLC + \frac{(O\&M + LRC)}{AEP_{net}}$

$LLC \equiv$ land lease cost

$O\&M \equiv$ annual operating and maintenance (O&M) cost

$LRC \equiv$ annual replacement/overhaul cost

In this analysis, the comparison was focused on the drivetrain components, assuming that balance of system costs and operation costs would be similar for all three turbine concepts studied (Drivetrain Cost of Energy Section). For reference, an estimated total system LCOE for projects anticipated in the U.S. today is presented along with a discussion of the implications in the simplifying of assumptions made in this analysis (Total Levelized Cost of Energy Section).

Drivetrain Cost Of Energy

Isolating the drivetrain component in the LCOE equation by eliminating the operating cost yields the following equation [10]:

$$LCOE_{dt} = \frac{(FCR \text{ x } ICC_{dt})}{AEP_{net}}$$

where $LCOE_{dt}$ ≡ levelized drive train cost of energy (\$/kWh) (constant \$)

FCR ≡ fixed charge rate (constant \$) (1/yr)

ICCdt ≡ initial drive train capital cost (\$)

AEPnet ≡ net annual energy production (kWh/yr)

With overall drivetrain/nacelle assemblies estimated to have similar masses along with the assumption of an equivalent rotor and tower for each turbine configuration, it was assumed that there would be no difference in installation equipment needed among the drivetrain designs. Because installation equipment and all other balance of station (BOS) costs would be the same, this analysis assumed that the only differences in the cost of energy (COE) would result from the drivetrain configuration. This impacts the drivetrain cost and annual energy production (AEP). The difference in drivetrain efficiencies, displayed in Figure 14, can greatly affect the AEP, displayed in Table 4 below. Table 4 summarizes the differences in AEP between drive train design and turbine size.

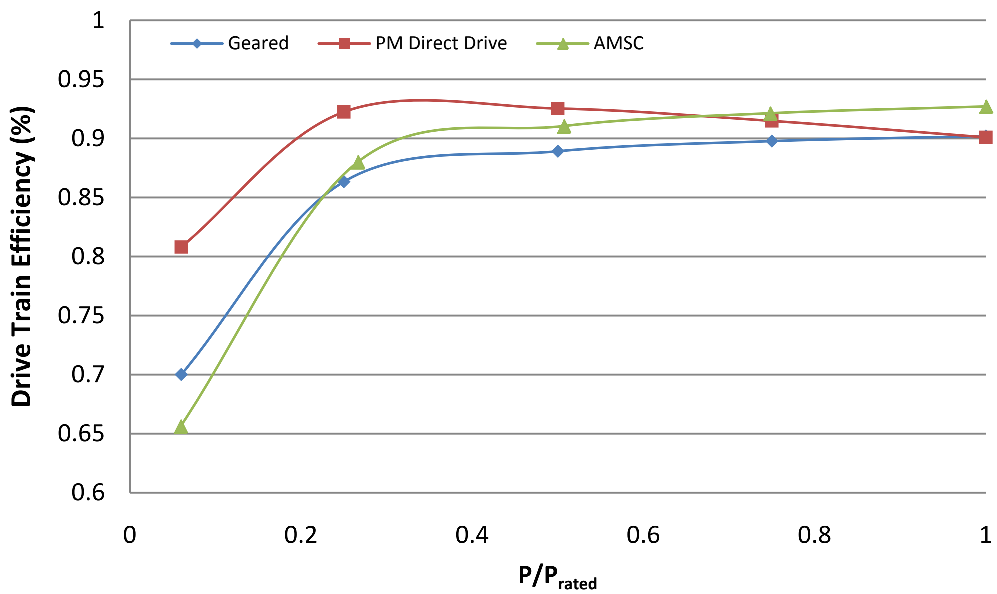

Figure 14. Efficiency differences between analyzed drivetrains

Table 4. Annual energy production in gigawatt hours

AEP (GWh)	3.1 MW	6 MW	10 MW
Geared	14.1	22.4	35.8
PMDD	14.3	22.8	36.4
AMSC	14.2	23.4	37.0

The difference in AEP coupled with the difference in the capital cost for each drivetrain leads to the approximate levelized cost, in $/kWh, for each drivetrain. One should note that either a higher AEP or a lower capital cost for the drivetrain, or the combination of both, will lead to a lower levelized drivetrain cost. These costs were calculated using a 14% Fixed Charge Rate (FCR). This was based on the assumption, in the project finance structure, that includes a reduced risk associated with a DOE loan guarantee for an offshore wind energy project in the U.S. A description of the FCR assumptions is included in Appendix A. All calculations do not take into account production or tax subsidies, which would lower the levelized drivetrain COE. The differences in LCOE of the drivetrain configurations are shown in Figure 15.

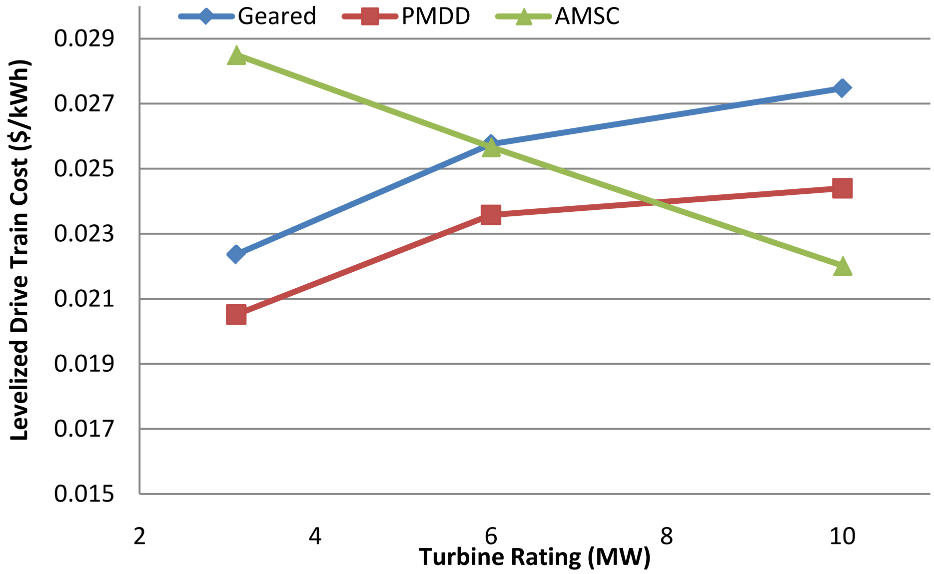

Figure 15. Comparison of levelized drive train costs for geared, PMDD, and AMSC turbines.

Total Levelized Cost Of Energy (LCOE)

The full system LCOE takes the AEP, land lease cost, major component replacements, O&M, BOS, and drivetrain cost differences into account. The AEP and drivetrain cost differences were compared in the previous section at the drivetrain component level. Other costs that could affect the comparison among turbine configurations are associated with BOS and O&M costs.

O&M costs for offshore turbines contribute significantly to the wind farm's LCOE, leading many manufacturers to target this area for cost reductions through innovation. Drivetrain design differences can lead to different O&M practices. For example, direct drive turbines do not need periodic oil changes for the gearbox because the direct drive configuration does not utilize a gearbox, reducing the frequency of visits to a particular turbine. For offshore wind projects, high reliability is imperative because harsh environment operating conditions significantly impact the ability to access and service turbines for unscheduled maintenance. It is anticipated that the elimination of O&M costs associated with gearbox maintenance will increase the geared turbine's LCOE relative to the PMDD and HTSDD turbine LCOE. It is possible that the increased cooling system requirements that are necessary for HTSDD turbines may lead to increased maintenance costs, in which case the LCOE differences between the HTSDD turbines and the geared and PMDD turbines would be reduced. Due to the lack of O&M cost data for offshore HTSDD turbines and, to a lesser extent, PMDD and geared turbines, these operational cost differences were not quantified in this analysis.

Major component replacements (represented as LRC in the LCOE equation) have also proven to be a significant contributor to a wind farm's LCOE. For conventional geared turbines, the gearbox is a major component that tends to need multiple replacements before the end of the turbine's designed lifetime due to unresolved design problems. The industry has learned from these problems over the past two decades. Wind turbine manufacturers, gear designers, bearing manufacturers, consultants, and lubrication engineers have worked together to improve load prediction, design, fabrication, and operation. This collaboration has resulted in internationallyrecognized gearbox wind turbine design standards [13]. Despite reasonable adherence to these accepted design practices, wind turbine gearboxes have yet to achieve their design life goals of twenty years, with most systems requiring significant repair or overhaul well before the intended life is reached [14, 15, 16]. Since gearboxes are one of the most expensive components of the wind turbine system, the higher-than-expected failure rates are adding to the cost of wind energy. In addition, the future uncertainty of gearbox life expectancy is contributing to wind turbine price escalation. Turbine manufacturers add significant contingencies to the sales price to cover the warranty risk due to the possibility of premature gearbox failures [12]. In addition, owners and operators build contingency funds into the project financing and income expectations for problems that may show up after the warranty expires [17]. It is anticipated that the increased cost associated with the gearbox replacement issues will increase the LCOE of geared turbines relative to the LCOE of HTSDD and PMDD turbines. Direct drive wind turbines circumvent these cost escalations by excluding the gearbox from the design, and rely on the assumption that the generator will have fewer maintenance issues. However, if future direct drive configurations present issues that would also need major component replacements, the difference in LCOE may not be as pronounced.

For this analysis, it was assumed that the rotor size and weight dominated the BOS cost by dictating the type of equipment required for installation of the offshore wind project. Innovative concepts for transport and installation of offshore wind turbines could result in more modular approaches, where weight difference at the drivetrain component level could become more important. In this event, the different BOS cost for similar turbines, with different drivetrain configurations, would impact the LCOE. Development of a detailed BOS cost model to conduct this type of comparison was outside the scope of this analysis.

For reference, an estimated system LCOE for anticipated offshore projects in the U.S. is presented here, and in more detail in Appendix B. Review of proposed U.S. offshore projects and published data from existing and proposed European offshore wind projects indicates that an average all-in installed capital investment of $4,131/kW is representative of projects planned for installation in 2010. Estimated LCOE was calculated for a 3.6 MW wind turbine, with a 107 meter rotor diameter at 80 meter hub height, operating in a class 6 wind regime with an average wind speed of 8.4 m/s at 50 meters. In this wind regime, an AEP of 12.4 GWh is expected. The foundation is a monopile, 25 km from shore, in 10 meter deep water (considered shallow offshore). Based on these assumptions, it is estimated that an offshore wind farm installed in 2010 would see an LCOE of approximately $0.19/kWh, when using a 14% FCR. It is expected that the 3.1 MW class turbines studied in this report will exhibit similar LCOE, with slight differences as explained in the Drivetrain Cost of Energy section, associated with the different drivetrain configurations.

Conclusions and Recommendations

The main objective of the CRADA was to model expected industry turbines at the 3.1, 6, and 10 MW classes for comparison of components and LCOE differences with respect to AMSC's HTSDD wind turbine designs. Geared and PMDD wind turbine designs that represent conventional wind turbine configurations in the 3 MW class with known track records were used as scaling basis for the expected industry turbines at these larger MW classes. An assessment of how the HTSDD designs from AMSC compare to the conventional industry turbines was a key goal of the CRADA to determine if the concept of a HTSDD generator is economically feasible for wind turbines.

Based on the comparisons made to the conventional PMDD and the geared configurations, HTSDD turbines show a strong potential to be competitive with other drivetrain concepts, particularly for larger turbine sizes. Based on the cost and performance data supplied by AMSC, HTS technology has good potential to compete successfully as an alternative technology to PMDD and geared technology turbines in the multi megawatt classes. In addition, the economics of HTSDD turbines improve with increasing size, although several uncertainties remain in the cost model. The model for the support structure and low speed shaft for PMDD turbines is insufficient and, therefore, could create some error but NREL did not feel that these errors would be substantial enough to change the conclusion about HTS technology. An analysis to further understand the BOS implications was not completed and could also contribute to some uncertainty. One effect left for future work is the impact that reduced drivetrain weight would have on the overall BOS costs.

The new technology inherent in HTSDD turbines introduces new components, which do not have a long history of operation, particularly in wind turbines and could potentially introduce new modes of failure. The uncertainty in the operating costs of HTS technologies should be taken into account in assessing the O&M differences between different drivetrain technologies. The HTS technology does show an advantage in weight, efficiency, and scalability. HTS may also have a greater potential for cost reduction due to innovations that may come from maturation of this relatively less developed technology and its application to wind turbines.

Perhaps the most significant motivation for the development of a superconducting wind turbine generator is the assertion by AMSC and others [23, 24, 25] that this technology will enable the construction of larger wind turbines. Larger wind turbines mean fewer turbine installations, which could result in lower balance of station costs. As noted in Appendix B, the installed capital cost is on the order of 4.1 million per MW using the example 3.6 MW rating. Of this cost, 34% is uncertainty and estimated risk. If we assume these items distribute evenly between the wind turbine and balance of system, we can estimate that the wind turbine is 45% of the installed cost and the balance of station is 55% of the installed cost. On a cost per rating basis, balance of station costs could be lower for wind farms using fewer large turbines. Since balance of station is the dominant installed cost, a 10 MW should result in a reduction in the installed cost per MW, relative to 3.6 MW. Additional work is required to quantify this benefit.

Significant work is still needed in the development of the NREL Cost and Scaling Model for a complete comparison of turbine COE. As stated earlier, the entire BOS portion of the model needs more data in order to accurately quantify the benefits of turbine design choices, for both land based and offshore applications. Additionally, the cost calculations for the low speed shaft and the generator should be altered to be a scaling relation of mass and torque respectively, as those parameters will ensure a more accurate analysis. Scaling relations for other cost components could also use some alteration to a relation that would ensure a more accurate analysis.

The National Renewable Energy Laboratory recommends that American Superconductor Corporation produce a HTSDD generator in the 3 to 6 MW scale for a dynamometer test as a next step to development. A 3 to 6 MW scale HTSDD generator shows potential to be competitive with other drivetrain configurations and provides a pathway to market with current wind energy technology without taking the risks associated with a 10 MW platform. Although the study did indicate a slight benefit in scaling the HTS drivetrain to 10 MW, the cost advantages are not substantial enough across the system to warrant the added risk entering the market at a size where other non drive train components are not currently available. A dynamometer test would provide a deeper understanding of operational issues and would supply AMSC with valuable experience.

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Appendix A. Fixed Charge Rate Calculation

Given the same initial turbine costs, installed costs, and general conditions, the two COE calculations in this estimation differ only in the assumption of the fixed charge rate (FCR). FCR allows simplified COE estimates by relying on a single coefficient, calculated from comprehensive cash flow modeling. The FCR reflects finance charges, debt or equity repayment, construction financing, and cost of capital (among other factors). FCR is representative of a specific ownership and cash flow structure and may vary over time. However, a fixed value is required for comparisons across technologies and a composite or average FCR may be used to represent an array of financing structures. Both scenarios assume 3% inflation. Scenario one assumes a 30% return on equity (ROE), and scenario 2 assumes a 20% ROE. The ROE is high in both scenarios to account for risk associated with the initial offshore wind projects. The financing scenario for the land-based reference turbines have a lower average FCR of 12%, because industry and U.S. banks have experience with land-based projects and there are fewer unknowns.

The first financing scenario assumes that offshore project developers secure a DOE federal loan guarantee for project debt. If an offshore wind project developer receives a DOE loan guarantee, the developer would have a significantly lower cost of capital relative to all equity financing, and therefore, a lower estimated weighted average cost of capital (WACC). The loan guarantee offered by the U.S. federal government is assumed to cover approximately 64% of project capital costs, at a 6% interest rate, while the remaining 36% is assumed to be covered by equity contributions at an ROE of 30%. This combination of guaranteed debt and diminished equity investment results in a WACC of 13.3%, which translates to a 14% FCR.

The second scenario has an FCR of 22%. This assumes that the project would be 100% equity financed, with no loan guarantee, and an IRR of 20%. This raises the WACC for the project to 20% (as compared to 13.3% in the previous scenario). Despite the fact that ROE expectations greater than 20% have been reported to NREL, 20% is utilized here because a higher WACC is assumed to be cost prohibitive. 100% equity financing, with a 20% ROE, translates to an FCR of approximately 22% [20].

Table A-1. Offshore wind power project financing scenarios

Scenario 1: DOE Loan Guarantee		
	Rate of Return/Interest Rate	Capital %
Equity	30%	36%
Debt	6%	64%
WACC	13.3%	
Inflation	3%	
FCR	14%	

Scenario 2: 100% Equity Financing		
	Rate of Return/Interest Rate	Capital %
Equity	20%	100%
Debt	N/A	N/A
WACC	20%	
Inflation	3%	
FCR	22%	

Appendix B. Sample cost and scaling model output with LCOE calculation

From Input Page	
Machine Rating (kWs)	3600
Rotor Diameter (meters)	107
Hub Height (meters)	80

Offshore Shallow Water < 30 meters	
Cost in $	2008

Component	Componen t Costs $1000	Component Mass kgs
Rotor	821	79,436
Blades	536	47,711
Hub	124	20,853
Pitch mechanism & bearings	152	9,413
Spinner, Nose Cone	8	1,459
Drive train, nacelle	2,177	141,902
Low speed shaft	110	19,467
Bearings	67	3,037
Gearbox	596	26,153
Mechanical brake, HS coupling etc	7	716
Generator	293	12,335

Variable speed electronics	352	
Yaw drive & bearing	92	7,651
Main frame	311	67,212
Electrical connections	247	
Hydraulic, Cooling system	56	288
Nacelle cover	47	5,043
Control, Safety System, and Condition Monitoring	66	
Tower	805	284,353
Marinization (10.00% of Turbine and Tower System)	387	
TURBINE CAPITAL COST (TCC)	4,256	505,691
Monopile Foundation/Support Structure	1,636	
Turbine Transportation	552	
Port and Staging Equipment	109	
Turbine Installation	545	
Electrical Interface/Connect	1,576	
Permits, Engineering, Site Assessment	142	
Personal Access Equipment	64	
Scour Protection	300	
Surety Bond (Decommissioning - 3.0% of ICC)	275	
BALANCE OF STATION COST (BOS)	5,198	
Offshore Uncertainty	2,670	
Initial U.S. Project Risk	2,168	

Offshore Warranty Premium (15.00% of Turbine and Tower System)	580	
Initial capital cost (ICC)	14,873	505,691
Installed Cost per kW (cost in $) Turbine Capital per kW sans BOS & Warranty (cost in $)	4,131 1,182	140,470 140,470
Levelized Replacement Cost $ per year O&M $ per turbine/yr Bottom Lease Cost	65 264 15	
CAPACITY FACTOR Net ANNUAL ENERGY PRODUCTION Energy MWh (AEP)	39.33% 12403	
Fixed Charge Rate COE $/kWh	14.00% 0.1871	

Appendix C. PMDD generator calculations

Machine rating, rotor diameter, and tip speed were chosen and then used to calculate the turbines rated RPM and torque. As an average from the WindPACT Advanced Wind Turbine Drive Train Design Study [7] and other proprietary information, an air gap shear stress of 42 kN/m^2 was assumed in conjunction with the torque and corresponding generator diameter to calculate the generator length. Once the length and diameter of the generator was known, assuming an average constant generator density of 3,175 kg/m^3, or variable generator density derived from the same sources [7], the overall mass of the generator, including all support structures and housing, was calculated. The following formulas were used to complete Table 6 below.

$$L = \frac{T}{2\pi * \left(\frac{D}{2}\right)^2 * S_s}$$

$$S_g = \frac{60 * S_t}{\pi * D_b}$$

$$T = \frac{30 * R}{\pi * S_g}$$

$$M_c = D_c * (\pi * \left(\frac{D}{2}\right)^2 * L)$$

$$M_v = D_v * (\pi * \left(\frac{D}{2}\right)^2 * L)$$

$$D_v = 10169 * D^{-.75}$$

With:

L = Length of the Generator

T = Torque of the Generator

R = Turbine Rating

D = Diameter of the Generator

D_b = Blade Diameter

D_c = Constant Density

D_v = Variable Density

S_s = Generator Air Gap Shear Stress

S_g = Speed of the Generator

S_t = Tip Speed

M_c = Constant Density Generator Mass

M_v = Variable Density Generator Mass

Table C-1. PMDD generator calculations

Input					Output				
Rating (kW)	Blade Diameter (m)	Tip Speed (m/s)	PMDD Generator Diameter (m)	Shear Stress (kN/m^2)	PMDD Generator Length (m)	Speed (rpm)	Torque (kNm)	Constant Density Mass (kg)	Variable Density Mass (kg)
1000	55.0	75.0	3.5	42.0	0.45	26.04	367	13,817	17,379
2000	80.0	75.0	4.0	42.0	1.01	17.90	1067	40,196	45,751
3000	90.0	75.0	4.3	42.0	1.47	15.92	1800	67,831	73,139
4000	110.0	80.0	4.3	42.0	2.25	13.89	2750	103,631	111,740
5000	120.0	80.0	4.3	42.0	3.07	12.73	3750	141,315	152,372
6000	127.5	80.0	4.3	42.0	3.92	11.98	4781	180,176	194,275
7000	133.0	85.0	4.3	42.0	4.49	12.21	5476	206,375	222,523
8000	138.0	90.0	4.3	42.0	5.02	12.46	6133	231,128	249,213
9000	144.0	90.0	4.3	42.0	5.90	11.94	7200	271,324	292,555
10000	149.0	90.0	4.3	42.0	6.78	11.54	8278	311,939	336,348
11000	155.0	90.0	4.3	42.0	7.76	11.09	9472	356,950	384,881

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14. ABSTRACT *(Maximum 200 Words)*
This paper summarizes the work completed under the CRADA between NREL and American Superconductor (AMSC). The CRADA combined NREL and AMSC resources to benchmark high temperature superconducting direct drive (HTSDD) generator technology by integrating the technologies into a conceptual wind turbine design, and comparing the design to geared drive and permanent magnet direct drive (PMDD) wind turbine configurations. Analysis was accomplished by upgrading the NREL Wind Turbine Design Cost and Scaling Model to represent geared and PMDD turbines at machine ratings up to 10 MW and then comparing cost and mass figures of AMSC's HTSDD wind turbine designs to theoretical geared and PMDD turbine designs at 3.1, 6, and 10 MW sizes. Based on the cost and performance data supplied by AMSC, HTSDD technology has good potential to compete successfully as an alternative technology to PMDD and geared technology turbines in the multi megawatt classes. In addition, data suggests the economics of HTSDD turbines improve with increasing size, although several uncertainties remain for all machines in the 6 to 10 MW class.

15. SUBJECT TERMS
Superconducting; Direct Drive; Permanent Magnet; Design Cost and Scaling Model; Wind Turbine

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