SANDIA REPORT

SAND2018-9131
Unlimited Release
Printed August 2018

System Levelized Cost of Energy Analysis for Floating Offshore Vertical-Axis Wind Turbines

Brandon L. Ennis, D. Todd Griffith

Prepared by
Sandia National Laboratories
Albuquerque, New Mexico 87185 and Livermore, California 94550

Sandia National Laboratories is a multimission laboratory managed and operated by National Technology and Engineering Solutions of Sandia, LLC., a wholly owned subsidiary of Honeywell International, Inc., for the U.S. Department of Energy's National Nuclear Security Administration under contract DE-NA-0003525.

Approved for public release; further dissemination unlimited.



Issued by Sandia National Laboratories, operated for the United States Department of Energy by Sandia Corporation.

NOTICE: This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government, nor any agency thereof, nor any of their employees, nor any of their contractors, subcontractors, or their employees, make any warranty, express or implied, or assume any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represent that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government, any agency thereof, or any of their contractors or subcontractors. The views and opinions expressed herein do not necessarily state or reflect those of the United States Government, any agency thereof, or any of their contractors.

Printed in the United States of America. This report has been reproduced directly from the best available copy.

Available to DOE and DOE contractors from
U.S. Department of Energy
Office of Scientific and Technical Information
P.O. Box 62
Oak Ridge, TN 37831

Telephone: (865) 576-8401
Facsimile: (865) 576-5728
E-Mail: reports@adonis.osti.gov
Online ordering: http://www.osti.gov/bridge

Available to the public from
U.S. Department of Commerce
National Technical Information Service
5285 Port Royal Rd
Springfield, VA 22161

Telephone: (800) 553-6847
Facsimile: (703) 605-6900
E-Mail: orders@ntis.fedworld.gov
Online ordering: http://www.ntis.gov/help/ordermethods.asp?loc=7-4-0#online



SAND2018-9131
Unlimited Release
Printed August 2018

System Levelized Cost of Energy Analysis for Floating Offshore Vertical-Axis Wind Turbines

Brandon L. Ennis, D. Todd Griffith
Wind Energy Technologies Department
Sandia National Laboratories
P.O. Box 5800, MS1124
Albuquerque, NM 87185

Abstract

The levelized cost of energy for an offshore wind plant consisting of floating vertical-axis wind turbines is studied in this report. A 5 MW Darrieus vertical-axis wind turbine rotor is used as the study turbine as this architecture was determined to have the greatest ability to reduce the system cost. The rotor structural design was used with blade manufacturing cost model studies to estimate its cost. A two-bladed, carbon fiber rotor was selected in this analysis since the lower topside mass resulted in a reduction of the platform costs which exceeded the increased rotor cost. A direct-drive, medium efficiency drivetrain was designed which represents 25% of the costs and 45% of the mass of the combined rotor/drivetrain system. A direct-drive, permanent magnet generator drivetrain was selected due to the improved reliability of this type of system, while the cost was not significantly higher than for geared drivetrains. A platform was designed by first identifying the optimal architecture for the vertical-axis wind turbine at a water depth of 150 m. A survey was performed of floating platform types, and six characteristic designs were analyzed which span the range of stability mechanisms available to floating systems. A multi-cellular tension-leg platform was identified as the lowest cost platform which additionally provided some interesting performance benefits. The small motions of the tension-leg platform benefit the system energy capture while limiting inertial loads placed on the rotor's tower and blades. A final design was produced for the multi-cellular tension-leg platform considering operational fatigue, storm wind and wave conditions, and tow-out design cases. The driving design load was stability during tow-out while

ballasting the platform. System levelized cost of energy was calculated, including operational expenses and balance of system costs estimated for the wind plant. Opportunities for reduction in the component costs are predicted and used to make projections of the system levelized cost of energy for future developments. The opportunities and challenges for floating vertical-axis wind turbines are identified by the system design and levelized cost of energy analysis.

Acknowledgment

This work was funded by the Wind Energy Technologies Office within the US Department of Energy.

The authors would like to acknowledge contributions from others during this phase of the project. Giorgio Bacelli from Sandia National Laboratories developed a coupled aero-hydro-servo analysis tool that was used to perform the advanced controls studies for the rotor-platform system. Latha Sethuraman from the National Renewable Energy Laboratory performed the drivetrain design and cost estimates for the series of drivetrain types and efficiencies being considered as part of this study. Tyler Stehly from the National Renewable Energy Laboratory provided the Balance of System model that was used for portions of the cost analysis described within this report.

Document Revisions

Date	Version	Description
19-Aug-2018	1.00	Initial release.

Contents

Executive Summary **12**

Nomenclature **14**

Introduction **17**

1 Levelized cost of energy analysis **19**

2 Rotor Selection and Cost Analysis **21**

2.1 Rotor Definition for Design and Cost Analysis 21

2.2 Rotor Cost Analysis 21

2.2.1 Rotor Material Cost 22

2.2.2 Rotor Labor and Capital Equipment Cost 24

2.2.3 Rotor Structural and Material Optimization Opportunities 24

3 Drivetrain Cost Analysis **27**

3.1 VAWT Drivetrain Conceptual Description 27

3.2 VAWT Drivetrain Cost and Mass Estimation 29

4 Annual Energy Production **31**

4.1 Baseline Annual Energy Production Calculation 31

4.2 System Annual Energy Production Losses 33

4.3 Increased Energy Capture Opportunities 33

5 Platform Selection and Cost Analysis **37**

5.1 Platform Design Approach and Selection 37
5.2 Detailed Platform Design and Cost Estimation 44
5.3 Additional Supporting Sources for Selection of the Tension-Leg Platform 48

6 Additional Capital Expenditure Cost Analysis 51
6.1 Baseline Balance of System Cost Estimate 51
6.2 Baseline Financial Cost Estimate 53

7 Operations and Maintenance Costs 55
7.1 Baseline Operations and Maintenance Costs 55

8 Levelized cost of energy analysis 61
8.1 Baseline levelized cost of energy calculation 61
8.2 Levelized cost of energy analysis 62

9 Summary of Vertical-Axis Wind Turbine Benefits and Challenges 67

Conclusion 71

List of Figures

1.1 Offshore wind plant cost categories and sub-components. 20

2.1 Blade design model representations of the DC_2B_LCDT rotor. 22

3.1 A general conceptual layout of major drivetrain components at the base of VAWT turbine [2]. 28

4.1 Sandia 5 MW VAWT power curve. 31

4.2 Sandia 5 MW VAWT power curve with advanced controls. 34

4.3 Performance variation using optimal controls at an 18 m/s wind speed. 35

4.4 Platform overturning moment contribution using optimal controls at an 18 m/s wind speed. 36

5.1 Platform architecture and stability mechanisms for the six platforms considered in the platform design studies. 38

5.2 Platform estimated total cost comparison from Phase 1 design study [2]. 39

5.3 Platform estimated cost component comparison from Phase 1 design study [2]. . . . 41

5.4 Platform performance comparison of the Phase 1 concepts [2]. 43

5.5 Patran model of the final McTLP hull [2]. 45

5.6 The sensitivity of levelized cost of energy for offshore sites to platform architecture and water depth [15]. 49

5.7 Technology readiness level for different floating platform architectures [16]. 50

7.1 Drivetrain-related operations and maintenance costs considering different drivetrain types [20]. 56

7.2 Failure rate and category for turbine sub-systems [19]. 57

7.3 Wind turbine availability for different drivetrain types and distance from shore [20]. 58

7.4 Wind plant distribution of combined operations and maintenance costs [23]. 59

7.5 Description of operations and maintenance transportation costs by vessel type [23]. 60

8.1 Levelized cost of energy distribution for the projected cases (diameter is proportional to LCOE). 66

List of Tables

1 Wind plant site of study specifications. 18

2.1 Rotor topside properties for the Sandia 5 MW VAWT. 22

2.2 Rotor material cost assumptions. 23

2.3 Rotor ptojected cost reduction pathway. 25

3.1 Mass and cost estimates for major drivetrain components. 29

4.1 Aerodynamic annual energy production sensitivity with wind distribution. 32

4.2 Electrical annual energy production sensitivity with generator efficiency. 32

5.1 Hull and mooring properties and resulting cost estimates for the Phase 1 platforms [2]. 42

5.2 Maximum platform motions from Phase 1 designs. 44

5.3 Phase 2 platform design iteration summary [2]. 46

5.4 Platform cost estimates produced by SES and the most-likely value. 48

5.5 Platform cost estimate projections. 48

6.1 Electrical infrastructure costs for wind plant with 100 floating VAWTs. 52

6.2 Baseline wind plant balance of system costs and data source. 52

6.3 Baseline wind plant financial costs and data source. 53

7.1 Operations and maintenance downtime costs ($av. = 94.2\%$). 58

8.1 Summary of LCOE cost input sources. 62

8.2 Baseline LCOE inputs and calculation (FCR = 10.3%). 63

8.3 LCOE study scenarios and design improvements. 65

Executive Summary

A detailed study of vertical-axis wind turbines at deep-water offshore sites requiring floating platforms is summarized in this report. The objectives of this study are to perform a levelized cost of energy analysis using the most trusted references available, to assess the technical and economic feasibility, and establish a baseline case as a reference for future studies. The analysis is performed for a representative 500 MW wind plant off the northeast coast of the United States. A 5 MW vertical-axis wind turbine was designed for this study using the Darrieus rotor architecture, which was identified as having the greatest ability to reduce the system levelized cost of energy. The levelized cost of energy was calculated with a range from $213/MWh to $110/MWh for scenarios which capture anticipated technical advancement and design optimization for this system. The most significant contributors to the reductions in cost for this system were platform optimization, reductions in the finance rate equivalent to that of land-based installations, and advancements resulting from rotor structural and material optimizations.

A significant body of work is represented in the platform selection and design within this report. A multi-cellular tension-leg platform was identified as the optimal platform through comparison with five other platforms which span the range of stability mechanisms available to floating systems. This platform was 10% less expensive than the closest alternatives, the classic spar design and a 4-column semi-submersible platform, but also has interesting advantages resulting from its small platform motions and compact mooring footprint. The driving load case for this platform was tow-out stability during ballasting, which means that a horizontal-axis wind turbine with over double the roll/pitch mass moments of inertia and center of gravity would require a more massive and costly tension-leg platform. However, a detailed analysis of the optimum platform for a horizontal-axis wind turbine should be performed to compare directly. The platform is the largest single contributor to the levelized cost of energy, representing around 40% of the total. The vertical-axis wind turbine rotor and drivetrain in this study represents around 20% of the system levelized cost of energy, compared to approximately 65% for land-based installations. This will result in developments in wind turbine rotors and other components that are more costly which would not be considered for land-based systems but which help to reduce platform costs or offer other benefits.

Advanced controls were developed in this analysis to exploit the vertical-axis wind turbines periodic loading, resulting in a 16% increase in energy capture over constant rotational speed control while maintaining the ultimate platform overturning moment. The controller optimized towards a bang-bang controller which potentially enables a different electrical conversion mechanism than traditional electrical generators. The removal of active control systems in addition to the platform-level placement of drivetrain and electrical components results in a 25% reduction in the combined operations and maintenance costs over a horizontal-axis wind turbine with pitch and yaw systems. The operations and maintenance costs are essentially fixed per turbine, meaning that significant

reductions arent expected with a maturing industry, and that they would likely be a smaller percentage of the levelized cost of energy for larger turbines (assuming the same reliability). In this study, the combined operations and maintenance cost for the future projection represents 26% of the total levelized cost of energy making this cost component nearly equivalent to the turbine and drivetrain capital expenditures. Improvements in turbine reliability and operations and maintenance strategies will be an increasingly important area of study as the industry matures.

The 5 MW turbine capacity was selected at the project onset to compare with existing 5 MW horizontal-axis wind turbine reference models and reference studies. This is a small capacity relative to what is being designed currently for offshore applications, and future offshore studies should be for 10-20 MW wind turbines. This scaling will favor a reduced levelized cost of energy since platform costs do not scale directly with turbine capacity. The higher capacity will also favor vertical-axis wind turbines where the massive drivetrain remains at platform level, as opposed to being increasingly further from the mean water level as for larger horizontal-axis wind turbines with higher hub-heights required for blade ground clearance. Scaling sensitivity studies should be performed in future work looking at platform, vertical-axis and horizontal-axis wind turbine costs and feasibility.

The levelized cost of energy values reported in this analysis should not be directly compared to other studies using different cost data. There is likely a level of conservatism overestimating the platform costs due to the difficulty in directly translating the cost data used from the offshore oil and gas industry to wind turbine platforms, which are much simpler platforms without human occupancy. It is recommended that a follow-up study be conducted to directly compare the levelized cost of energy for vertical-axis and horizontal-axis wind turbine systems with optimal platforms using a common set of cost and technical assumptions to better highlight the potential to reduce costs in floating offshore systems.

Nomenclature

A&I Assembly and installation

AEP Annual energy production

av. Wind turbine availability

BOS Balance of system

CACTUS Code for Axial and Cross-flow TUrbine Simulation

CapEx Capital expenditures

CG Center of gravity

CTV Crew transfer vessel

DD Direct drive

DFIG Doubly-fed induction generator

DOE Department of Energy

FCR Fixed charge rate

HAWT Horizontal-axis wind turbine

LCOE Levelized cost of energy

McTLP Multi-cellular tension-leg platform

MOI Moment of inertia

MWL Mean water level

NREL National Renewable Energy Laboratory

NuMAD Numerical Manufacturing and Design tool

O&M Operations and maintenance

OAV Offshore access vessel

OEM Original equipment manufacturer

OpEx Operational expenditures

OWENS Offshore Wind Energy Simulation analysis tool

PMG Permanent magnet generator

SES Stress Engineering Services

SNL Sandia National Laboratories

TLP Tension-leg platform

TRL Technology readiness level

VAWT Vertical-axis wind turbine

This page intentionally left blank.

Introduction

The offshore vertical-axis wind turbine project led by Sandia was performed to assess whether the trends and future development in the wind energy industry would be aided by considering this deviation from the traditional horizontal-axis wind turbines which dominate land-based installations. Both the continual move towards higher capacity machines and the anticipated development of deep-water, offshore sites which require floating platforms provide advantages for vertical-axis wind turbines, where platform costs represent the main single contributor to the total system costs. The goal of this project has been to produce better understanding of the technical and economic feasibility of the floating vertical-axis wind turbine technology solution for offshore wind. Floating vertical-axis wind turbines have many inherent advantages that show promise for reducing costs over floating wind systems using conventional horizontal-axis wind turbines. However, the technical and economic feasibility had been largely unexplored in a comprehensive manner, and it has been the purpose of this project to determine the challenges and opportunities for vertical-axis wind turbines at offshore sites where floating systems are required. The project was conducted in two phases, which are summarized by two reports. The first phase was conducting design studies using a variety of rotor architectures and platform types to assess the feasibility of the technology at this scale. The design studies, methodologies, and findings are described in the full report [1]. Phase two of the project was performed to gain more confidence in the system cost analysis, with a focus on the platform design and cost estimate. The platform selection and design represents a large body of work from this study, which was performed in collaboration with a consultant from the oil and gas industry. The resulting system levelized cost of energy was then studied using the highest fidelity of sources available for each of the capital and operational expenses for the offshore wind plant with floating vertical-axis wind turbines.

Focus of previous vertical-axis wind turbine design studies

It is widely believed that a new and transformative technology solution is needed to reach significant levels of wind energy development at deep-water offshore sites in the United States. The vast resource available at these deep-water sites in the US further motivates this study.

The basis for the current cost analysis is the previous system design studies of the major components of a floating vertical-axis wind turbine (VAWT); rotor, drivetrain, and platform and mooring. The optimal architecture for a floating VAWT system was an open question at the start of this research program, and the previous studies investigated a wide range of configurations for the major components focused on better understanding the design space and minimizing the levelized cost of energy (LCOE). A range of VAWT rotor configurations were evaluated through aerodynamic and structural design. This study confirmed the high aerodynamic performance of large-scale VAWTs,

as well as their trends based on operational conditions and design decisions. The platform is a major cost driver for floating offshore wind energy, and these studies provided broad insights into the requirements for floating VAWTs. The studies also showed that floating platforms were smaller and less costly for the floating VAWT versus a floating horizontal-axis wind turbine (HAWT), mainly due to lower center of gravity and mass moments of inertia. These initial platform sizing studies focused only on spar and semi-submersible types. Through a better understanding of the design space, it was possible to determine a preferred system configuration by estimating the system LCOE.

Focus of current levelized cost of energy analysis

The focus of this report is a thorough levelized cost of energy analysis for a floating offshore vertical-axis wind turbine system using the most trusted sources available. This analysis provides realistic values for system LCOE including cost projections which highlight key areas of study for further cost reduction. The platform and mooring design was a focus of this analysis to identify the optimal solution for a floating VAWT by leveraging industrial experience to produce accurate platform designs and cost estimates. Considering a representative site off the coast of the US northeast with a 150 m water depth, Table 1, a wide range of floating system types were considered. The studied platform types include semi-submersibles (3 and 4-column versions), spars (classical and advanced spars), a ring pontoon barge, and a multi-cellular tension leg platform. A detailed study of floating systems was performed [2] that provides qualitative and quantitative comparisons of the pros and cons of different platform types, which should provide guidance for future studies in choosing platform characteristics. The component costs and operational costs are estimated for the study VAWT, including the cost of the final platform which was designed for the VAWT topside properties. The main outcomes of this study are the platform design, and a comprehensive LCOE estimation including near-, mid-, and longer-term projections based on opportunities identified in this analysis.

Table 1. Wind plant site of study specifications.

Parameter	Value	Units
Water depth	150	m
Distance to shore	25	km
Number of turbines	100	#
Turbine rating	5	MW

Chapter 1

Levelized cost of energy analysis

This section presents the levelized cost of energy analysis methodology used in this report for offshore vertical-axis wind turbine systems. A standard LCOE approach is used which is applied for an offshore wind plant. This approach categorizes costs as capital expenditures or operational expenditures, as illustrated in Figure 1.1. Capital expenditures are amortized annually using a fixed charge rate which accounts for several financial factors for the initial capital cost loan, such as the level of risk in the project. Capital expenditures are further categorized as turbine costs, balance of system costs, and financial costs. The capital expenditures represent all the costs required to develop an offshore wind plant to an operational stage, including site and project development, turbine and platform acquisition and fabrication, wind plant and electrical infrastructure installation, in addition to the financial costs associated with the purchases and installation. Operational expenditures are those which are incurred each year. Operations and maintenance costs are the main contributor to this source, but also includes leasing costs for the site. The items listed within the sub-categories of the capital and operational expenditures in Figure 1.1 are all estimated as part of this report and utilized to perform an LCOE analysis for floating offshore vertical-axis wind turbines.

The LCOE is calculated in this report according to the equation:

$$LCOE = \frac{(CapEx * FCR) + OpEx}{AEP_{net}} \tag{1.1}$$

$CapEx$ represents the initial capital expenditures, FCR is the fixed charge rate, $OpEx$ is the operational expenditures, and AEP_{net} is the annual energy production that reaches the electrical grid after wake and downtime losses are included. Using the four sub-categories of costs described in Figure 1.1 the equation becomes:

$$LCOE = \frac{(Turb + BOS + Fin) * FCR + O\&M}{AEP_{net}} \tag{1.2}$$

This report goes through the cost components and energy production variables required for calculating LCOE. Design improvements to the various cost components are estimated throughout each section. The level of detail included for the various cost sources is meant to be exhaustive,

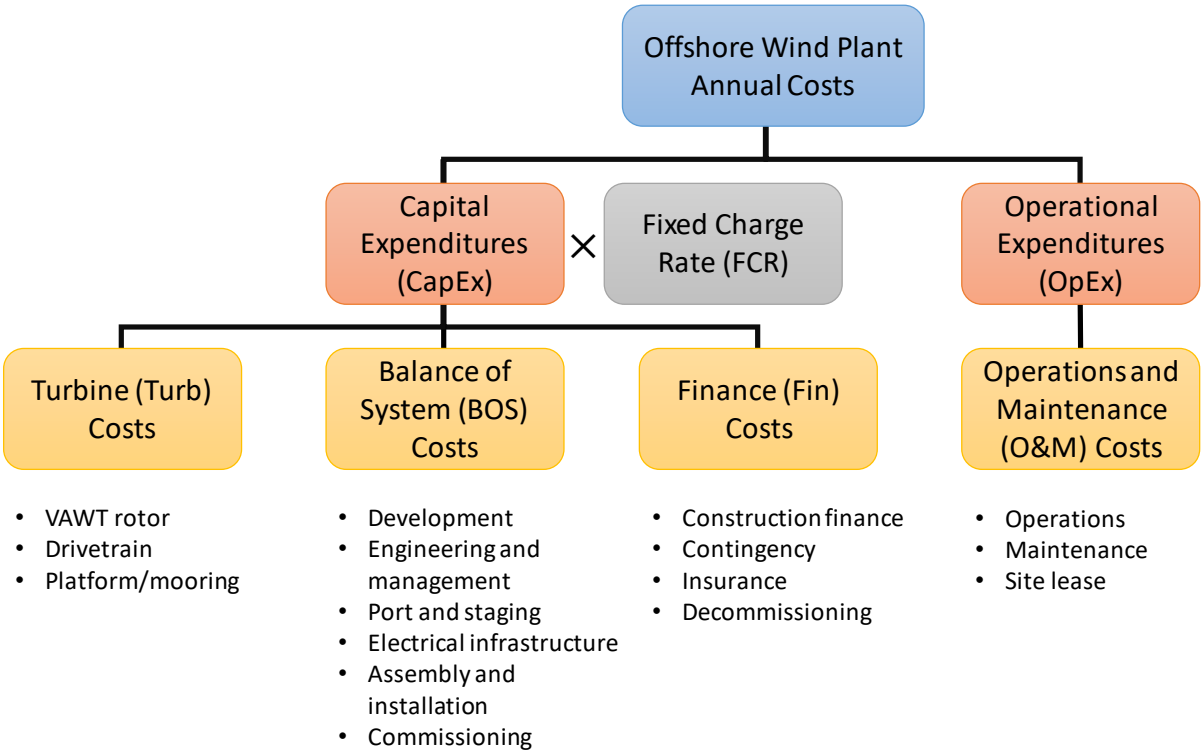


Figure 1.1. Offshore wind plant cost categories and sub-components.

but the accuracy is governed by the availability of representative cost data. A significant level of effort was placed on accurately estimating the most substantial cost components in this report. The platform, mooring, and installation design and cost estimates were produced in partnership with a design consultant from the oil and gas industry. Rotor costs were estimated from a detailed structural model of a Sandia designed VAWT from a previous study with a blade manufacturing cost model developed in partnership with a blade manufacturer. Drivetrain, balance of system, and financial costs were estimated from detailed models which were developed using data from existing offshore wind plants. Operations and maintenance costs and downtime losses are estimated from a thorough literature review using recent publications from existing offshore wind plants. The detailed component cost estimation is given in the following sections in this report, describing the modeling approach, sources of data, and assumptions. These cost estimates are then utilized in Section 8.2 for calculation of the LCOE for five study scenarios described by design improvements and projections within the component sections.

Chapter 2

Rotor Selection and Cost Analysis

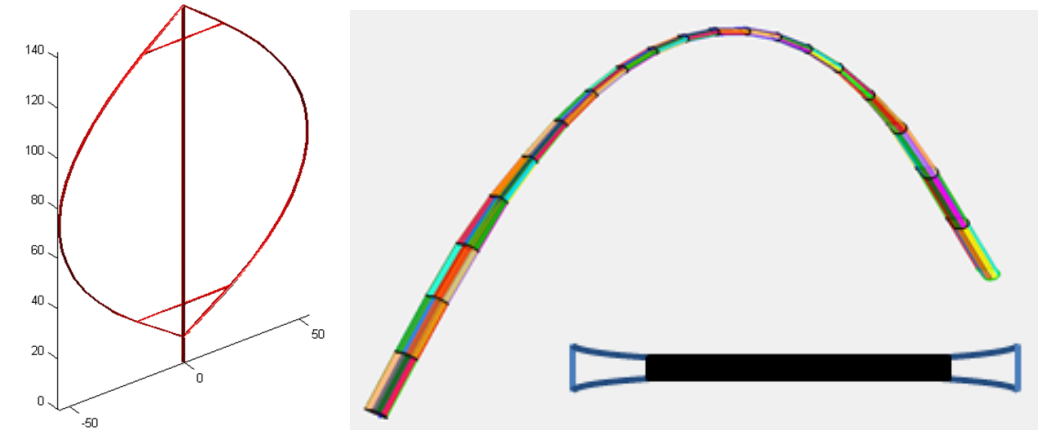
2.1 Rotor Definition for Design and Cost Analysis

The optimal VAWT blade architecture was analyzed during the previous design studies performed by Sandia, identified as the system with the most potential to reduce blade cost for the same blade radius and rotor swept area [1]. The design studies analyzed two primary design types, the classic Darrieus VAWT along with V-VAWT designs. The V-VAWT designs were defined using a power law with exponents producing blade profiles ranging from a "V" shape to more of a "U" shape. For the present study, a Darrieus VAWT design was selected due to the designs ability to greatly reduce blade strain in operation. The Darrieus design carries the aerodynamic forces mostly axially, as opposed to needing to support bending moments like for the V-VAWT designs. Bending moments are the largest contributor to blade strain, and therefore to blade material requirements. For this study, a Darrieus 2-bladed design with an increasing chord taper towards the tower supports was selected for the LCOE analysis. The structural design from the previous studies using all carbon-fiber material was utilized in this analysis. This design was selected due to the significant reduction in rotor mass and the relative system cost contributions from roll/pitch moment of inertia compared with the rotor cost impact. A hybrid design would likely be most optimal from a system cost perspective, with glass fiber reinforced polymer material being used for the shell material and as part of the tower structure. An optimized material usage study was however outside of the scope of the current analysis.

The selected DC_2B_LCDT rotor is depicted as analyzed using the Sandia VAWT design tools in Figure 2.1, illustrating the double taper blade design. Characteristic of a VAWT, compared to a HAWT, the rotor consists of the blades, tower, and struts which all rotate during operation. Properties of the DC_2B_LCDT rotor topside are provided in Table 2.1, including general blade dimensions.

2.2 Rotor Cost Analysis

The cost of the rotor includes costs from three major cost components: materials, labor, and tooling (such as molds). Costs are estimated based on cost factors referencing studies for large wind turbine blades. The Department of Energy has funded several wind turbine blade manufacturing



(a) OWENS aeroelastic model **(b)** NuMAD structural model

Figure 2.1. Blade design model representations of the DC_2B_LCDT rotor.

Table 2.1. Rotor topside properties for the Sandia 5 MW VAWT.

	DC_2B_LCDT
Turbine type	Darrieus
Number of blades	2
Material system	carbon fiber
Taper at blade root	double taper
Blade length	178 m
Equatorial chord	3 m
Root chord	6 m
Tower diameter	6 m
Equatorial rotor radius	54 m
Tower extension	10 m
Rotor height (inc. extension)	142 m
Rotor mass	220,800 kg

studies over the past 10 years [3, 4], and these studies are the primary references for the rotor cost estimate.

2.2.1 Rotor Material Cost

In the previous VAWT design studies, the determination of rotor material cost was performed assuming that the entire rotor mass was comprised of the fiber reinforced polymer, glass or carbon. This approach is consistent with the accuracy of the level of the design itself, apart from a final

design with manufacturing drawings. The usage of panel core material, which represents a small percentage of the blade mass, would produce a slightly lower rotor cost for the carbon fiber rotor design. The material cost of the rotor, consisting of the blades, tower, and struts, is computed using representative composite material costs per weight listed in Table 2.2. Composite material costs are defined using the two fiber materials, and considering various methods for resin transfer for the carbon fiber composites. In the previous design studies, it was assumed that the material used was 100% carbon fiber prepreg. Carbon fiber has shown sensitivity to manufacturing defects, particularly when the traditional resin infusion manufacturing methods have been used in the past. This consideration motivated the decision in the previous study to utilize all carbon fiber prepreg in the cost estimate, as a conservative approach. As a result, the Darrieus VAWT designs analyzed during the prior design studies had material costs ranging from $6.3MM to $9.9MM using only prepreg carbon fiber, compared with costs of $3.2MM to $7.6MM for the glass composite designs. The differences were a result of the lower cost of glass fiber, but where material requirements resulted in more massive rotors. The range of costs represents the various rotor configurations analyzed in the studies, such as number of blades, rotor speed limit, and blade chord tapering scheme.

Table 2.2. Rotor material cost assumptions.

Material system	Fiber Volume	Unit cost [$/kg]	Unit cost [$/lb]
Glass fiber composite (resin infusion)	0.55	4.40	2.00
Carbon fiber composite (resin infusion)	0.55	19.38	8.81
Carbon fiber composite (pultrusion)	0.7	25.40	11.55
Carbon fiber composite (prepreg)	0.6	28.60	13.00

The DC_2B_LCDT rotor being analyzed in the present study, using all prepreg carbon fiber material with the stated assumptions has an associated material cost of $6.3MM. This is nearly double that of the least expensive all glass-fiber rotor, but the decreased rotor topside mass and roll/pitch moment of inertia of the expensive carbon fiber rotor is considered to enable a more substantial cost reduction in the platform, resulting in a lower system cost.

Wind turbine manufacturers using carbon fiber in their blade designs have moved away from resin infusion and pre-impregnated (prepreg) carbon fiber materials in favor of intermediate composite pultruded forms for spar caps. Pultrusions ensure the highest quality of carbon fiber composite by limiting manufacturing defects and have the added benefit of enabling higher fiber volume fractions. Pultruded carbon fiber can have fiber volume fractions up to 70%, compared with around 55-60% for resin infusion or prepreg manufacturing methods. This increase in fiber volume fraction results in improved composite material properties per mass, or a reduction in around 15% of the material need (for structural members such as the spar cap).

2.2.2 Rotor Labor and Capital Equipment Cost

Two approaches were considered to estimate the labor costs in producing the VAWT rotor. These include (1) applying cost distributions for similar large blades by scaling the total costs based on the materials cost and (2) a "bottoms up" estimate based on the detailed material layup, composite schedule, and fabrication process for the rotor using manufacturing cost models for blades. For this study, the former approach was determined to be most appropriate for this stage in the feasibility assessment of a floating VAWT system.

Griffith and Johanns previously developed a manufacturing cost model for wind turbine blades [3], which was developed to estimate costs for large blades including materials, labor, and capital equipment (i.e tooling costs). This model includes a detailed manufacturing process that can account for design changes including scaling for blade length and different material choices. The model was also validated against several commercial blades. Additional information can be found in Reference [4]. Utilizing this manufacturing model to estimate the cost of a much longer, curved blade than those used to produce the cost model calls into question the accuracy of the model, however, these differences mostly only affect the capital equipment costs which are a relatively small fraction of the total cost. This blade manufacturing cost model was used to produce cost estimates for 100 m blades (for horizontal-axis wind turbines) including all-glass material blades as well as blades with carbon spar caps [3]. For a 100 m carbon spar blade the cost breakdown was 75% for material costs, 12% for labor costs, and 13% for capital equipment. Based on this distribution of costs, \$6.3MM of material costs equate to \$1.0MM for labor costs and \$1.1MM for capital equipment costs. The total rotor cost is then estimated to be \$8.4MM for the baseline carbon Darrieus VAWT having 2 blades rated at 5 MW.

2.2.3 Rotor Structural and Material Optimization Opportunities

This section explores likely cost scenarios that would result from rotor material optimization. Realistic assumptions will be made which represent decisions to remove excess strength from the previously designed rotor which consisted completely of carbon fiber prepreg material. The present cost estimation represents the industry's move towards intermediate carbon fiber pultruded forms which yield higher fiber volume fractions and more consistent material properties, as shown in Table 2.3. Exchanging some of the more structurally important prepreg material for pultruded carbon fiber will both reduce the weight and the cost of the rotor. The assumptions to produce this revised cost estimate are that the structural material where pultruded sheets can be used represents 70% of the tower weight and 20% of the blade weight, or 55% of the total rotor mass. Since the pultrusions have a higher fiber volume fraction than the prepreg material, it is assumed that the amount of carbon fiber needed is reduced by the fiber volume fraction ratio between the two forms, representing a 14.3% reduction in material for these portions of the blade. For the remaining 45% of the rotor, it is assumed that half is important structurally and half is not (such as the blade aerodynamic shell). The structural half will use prepreg carbon fiber, while the other half will use glass fiber. The glass fiber is approximately 25% heavier for the same thickness of material, so this portion of the blade will consist of 125% of its original mass at the cost of glass fiber. Utilizing these approximations

results in a rotor material cost of $4.2MM for the optimized rotor consisting mostly of carbon fiber pultrusions, then infused glass fiber, then carbon fiber prepreg. This is a reduction in material cost from the $6.3MM all carbon fiber prepreg rotor from the earlier studies. Since the blade shape is the same, the remaining capital costs and labor costs are assumed to be constant at the previous amount of $2.1MM. The total blade cost for this mid-term, material optimized rotor is then $6.34MM.

Advancements in carbon fiber development for vehicle and wind energy applications has shown promise in providing a low-cost alternative to the aerospace grade carbon fiber that is widely available today. These low-cost carbon fiber materials sacrifice tensile strength properties while producing similar compressive properties at nearly half the cost of commercially available carbon fiber. These developments are included in the long-term projected cost estimates used in this analysis. Assuming the same material distribution as in the mid-term optimization while using the estimated price for low-cost carbon fiber materials in development today produces a material cost of $3.04MM, with a total long-term, advanced materials rotor cost of $5.15MM.

Table 2.3. Rotor ptojected cost reduction pathway.

Rotor system	Description	Rotor cost [MM USD]
Baseline DC_2B_LCDT [1]	100% carbon fiber prepreg	8.42
Mid-term development	Material optimized rotor	6.34
Long-term development	Advanced carbon fiber material	5.15

This page intentionally left blank.

Chapter 3

Drivetrain Cost Analysis

This section presents the drivetrain modeling results for the DC_2B_LCDT_VAWT rotor configuration. A description of the conceptual layout of the major drivetrain components is presented, followed by estimates for the mass and costs of these components.

3.1 VAWT Drivetrain Conceptual Description

One inherent advantage of a VAWT versus a HAWT is that the drivetrain is located at the base of the turbine near the water line. This results in multiple benefits including lower platform roll/pitch moment of inertia (MOI) and center of gravity (CG) for the rotor topside assembly in addition to providing easier access to drivetrain components. The turbine roll/pitch MOI is a major driver for platform costs which is the largest single contributor to the system LCOE. Easier access to drivetrain components by personnel using smaller equipment favors lower operations and maintenance costs, particularly when considering the reduced weather restrictions for small vessels and with maintenance occurring at a lower height where wind speed restrictions will be reduced. A current drivetrain disadvantage came from the selected rotor which operates at a lower tip speed ratio than for modern HAWTs. This low-speed, high-torque rotor requires a more massive drivetrain for the selected VAWT, although it has a higher solidity rotor with a more efficient structural design which reduces top-side rotor weight. This was a design trade-off which was optimized using first principle design studies, but could be further investigated using the final platform.

To estimate the drivetrain system mass and cost, a preliminary design of the VAWT drivetrain major component layout was generated as illustrated in Figure 3.1. Although conceptual and not to scale, this spatial layout of equipment is useful to better understand the required components and their general layout. For this study, a direct-drive system has been selected for mechanical simplicity and the associated reliability benefits, as supported in the Operations and Maintenance section. Furthermore, initial screening studies indicated that the costs of geared and direct-drive systems were similar.

While the drivetrain components included in this design are not exhaustive, the design includes the most significant contributors to cost and mass at an accuracy level that is appropriate for this stage of design study. As depicted in Figure 3.1, the components included in the drivetrain cost and mass estimates are:

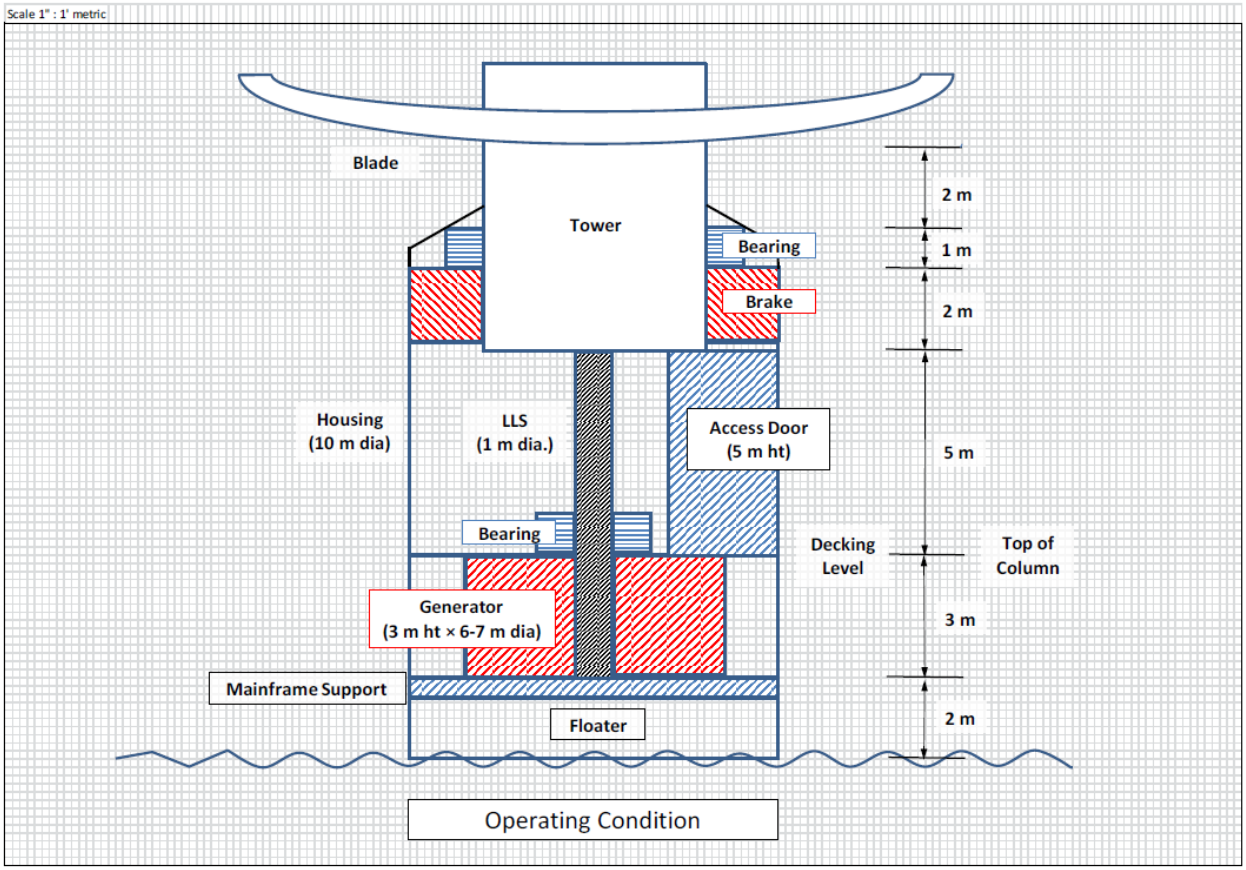


Figure 3.1. A general conceptual layout of major drivetrain components at the base of VAWT turbine [2].

- Direct-drive generator
- Main bearings
- Low-speed shaft
- Mainframe support
- Mechanical brakes

Owing to the choice of a direct-drive configuration, the common drivetrain components of gearbox, high-speed shaft, and coupling are not required in the analysis. Additionally, it is noteworthy that the VAWT configuration eliminates several other drivetrain sub-system components typically found in a HAWT configuration. These removed systems include the pitch mechanism and pitch bearings, yaw drive and yaw bearing, and the nacelle bedframe which can be quite massive.

3.2 VAWT Drivetrain Cost and Mass Estimation

The VAWT drivetrain mass estimate is needed to specify the turbine topside mass properties and enable accurate platform and mooring design. In addition to drivetrain mass estimates, cost estimates are produced as part of this study to be included in the system LCOE analysis. Table 3.1 lists the mass and cost estimates for each of the major VAWT drivetrain components in addition to cost estimates for power electronics related to the turbine control.

Table 3.1. Mass and cost estimates for major drivetrain components.

Drivetrain Component	Mass [tons]	Cost [USD]
Direct-drive generator	318	$1,504,821
Mainframe support[1]	62	$198,400
Low-speed shaft[1]	37	$59,200
Main bearings[1]	112	$55,000
Mechanical brake	5	$95,000
Variable speed electronics	–	$639,000
Electrical connections	–	$324,000
Hydraulics and cooling	–	$97,000
Total drivetrain	434	$2,972,421
Topside CG	18.2 m	

[1]The mass estimates are preliminary and were obtained by adjusting estimates from [5] to better reflect the VAWT design.

The drivetrain component estimates were produced using the National Renewable Energy Laboratory's (NREL) GenratorSE tool [6] for generator sizing and using a cost and scaling model for the additional components [5], with necessary assumptions for the VAWT system. A design study looking at the trade-off of generator type and efficiency versus cost and mass was performed to select the final design with support from drivetrain experts at NREL. The more efficient designs directly divide the LCOE equation with increased energy capture, but become increasingly heavy as they move towards highly efficient designs. Several options were explored, and the 95% efficiency generator was selected for its seemingly optimal balance of efficiency and mass for the floating VAWT system. To achieve this efficiency (at the given torque rating) required a 318 ton generator. For the combined drivetrain system, this results in an estimated total drivetrain mass of 434 tons, which is located at approximately 3.5 m above the mean water level (MWL) as depicted in Figure 3.1.

It is important to note that since the VAWT generator CG is slightly above the MWL that an increase in its mass would result in a minor increase of topside MOI while decreasing the topside CG, which are two important parameters in the platform design. For a HAWT, an increase in generator mass would more substantially increase both the topside MOI and CG. This difference emphasizes the inherent advantage of the VAWT that allows the generator to be optimized with

respect to efficiency while the added generator mass is of minor consequence or possibly even beneficial depending on the platform type. The VAWT offers additional interesting benefits where the generator can be located beneath the MWL which means its mass reduces both the topside MOI and CG [7].

In estimating the cost and mass of the remaining major drivetrain components, the following assumptions were made:

- The mainframe support for the VAWT would require a more compact bedplate than a HAWT since the structural material is largely, or even wholly, accounted for in the platform design. As a conservative estimate of this assumption, the mainframe mass was assumed to be 50% of the up-scaled valued estimated from [5].
- The low-speed shaft mass was estimated by up-scaling based on the operating torque of the VAWT rotor [5].
- Main bearing cost and mass were estimated again using the scaling data provided by Fingersh with a preliminary layout to distribute the rotor moment as shown in Figure 3.1. The bearing estimate likely has the greatest associated uncertainty where VAWT bearings carry the rotor thrust transversely (due to the produced bending moment), compared to axially loading from thrust with a HAWT. This uncertainty is not thought to be very significant as the scaled bearings still represent only a small contribution to overall drivetrain mass and cost.
- Mechanical brakes were also based on up-scaling with an additional factor applied to provide larger brakes. This was assumed because HAWTs can regulate rotational speed through the pitch system which is not included in the current VAWT design which is purely stall-regulated and not pitch-regulated.
- For the remaining components of variable speed electronics, electrical connections, and hydraulics and cooling, their impact of drivetrain cost was included while mass was neglected, based on the available data.

The generator cost was based on a representative design and the material costs used for the design with an empirical factor applied to estimate the so-called "factory gate" price. A radial flux interior rotor permanent magnet generator configuration was designed using the VAWT torque and rpm specifications. The generator active and structural materials were approximated using GeneratorSE [6], which is a set of analytical tools for dimensioning variable speed wind turbine generators. GeneratorSE provided estimates for the mass and costs for the various materials used in the design. Then, based on the estimated materials cost for the design, the total "factory gate" generator cost was estimated using a factor developed through regression from Reference [8] which was applied to account for fabrication costs. Comparable results were reported for permanent magnet synchronous generators [9]. Scaling cost data were used for the bearings and brakes, with the above assumptions. The mainframe and low-speed shaft costs were estimated using a market price of \$0.80/kg for steel [10] and estimated factors for the manufacturing labor costs. The mainframe support materials were assumed to be 25% of the total cost with 75% for manufacturing. For the low-speed shaft the assumption was 50% materials and 50% manufacturing costs. Using the stated references and assumptions resulted in estimates for the total drivetrain mass and cost of 434 tons and \$2.97MM, as detailed in Table 3.1.

Chapter 4

Annual Energy Production

4.1 Baseline Annual Energy Production Calculation

The Sandia DC_2B_LCDT vertical-axis wind turbine is used to calculate the baseline annual energy production (AEP) for the site of study, with power curve shown in Figure 4.1. For the baseline AEP calculation a cut-out wind speed of 25 m/s is used to limit the increasing loads with wind speed as is present with a fixed geometry VAWT. The power performance of the DC_2B_LCDT was derived from simulations in the turbine simulation tool CACTUS [11]. The simulations were performed using steady inflow without velocity shear.

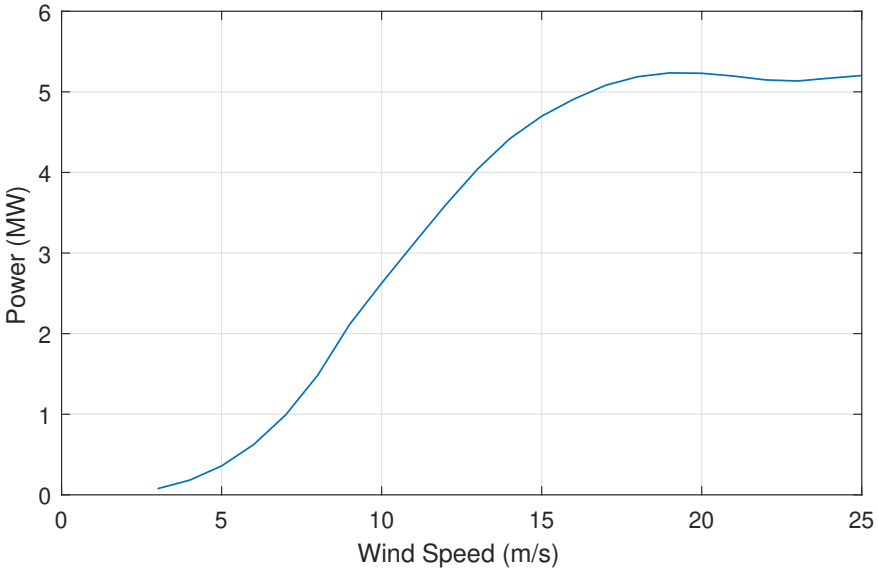


Figure 4.1. Sandia 5 MW VAWT power curve.

The turbine power curve is used in conjunction with a site's wind speed distribution in the first approximation for AEP. A meteorological buoy nearby and representative of the site has been used as an estimate for the average wind speed, which has a three-year average of 6.55 m/s at 10 m above MWL. This value is translated to a rotor center height of 86 m above MWL using a power law approximation of the velocity profile. A shear exponent of 0.2 is used for the velocity profile

as defined in the IEC 61400-1 wind turbine design requirements standard [12]. This velocity profile produces a rotor center mean value for the wind speed of 10.1 m/s. The standard probability distribution used to describe atmospheric wind conditions is the two parameter Weibull distribution. Given limited wind speed information it is common to assume a Rayleigh distribution, which is done here. The Rayleigh distribution is a Weibull distribution with shape factor set to 2. The shape factor describing distributions in wind speed is typically between the values of 1.5-3, and its influence on the AEP is shown in Table 4.1 along with the baseline aerodynamic AEP calculated using a shape factor of 2, with a value of 21,145 MWh.

Table 4.1. Aerodynamic annual energy production sensitivity with wind distribution.

Weibull shape factor	Aerodynamic AEP [MWh]	Percent deviation
1.5	18,628	-11.9%
2	21,145	0.0%
2.5	22,154	4.8%
3	22,525	6.5%

The AEP values shown in Table 4.1 do not yet account for any of the losses that reduce this value to the ultimate electrical AEP. The first loss is that which arises from the conversion to electrical power as performed by the turbine's generator (i.e. the generator efficiency). The generator losses are assumed to be constant with rotational speed and therefore are represented by a rectangular probability distribution with wind speed which means the efficiency multiplies the aerodynamic AEP to result in the electrical energy production. The DC_2B_LCDT reaches the design rotational speed of 7.2 rpm at 9 m/s with only 13% of the total energy produced for the baseline case in this lower rotational speed region, making the rectangular distribution treatment of the generator losses reasonable.

Table 4.2 shows the results of AEP accounting for generator losses. The baseline design value of the generator efficiency is 95%, as noted in Section 3, thus the baseline single turbine AEP for the LCOE analysis is 20,088 MWh.

Table 4.2. Electrical annual energy production sensitivity with generator efficiency.

Generator efficiency	Electrical AEP [MWh]
0.9	19,031
0.95	20,088
0.98	20,722

4.2 System Annual Energy Production Losses

The single turbine AEP values are converted to the final wind plant AEP by including the effects of wind plant power losses due to wake effects. The wake losses are highly dependent on a wind plant layout and the site wind rose. For example, speed up through wind plants caused by turbine blockage has been seen to increase performance of wind turbines within a wind plant [13]. In this analysis system wake effects are approximated as resulting in an average 5% reduction in the single turbine AEP. Downtime losses caused by turbine reliability and site accessibility are treated separately and are included in the operations and maintenance section later in this report. As a summary, the operations and maintenance downtime was estimated to result in a 94.2% turbine availability.

4.3 Increased Energy Capture Opportunities

For fixed geometry VAWTs there are cyclical variations in power and loads due to the 360° rotation relative to the freestream wind speed. This effect is reduced for large VAWTs due to the high tip speed ratio arising from the large radius, which may more efficiently capture power than HAWTs in the same wind conditions resulting from the effective double passage through the flow field due to the vertical rotation of the rotor [14]. However, once wind turbines reach their maximum operational rotational speed the tip speed ratio begins to decrease with wind speed from the design value, causing the amplitude of the cyclical variation of loads to increase. For this study, the rotor overturning moment (roll-pitch resultant) drove the platform design in the operational design load case. As a result of the decreasing tip speed ratio with wind speed, the maximum value for this moment occurred at rated wind speed.

The platform load margin at lower wind speeds is exploited in this study through the use of advanced controls. Optimal periodic controls can be used for increasing AEP, or alternatively for managing and reducing loads (e.g., platform loads, torque, load variability). Figure 4.1 shows the baseline power curve compared with optimal periodic controls set to maximize AEP, and constrained to not exceed the maximum platform overturning moment from the baseline power curve. The baseline curve was derived assuming a control strategy which fixes rotational speed for a given wind speed, whereas the advanced controls maximized AEP by allowing rotational speed and torque to vary (within prescribed limits), compared in Figure 4.2. For the same rotor and platform overturning moment ultimate load, the advanced controls result in an AEP increase from the baseline case of 16.1% to a value of 23,330 MWh. When also including the two sources of system energy losses described in the previous section, the VAWT wind plant capacity factor for the site of study becomes 48% for this advanced controls case.

The increase in energy capture from using advanced controls is accomplished by allowing the torque and rotational speed to vary from the constant rotational speed baseline control strategy, while maintaining the maximum allowable platform overturning moment. The optimal variation of torque and rotational speed for maximizing energy capture at each freestream wind speed was

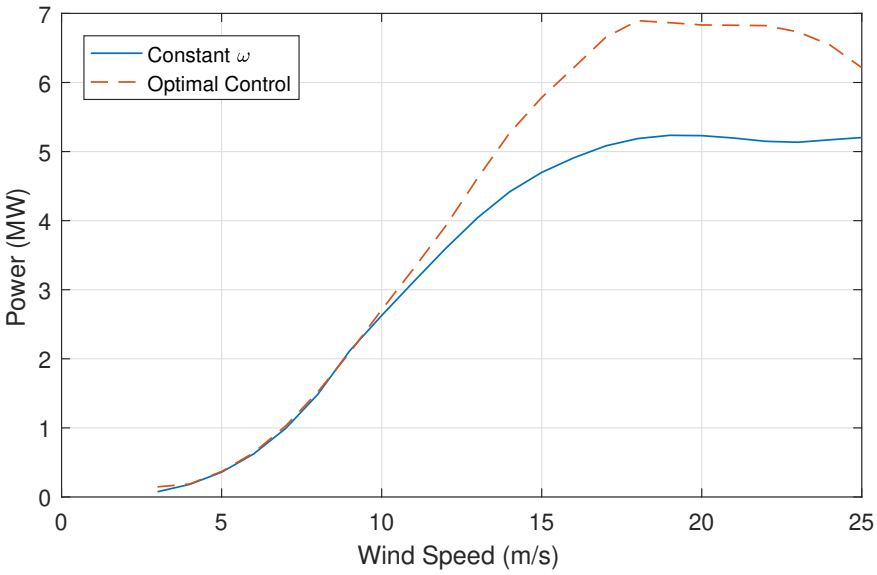


Figure 4.2. Sandia 5 MW VAWT power curve with advanced controls.

determined using an optimization of the parameter space, and the resultant for 18 m/s freestream wind speed is shown in Figure 4.3. This plot shows the limits and resulting optimal variation of torque and rotational speed for this case, compared to the same results for a constant rotational speed control strategy. The periodic optimal control forced the torque to a square wave that is common in optimal controls, known as a bang-bang or hysteresis controller. This is an interesting finding that may mean for optimal VAWT performance a different architecture for electrical conversion than an electromagnetic generator may be preferable. The control strategy optimizes energy capture as shown in the bottom sub-figure where the area above the baseline, dashed blue case is greater than the area below the baseline case.

The advanced controls strategy used increases AEP through more optimal control variation of rotational speed and torque, in addition to allowing the platform overturning moment at each freestream wind speed to increase to the extreme load value that was used to design the platform. This load margin was exploited at lower wind speeds as shown in Figure 4.4 where the optimal control case neared the platform overturning moment limit, as contributed by the roll and pitch moments (shown in grey).

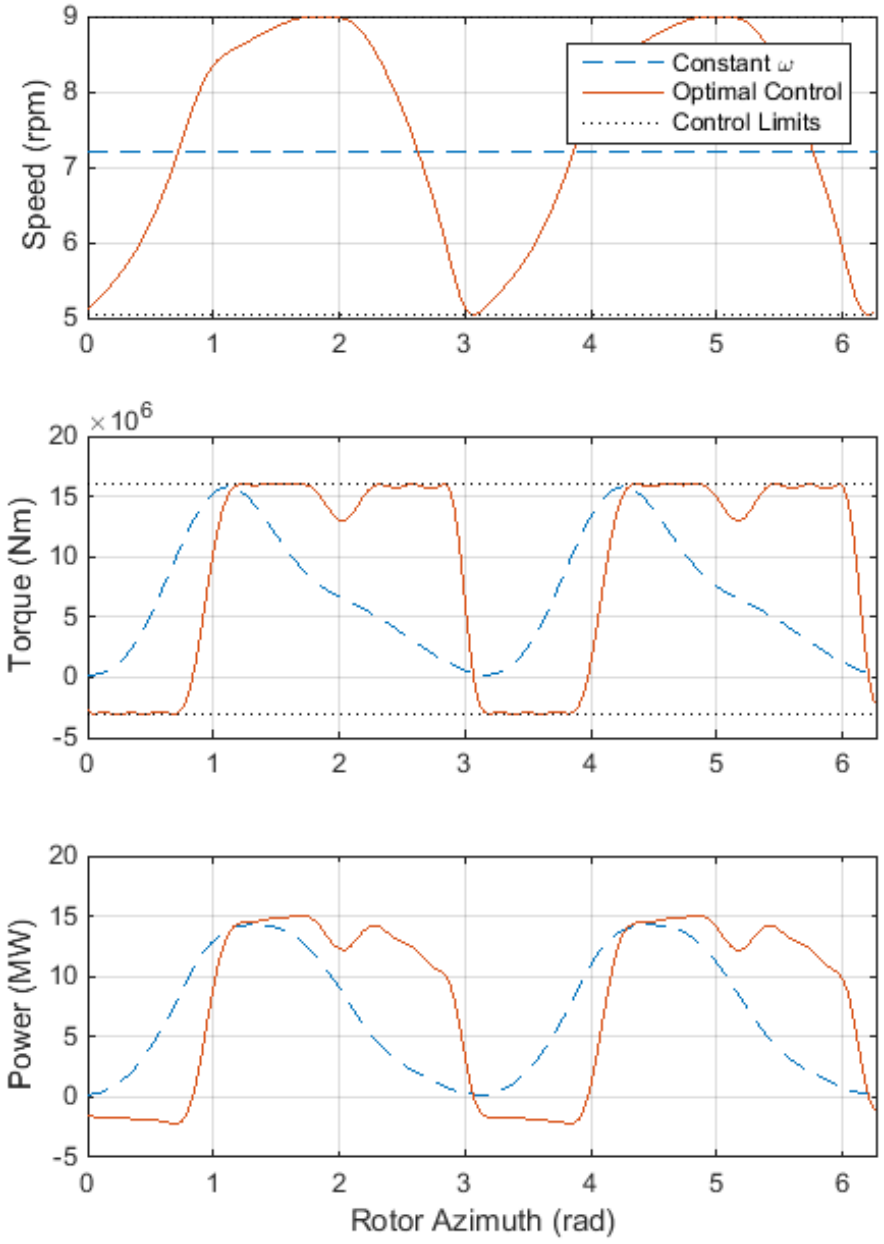


Figure 4.3. Performance variation using optimal controls at an 18 m/s wind speed.

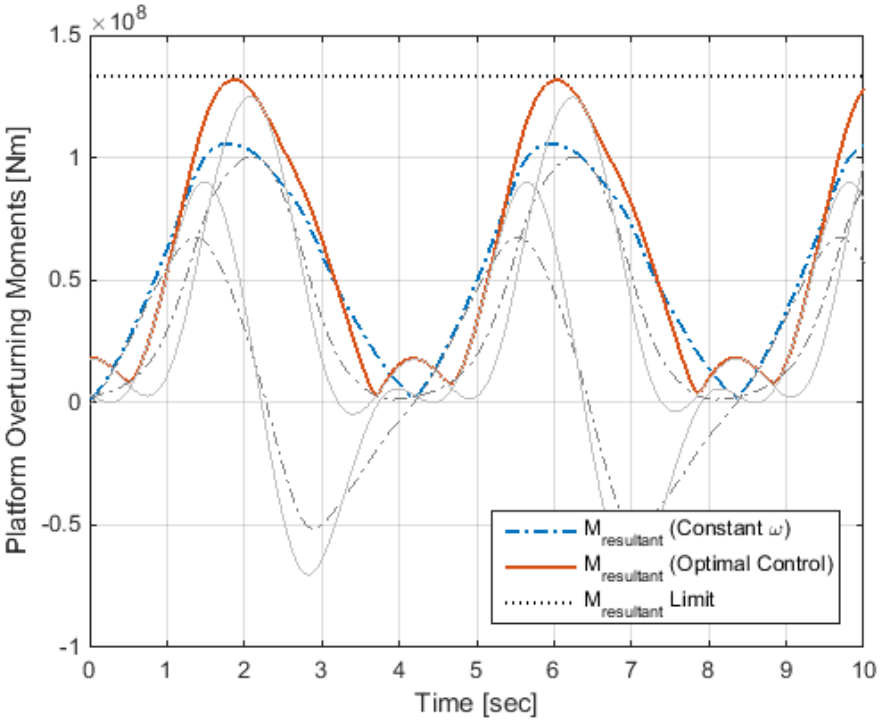


Figure 4.4. Platform overturning moment contribution using optimal controls at an 18 m/s wind speed.

Chapter 5

Platform Selection and Cost Analysis

As part of this work, a floating platform design study was performed to identify a solution specific to the design conditions of a floating VAWT. This study was done in collaboration with an industry partner experienced in floating system design from the offshore oil and gas industry, Stress Engineering Services (SES). The objectives of the platform design study were to determine the most technologically and financially promising platform architecture, and to provide a detailed cost estimate of the final platform design when paired with the Sandia DC_2B_LCDT VAWT rotor. The platform architecture design study is summarized in Section 5.1, and the final design and cost projections are summarized in Section 5.2. The detailed results of the platform design are given in Reference [2]. These projections and analysis serve as the basis for cost estimates used in the present study.

5.1 Platform Design Approach and Selection

To identify an optimal floating VAWT platform a design study was performed that compared numerous concepts with varying levels of development. From these concepts, six were identified as warranting additional evaluation with respect to performance and cost. These six concepts were selected to represent the full range of stability mechanisms available to floating systems, which was important to ensure that all fundamental floating solutions were considered; deep-draft ballasting, buoyancy/waterplane area, and mooring stabilized systems, as depicted in Figure 5.1. The preferred floating system architecture was unknown at the project start, and the initial phase of the platform design study focused on evaluating these different options for a floating VAWT. The six concepts analyzed as part of this first phase of the platform design study were:

1. Four-column semi-submersible
2. Classic spar
3. Ring pontoon
4. Compact (3-column) semi-submersible
5. Advanced spar
6. Multi-cellular tension-leg platform

These six platforms were sized based on the rotor topside properties stated previously in Ta-

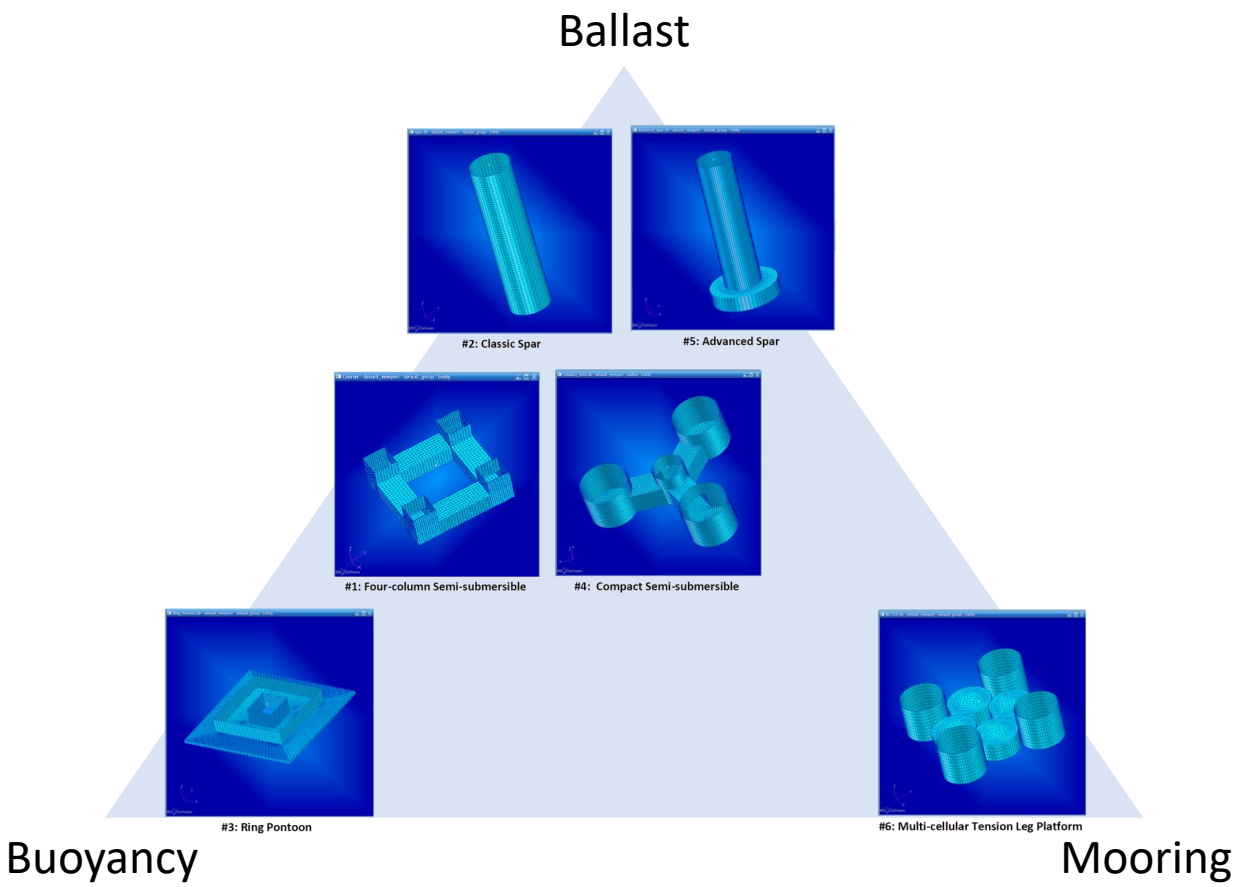


Figure 5.1. Platform architecture and stability mechanisms for the six platforms considered in the platform design studies.

bles 2.1 and 3.1. Factors were used from SES's industrial experience to approximate the mass and cost of the different components of each platform according to their complexity. Additional considerations in sizing the six representative platform models included:

- Suitability to the unique loading from a VAWT, including periodic loading from the rotor in yaw, pitch, and roll
- Maximum allowable heel angle was specified to be $\pm 10^{\circ}$
- Maximum allowable yaw angle was specified to be $\pm 10^{\circ}$
- System natural periods of each candidate floating system were designed to avoid the peak period of the site's wave spectrum (10 sec), and the periods associated with the twice per-revolution (4.17 sec) and four times per-revolution (2.08 sec) turbine design speed
- Vessel freeboard was estimated based on the design storm significant wave height (8.0 m) and the semi-diurnal water depth variation (4 m) and determined to be 20 m for tension-leg platforms and 15 m for all other vessel types
- Redundancy in mooring and vessel buoyancy compartmentalization

- Hull design for tow-out capability with topside fully installed, when feasible for the different systems

The cost estimate comparing the six platforms considered total fabrication and installation costs of the various platforms to capture the differences between the systems and the effect on total platform cost. To accomplish this comprehensive cost comparison, cost estimates included tow-out of the floating platform, ballasting of the platform, installation of the VAWT (quayside or offshore), installation of anchor piles and mooring lines, connection of subsea transmission cables, vessel mobilization and charter costs, and removal of installation equipment. The phase 1 design study cost comparisons produced by SES are shown in Figure 5.2. The total cost is broken down into fabrication, mooring, and installation costs in Figures 5.3. From this analysis, it was concluded that the four-column semi-submersible, spar, and multi-cellular tension-leg (McTLP) platforms were the most favorable platform options from a cost perspective, with the McTLP having the lowest average cost estimate.

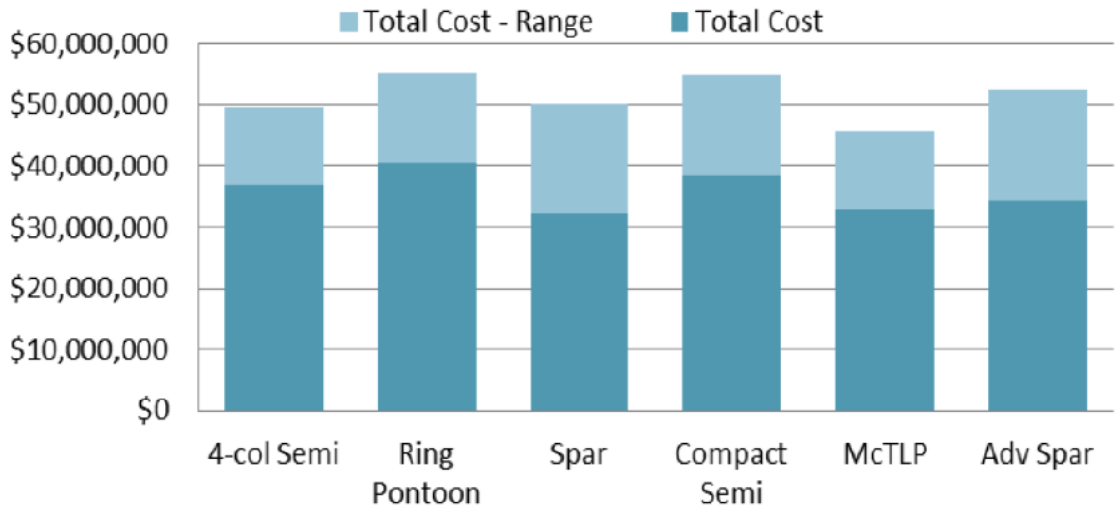


Figure 5.2. Platform estimated total cost comparison from Phase 1 design study [2].

The favorable cost estimate of the McTLP came from reductions in mooring and installation costs, as identified in Figures 5.3. Despite having tensioned mooring, the significant reduction in its required length produces a mooring cost that is nearly half that for the non-tensioned systems at the study site's 150 m water depth. Installation costs also favored the McTLP for two main reasons. The two spar systems were considered to require VAWT installation at sea producing the highest cost estimates for installation. Of the remaining systems which allowed for VAWT installation at port, the McTLP produced an additional cost savings due to the tight footprint of the mooring system which reduced the complexity of this portion of the installation procedure and cost. The estimated maximum values for the range of fabrication costs were nearly constant between the two spar systems, the four-column semi-submersible platform, and the McTLP, while the minimum values of these ranges favored the classic spar system. The spar systems offer reduced complexity

over the multiple column, McTLP platform, however, being ballast-stabilized systems requires a much deeper draft resulting in a higher material demand in the hull design. The material usage shows up in the lightship weight for the spar platform of 40,721 kN compared with 38,069 kN for the McTLP. The increased range of the spar fabrication costs compared to the four-column semi-submersible and McTLP platforms results partly from the market volatility of steel costs and the increase in material usage for the spar platforms. Table 5.1 shows the required vessel dimensions and some of the hull and mooring properties as sized for the Sandia VAWT design.

In addition to the initial cost estimate, the platforms were compared by considering the ability to reduce costs beyond their estimates. The additional cost-related evaluation metrics that were considered include:

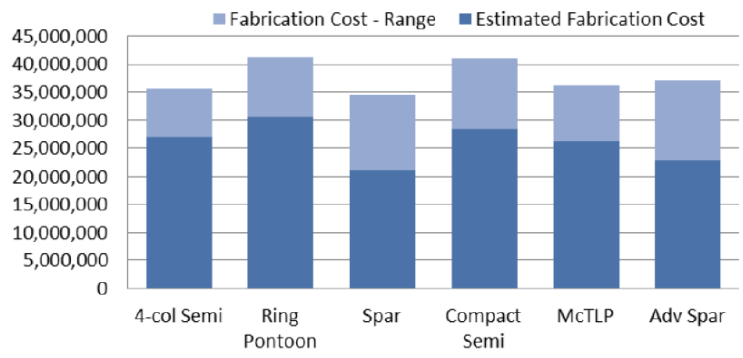
- Amenability to mass production
- Potential for further optimization
- Hull fabrication simplicity
- Ability to dry dock turbine
- Decommissioning and maintenance costs

System cost was not the only consideration in selecting the optimal platform, particularly since the four-column semi-submersible, spar, and McTLP platforms all had similar values from the cost estimate. The system performance was considered along with the cost estimate and cost-related evaluation metrics to assess the platforms. Some of the qualitative performance metrics considered include:

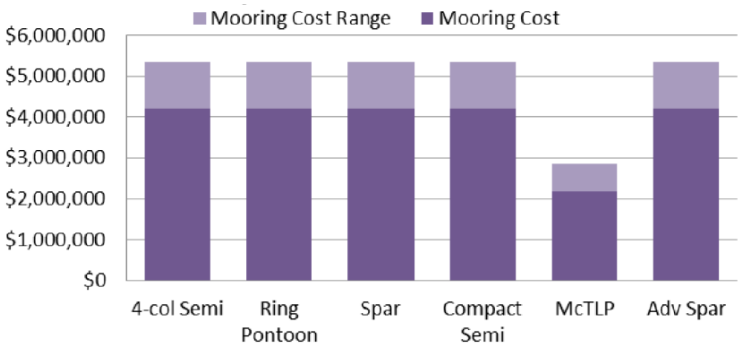
- Field-proven hull/mooring performance
- Water depth scalability; depth independence
- Potential sensitivity to fatigue
- Simplicity over complexity with robustness to survive in the open ocean
- Wind plant installation and simplicity of seafloor layout
- Innovation which can lead to a lower cost

The platform systems were analyzed by these, and other, performance criterion with the conclusions summarized in Figures 5.4. These graphs display the platform's potential to reduce capital expenditures compared with the performance criterion of technical performance, reliability or technology readiness level, and operational expenses. The conclusion that the McTLP has the greatest potential to reduce capital costs displayed in these figures was supported by a favorable amenability to mass production and the greater potential for platform optimization that can lead to a lower cost. The lower technology readiness level of the McTLP that is favorable from the ability to reduce platform costs also results in a lower ranking in system reliability. The classic spar and four-column semi-submersible have proven reliability from the oil and gas industry and ranked high in the concept reliability.

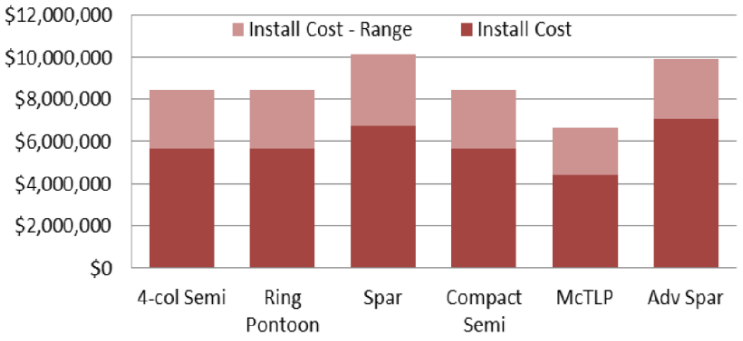
Of the six candidates considered in the selection phase, Sandia and SES decided that the McTLP offers the best combination of performance and cost and was identified as the optimal



(a) Fabrication costs



(b) Mooring procurement and fabrication costs

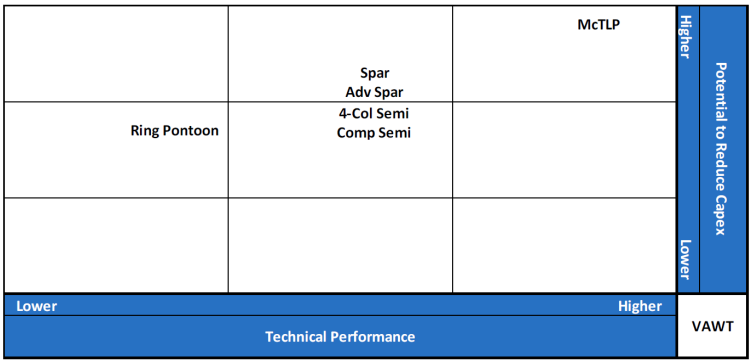


(c) System installation costs

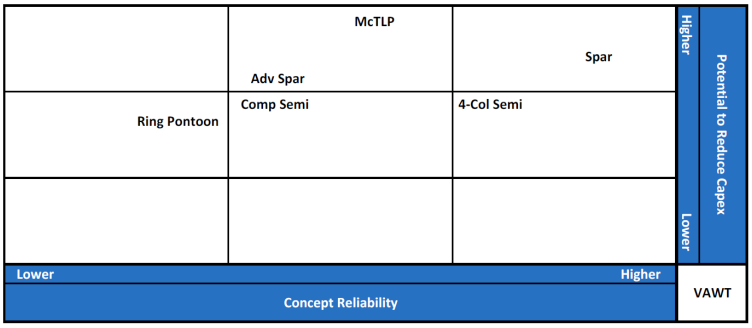
Figure 5.3. Platform estimated cost component comparison from Phase 1 design study [2].

Table 5.1. Hull and mooring properties and resulting cost estimates for the Phase 1 platforms [2].

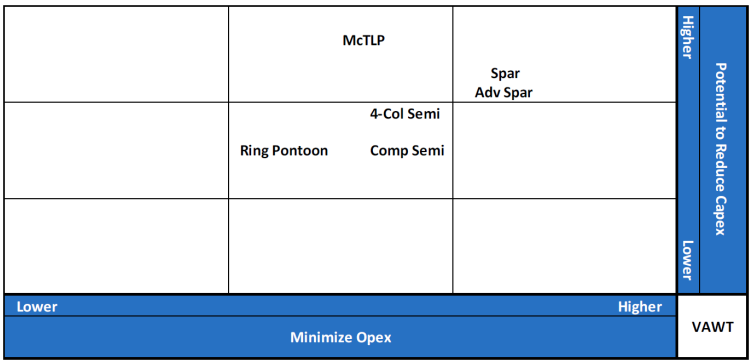
Performance and Cost Details			Phase 1 Design Concepts					
			#1 Four-column Semi	#2 Classic Spar	#3 Ring Pontoon	#4 Compact Semi	#5 Advanced Spar	#6 Multi-cellular TLP
Design Iteration		--	2	2	1	1	1	1
Vessel Width at Keel		*m*	37	12	44	37	32	32
Vessel Draft		*m*	10	100	6	11	50	10
Displaced Volume		m^3	5,858	11,310	5,038	4,726	15,200	6,174
Displacement		*kN*	58,895	113,699	50,649	47,511	152,808	62,069
KB		*m*	3.6	50	2.4	5.0	20	4.1
BM		*m*	7.6	0.090	9.2	8.3	0.283	9.2
KM		*m*	11	50	12	13	20	13
KG		*m*	7.6	43	7.5	9.4	18	8.9
GM		*m*	3.6	7.3	4.1	4.0	2.5	4.3
Lightship Weight		*kN*	32,706	40,721	33,099	29,705	46,528	38,069
Vertical Mooring Tension		*kN*	270	270	270	270	270	24,000
Water Ballast		*kN*	25,919	6,322	17,280	17,536	3,521	0
Entrained Water		*kN*	--	66,386	--	--	102,489	--
Total Supported Weight		*kN*	58,895	113,700	50,649	47,511	152,808	62,069
System Natural Periods	Surge	*sec*	53.8	36.9	50.9	46.1	96.4	42.4
	Sway	*sec*	53.8	36.9	50.9	46.1	96.4	42.4
	Heave	*sec*	19.4	22.5	14.2	9.1	20.9	2.7
	Roll	*sec*	25.1	32.5	31.4	18.8	63.1	2.6
	Pitch	*sec*	25.1	32.5	31.5	19.0	63.2	2.6
	Yaw	*sec*	38.5	18.4	24.4	23.3	17.5	29.1
Estimated Fabrication Cost		*MM USD*	27 - 36	21 - 34	31 - 42	28 - 42	23 - 37	26 - 36
Estimated Mooring Cost		*MM USD*	4.1 - 5.2	4.1 - 5.2	4.1 - 5.2	4.1 - 5.2	4.1 - 5.2	2.1 - 2.8
Estimated Installation Cost		*MM USD*	5.8 - 8.1	6.8 - 10.0	5.8 - 8.1	5.8 - 8.1	7.0 - 9.9	4.3 - 6.2
Estimated Total Cost		*MM USD*	37 - 50	32 - 50	41 - 55	39 - 55	34 - 53	33 - 46



(a) Comparison of technical performance



(b) Comparison of concept reliability



(c) Comparison for reducing operational expenses

Figure 5.4. Platform performance comparison of the Phase 1 concepts [2].

platform for a floating VAWT at the site of study. The McTLP had the lowest platform and installation cost estimate in addition to the greatest potential for platform optimization and further cost reduction. This platform offered additional performance benefits which made it favorable overall. The McTLP enables a simplified seafloor layout of mooring lines and anchors which is advantageous from a wind plant installation perspective. This platform also has the lowest installation and decommissioning costs, likely allowing for major turbine repairs to be performed more cost-effectively at port by towing the system back for these repairs. The most significant performance benefits of the McTLP is probably the small roll, pitch, and yaw motions compared to the other platforms. The maximum angular displacements under the operating conditions for the three most-promising platforms are compared in Table 5.2. The small roll and pitch moments are beneficial in terms of energy capture from a static sense, and significantly reduce inertial loading on the blades and tower from a dynamic sense. The classic spar and McTLP share this advantage, but the McTLP has a benefit over the spar in reduced yaw motions. The smaller yaw motions are helpful from a controls perspective since the VAWT torque is applied in the yaw direction and considering its periodic nature.

Table 5.2. Maximum platform motions from Phase 1 designs.

	Roll motion [deg]	Pitch motion [deg]	Yaw motion [deg]
Four-column semi-submersible	19.9	19.9	6.4
Classic spar	1.4	1.4	14.8
Multi-cellular tension-leg platform	0.3	0.3	5.3

5.2 Detailed Platform Design and Cost Estimation

The multi-cellular tension-leg platform was identified as the optimal platform for a VAWT at the site of study from performance and cost considerations during the initial design study. The second phase of the platform design study involved more detailed design of the McTLP hull and mooring to produce a more realistic platform design and cost estimate that could survive the loading requirements when paired with the DC_2B_LCDT rotor. This detailed design phase included dynamic analysis and sizing of the hull based on four design load cases corresponding to (1) an extreme 50-year return wave loading case, (2) maximum turbine operational loads, (3) mooring fatigue analysis from turbine operation and wave distributions, and (4) tow-out stability with fully integrated topside. The final McTLP platform at the conclusion of the design study is shown in Figure 5.5.

The design process iterated between simulating time-series of VAWT loads, which include inertial effects from the platform motions, and a redesign of the platform with updated representative mass and stiffness properties, which was repeated until convergence. The final design iterations are listed in Table 5.3, with descriptions of the requirement not met for that iteration. A challenge that is unique to tension-leg platforms that was addressed through the design process is that

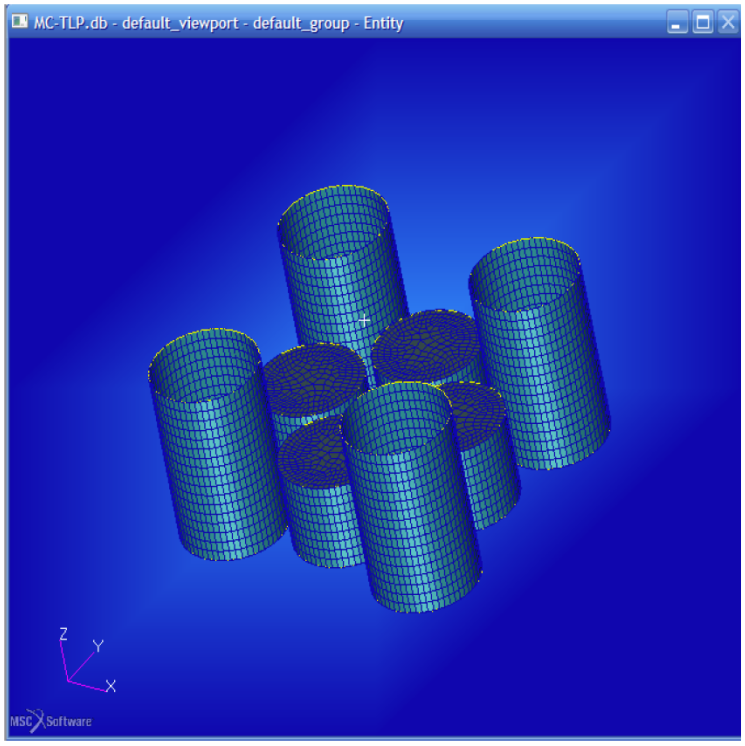


Figure 5.5. Patran model of the final McTLP hull [2].

the tensioned mooring cannot be allowed to go slack. Wind turbines have substantial overturning moments due to the turbine thrust (in addition to side-side moments for VAWTs), which must be met with sufficient platform roll/pitch stiffness to maintain the mooring tension above a minimum design threshold. This requirement results in highly stable platforms with very small roll and pitch motions for the McTLP, which is favorable regarding turbine performance as described previously. Satisfying the minimum tendon tension requirement was identified as the design driver for operational design load cases, which was met with design iteration 2. This design satisfied all operational cases, including mooring fatigue, but the platform was determined to be unstable during tow-out ballasting. The ultimate design driver for the platform was the tow-out design case which required an increase in hull mass and volume to produce the final hull design in iterations 3 and 4. For the platform study, SES decided to use standard dimensions which resulted in a discrete increase from a 10 m diameter hull to 11 m.

An optimal turbine-platform system would operate with similar design margins for the operational design cases as for the tow-out design case. Design iteration 2 satisfied the operational design cases, and these platform dimensions will be used in the LCOE projections in Section 8.2 to describe the "optimal system platform" costs. SES estimated fabrication costs for the McTLP platform based on historical, commercial data which scaled the hull mass. The cost of an optimal platform is then estimated as the ratio of the lightship weight between design iterations 2 and 4, meaning that the optimal system platform cost is approximated as 29,510/34,148 or 86.4% of the

Table 5.3. Phase 2 platform design iteration summary [2].

Design Iteration	Cell Diameter m	Vessel Draft m	Lightship Weight N	Tendon Diameter mm	Tendon Tension N	Reason for Next Design Iteration
1	11.6	10.0	38,069	114	3000	Tendons slack during 50-yr event Draft too shallow
2	10.0	17.2	29,510	153	3000	Instability when ballasting down Columns are too slender
3	11.0	17.2	34,148	153	3000	Tendons slack in operational case Tendon pretensions too low
4	11.0	17.2	34,148	153	3500	n/a

platform fabrication cost estimates.

After completing the final platform design, SES produced final cost estimates for the fabrication, mooring, and installation of the platform with turbine installed. These cost estimates were based on proprietary cost data from one-of-a-kind floating platforms designed and built for companies in the oil and gas industry.

Fabrication costs were estimated using the data normalized with hull weight, and includes project management, engineering, overhead, profit, and certification. Engineering and project costs were spread across 100 units, and represent 10.9% of the total fabrication costs. The remainder of the hull fabrication costs consist of 5.3% for the turbine support structure, 20.1% for the inner columns, and 63.4% for the outer hull columns. A reduction factor was applied to these data to produce the lower bound estimate which took into consideration the high-level of specifications required for major oil companies and the reduced design margins appropriate for the unmanned VAWT platforms. These data represent the most similar information available to SES for the platform fabrication, however, the requirements for offshore oil rigs compared with floating wind turbines should differ significantly due to the capital involved, higher design margins required for manned oil rigs, and the operation of the distinct systems. As a result of the differences, and with understanding of the cost estimation process used, it is determined that the design and fabrication costs of the hull are best represented by the lower bound of the estimate which is defined as the most likely fabrication cost in the system LCOE analysis.

Mooring costs were estimated using the commercial data normalized by water depth. Factors were applied to represent the likelihood that mooring connection standardization could be utilized compared to the customized connections required for the single production volume data used. The reduction factors defined by SES are stated to also allow for a degree of uncertainty in the geotechnical information. Platforms for offshore wind plants differ substantially from the oil and gas industry in that they are sufficiently high volume to obtain standardization and reductions in costs. Based on the explanation of the cost estimates, and the relatively high volume for the

platforms, the most likely mooring cost is defined as the lower bound from the estimates.

Installation costs were estimated from the determined vessel types required, number of days for installation at the site of study, and using typical day rates and mobilization costs for the corresponding vessels. To accomplish the installation SES assumed that 3 ocean tugs were used to transport the platform, and 1 anchor handling vessel is used for each installation. Installation of the anchor piles for each platform is assumed to take 3 days to install, which happens independent of the platform installation, distributing the mobilization cost over the 100 wind turbine wind plant. Using the three tugs, it is assumed to take 2 days to transport the hull 25 km to the site, and 2 additional days to connect the hull to piles. The final installation steps are assumed to take 1 day each; connect power cables, ballast hull to set tensions, remove hull equipment, and startup of the VAWT. This estimate results in a total number of calendar days to install one VAWT system of 11 days. The total installation cost consists of 19.2% vessel mobilization costs, 60.5% vessel charter and fuel costs, and 12.4% labor costs. The vessel mobilization scheme assumes that the anchor piles for the 100 wind turbines are installed from one mobilization, but that each platform is installed separately with full mobilization costs for the three tugs and one anchor handling vessel. This treatment for platform installation assumes that a second platform would not be available to install in the 4 days required to transport and connect a platform. An improved approach might include staging a series of platforms for installation to distribute the mobilization costs. This approach will be described as an improved installation procedure and will assume that 5 platforms can be installed from one series of vessel mobilizations. This approach results in the platform installation vessel mobilization charges being distributed amongst 5 units, reducing installation costs by 15.3%. Cost factors were applied to reflect the volatility of vessel costs due primarily to vessel availability. It should be assumed that scheduling of these known operations would remove most of the uncertainty due to vessel availability, but to account for the likelihood of unplanned delays the most likely value for installation costs is taken as the mean of the lower and upper bounds.

Greater detail on the cost contributions for the three main categories can be found in the platform design reports [2]. Based on the descriptions of the SES cost estimates, Table 5.4 shows the lower bound, upper bound, and most-likely values for the main components of turbine platform costs. In the LCOE analysis, the most likely value will be taken as the baseline case, $25.5MM, and the upper bound will be included as a worst-case approximation, $34.03MM. These cost estimates differ from those in the initial design study in Section 5.1 for several reasons. In producing the final cost estimates SES included the effects of economies of scale for the high-volume production, fabrication cost reductions reflecting a volume discount on the large steel order and efficiencies gained from manufacturing 100 units, and the distribution of engineering and certification costs among the 100 units.

Based on the level of design definition achieved at the end of the detailed phase of this work, SES stated that the cost estimates can be considered Class 3 estimates in terms of the system published by AACE International [2]. According to AACE International, the expected accuracy range of these estimates is $\pm$25%. To represent the current level of design and the likelihood and potential of design improvements to reduce the cost to meet the low end of this stated accuracy range, a case is described where this 25% reduction is achieved. This future cost scenario is described as the mid-term cost reduction which reduces the lower-bound of the SES estimates by 25%, includ-

ing the reductions from considering the optimal system platform cost and improved installation procedures. The improved design projections on the platform costs are listed in Table 5.5. The estimated costs establish a range for the floating system capital costs and system installation costs.

Table 5.4. Platform cost estimates produced by SES and the most-likely value.

	Lower Bound [MM USD]	Upper Bound [MM USD]	Most-Likely Value [MM USD]
Fabrication cost	18.09	24.89	18.09
Mooring cost	2.18	2.86	2.18
Installation cost	4.18	6.28	5.23
McTLP baseline	24.45	34.03	25.5

Table 5.5. Platform cost estimate projections.

	Fabrication Costs [MM USD]	Mooring Costs [MM USD]	Installation Costs [MM USD]
Optimal system platform cost	$0.864 \times 18.09 =$ **15.63**	–	–
Improved installation procedure	–	–	$(1-0.153) \times 5.23 =$ **4.43**
Mid-term 25% cost reduction	$0.75 \times 15.63 =$ **11.72**	$0.75 \times 2.18 =$ **1.64**	$0.75 \times (1-0.153) \times 4.18 =$ **2.66**

5.3 Additional Supporting Sources for Selection of the Tension-Leg Platform

The optimal floating platform architecture is dependent on the topside properties and water depth. The current trends for floating platform development for horizontal-axis wind turbines within the industry mostly utilize spar designs and semi-submersible platform types. Additional sources are presented in this section to support the identification of the multi-cellular tension-leg platform as the optimal platform for the site of study in the present analysis.

Myhr analyzed eight different offshore wind turbine systems with a horizontal-axis wind turbine to predict the system levelized cost of energy [15]. Six floating and two fixed-bottom offshore systems were included in the analysis, and the floating platforms included spar, semi-submersible, and tension-leg platform concepts for water depths up to 500 m, as shown in Figure 5.6. Myhr found that the four mooring stabilized, tension-leg platform concepts produced the lowest system

LCOE for water depths up to about 300 m. The two concepts most similar to traditional tension-leg platforms (TLB B, TLB X3), and to the McTLP, resulted in the lowest system LCOE for water depths up to 250 m. These tension-leg platforms concepts were shown to even result in lower costs than the fixed-bottom jacket foundations up to these water depths.

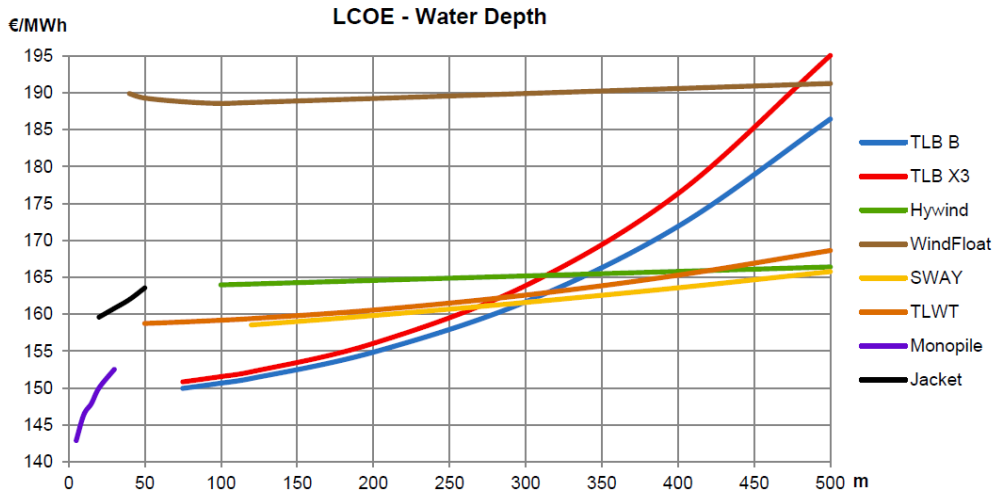


Figure 5.6. The sensitivity of levelized cost of energy for offshore sites to platform architecture and water depth [15].

In the platform analysis with SES, the identification of the McTLP as the optimal platform architecture was based partly on the qualitative ranking of the ability for future reduction in platform costs. The McTLP had an estimated cost which was lower than the leading spar and semi-submersible platforms, and the potential for further cost reduction provided additional justification for the selection. A report published by the Crown Estate supports the expectation of potential for tension-leg platforms to see further cost reductions [16]. Figure 5.7 plots the technology readiness level (TRL) of the three leading platform types from this study. The tension-leg platforms are at a lower TRL than the spar and semi-submersible architectures which likely means there is greater margin for cost reduction as stated in the study with SES. The lower TRL of the tension-leg platforms (TLP) is likely also related to why the leading concepts currently are mostly only spar and semi-submersible concepts, due to their extensive utilization in the offshore oil and gas industry.

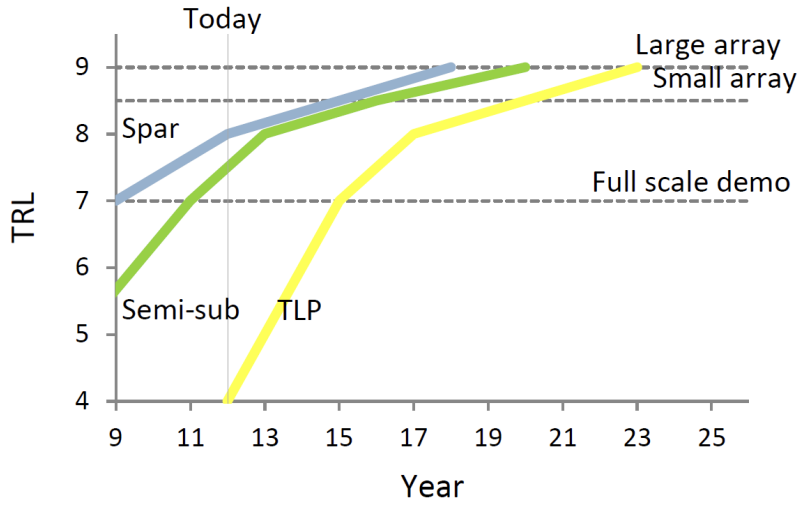


Figure 5.7. Technology readiness level for different floating platform architectures [16].

Chapter 6

Additional Capital Expenditure Cost Analysis

The remaining capital expenditures to be estimated are the balance of system and the finance cost categories. The balance of system cost includes those associated with development, electrical infrastructure, port and staging, platform-turbine assembly, and wind plant installation and commissioning. In this analysis, balance of system cost is defined to not include the turbine platform and mooring costs, which is included in the turbine capital cost. The financial cost consists of contingency, construction finance, insurance, and decommissioning. To estimate these two sources of capital expenditures, the NREL Offshore Balance of System (BOS) Model has been utilized [17].

6.1 Baseline Balance of System Cost Estimate

Balance of system costs were calculated for the baseline wind plant described in Table 6.1 using the NREL BOS model. The model calculates some of the costs based on the initial capital expenses which were set to match those from this study where possible in the model. The model was developed using data from HAWT wind plant costs, which are treated as constant for the VAWT wind plant of study. This distinction may be most significant for the project costs of development, engineering and management, and port and staging costs, which are not a significant portion of the resulting LCOE. The electrical infrastructure and installation costs are calculated for the baseline wind plant array with a 7-by-7 rotor-diameter spacing. This array size was chosen for the wind plant to represent trends in offshore wind plant array spacing for offshore HAWT wind plants, and to account for the likely improved wake recovery for VAWTs relative to HAWTs due to the increased wake-generated turbulence.

The balance of system costs were determined using the BOS model in addition to the SES platform cost estimates. These costs are calculated for the baseline scenario as summarized in Table 6.2, with the data source and assumptions listed. In calculating the costs using the BOS model the default parameters of the calculations were unchanged. The development cost is calculated as $15MM front-end engineering, $17.6MM permitting studies and compliance, $5.8MM meteorological tower installation, and $44.7MM for decommissioning expenses. The engineering and management costs are calculated as 4% of the procurement and installation costs in the BOS model. Since these overhead costs are included in the SES cost estimates (representing 10.9% of

Table 6.1. Electrical infrastructure costs for wind plant with 100 floating VAWTs.

Parameter	Value	Units
Number of turbines	100	#
Turbine rating	5	MW
Rotor diameter	108	m
Turbine array spacing 1	7	Rotors
Turbine array spacing 2	7	Rotors
Distance to export cable landfall	25	km
Water depth	150	m

the fabrication cost) they will not be added separately. The electrical infrastructure cost includes estimates for subsea cable cost, offshore substation cost, and onshore transmission infrastructure cost. Port and staging costs are calculated for the wind plant with values of $3.55MM for port costs and $12.7MM for staging costs. The staging costs represent those associated with installing the turbine on the platform, which was included in the SES installation cost estimate and is removed from this portion of the BOS costs. Assembly and installation of the wind plant and connection to electrical transmission is calculated by the SES estimate. The assembly and installation costs also include the cost of the subsea electrical transmission system, which is estimated from the BOS model. Wind plant commissioning is described to be included in the installation cost estimate from SES, which is treated as 1% of the hard costs in the NREL BOS model.

Table 6.2. Baseline wind plant balance of system costs and data source.

Component	Cost	Units	Source
Development	83.06	MM USD (total)	BOS
Engineering and Management	included in SES cost estimates	–	SES
Port and staging	3.55 *port costs only	MM USD (total)	BOS/SES *staging costs included in SES installation cost
Electrical infrastructure	279.66	MM USD (total)	BOS
Assembly and installation – Wind plant installation	5.23	MM USD (per turbine)	SES
Assembly and installation – Electrical installation	104.99	MM USD (total)	BOS
Wind plant commissioning	included in SES cost estimates	–	SES
Total baseline balance of system capital expenditure	9.94	MM USD (per turbine)	

6.2 Baseline Financial Cost Estimate

The financial costs represent additional costs on the installation and decommissioning of the wind plant. This is described as including installation and procurement contingency, construction finance costs, insurance during installation, and decommissioning costs. The NREL BOS model default defines contingency costs as 30% of installation costs and 5% of component procurement costs. The SES cost estimates were careful to capture the effect of variability in installation and fabrication, and they are used to represent the contingency costs over the BOS model. Construction finance costs are calculated as 3.9% of the cumulative initial capital costs, and insurance is calculated as 1% of the costs. Decommissioning is not included in the current version of the BOS model for financial costs, however decommissioning related activities were included in the BOS model development cost as described previously. A summary of the financial costs for the baseline case is given in Table 6.3.

Table 6.3. Baseline wind plant financial costs and data source.

Component	Cost	Units	Source
Contingency	included in SES cost estimates	–	SES
Construction finance	1.046	MM USD (per turbine)	BOS
Insurance	0.268	MM USD (per turbine)	BOS
Decommissioning	–	MM USD (per turbine)	BOS
Total baseline financial capital expenditure	1.314	MM USD (per turbine)	

This page intentionally left blank.

Chapter 7

Operations and Maintenance Costs

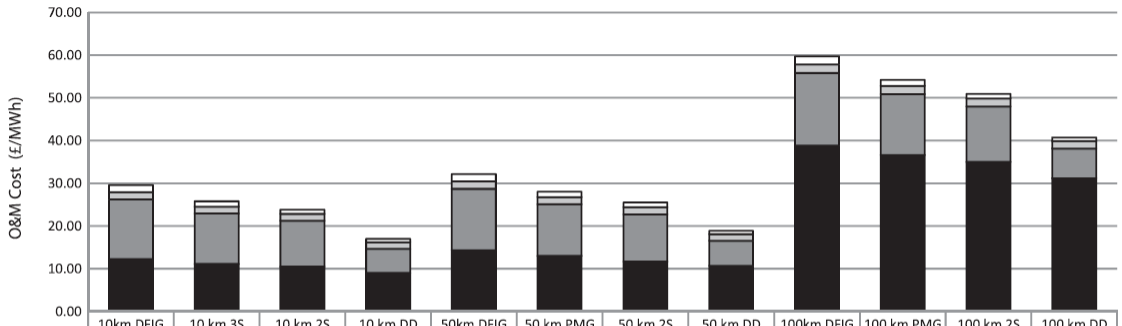
7.1 Baseline Operations and Maintenance Costs

Wind energy system reliability affects the levelized cost of energy (LCOE) in two main ways. There is an associated, direct operations and maintenance cost (O&M) for the system repair that includes labor, parts, and repair vessel costs. In addition to the cost of the actual repair, there is a loss of energy production for repairs that require the turbine to stop operating until serviced, a downtime cost. These two "costs" will be treated separately in the cost model since the downtime affects the system AEP, however they are both sourced from the same technical issue which is the system reliability. In comparison to other sources, the sum will be described in this report as the "combined O&M cost." For offshore wind plants the O&M costs can become a significant contributor to the LCOE. These costs increase with distance from shore where vessel charters require additional time and adequate weather windows must expand, increasing the turbine downtime. The combined O&M system costs have been commonly treated and reported to be on the order of 20% of the LCOE for existing, fixed-bottom offshore wind plants [15, 18].

Recent research has characterized O&M costs using data from around 350 offshore wind turbines from multiple wind plants over a 5-year period [18, 19, 20]. These data have been analyzed to model the impact of design decisions on O&M costs, in addition to analyzing the effect of distance from shore. Figure 7.1 compares the effect of drivetrain O&M related costs for different generator architectures. The data in this study did not include the two relatively new configurations for the two-stage and direct-drive permanent magnet generator drivetrains. These failure rates were estimated using a methodology that incorporates the available historical data to estimate the system reliability. For the dataset and offshore locations studied, these findings support the decision for the SNL VAWT design to utilize a direct-drive permanent magnet generator drivetrain despite the higher initial price.

This data set was also analyzed to quantify the occurrence of turbine system failures from recorded maintenance services, for all mechanical systems [19]. Failures were defined as requiring a visit to a turbine outside of scheduled maintenance and where material was consumed. Failures are categorized based on material cost as major or minor replacements or repairs and based on the associated turbine system, shown in Figure 7.3. There is not a record of downtime losses or transport costs associated with the recorded services.

This analysis revealed 8.3 failures per wind turbine per year. Of these failures, 1.08 were due

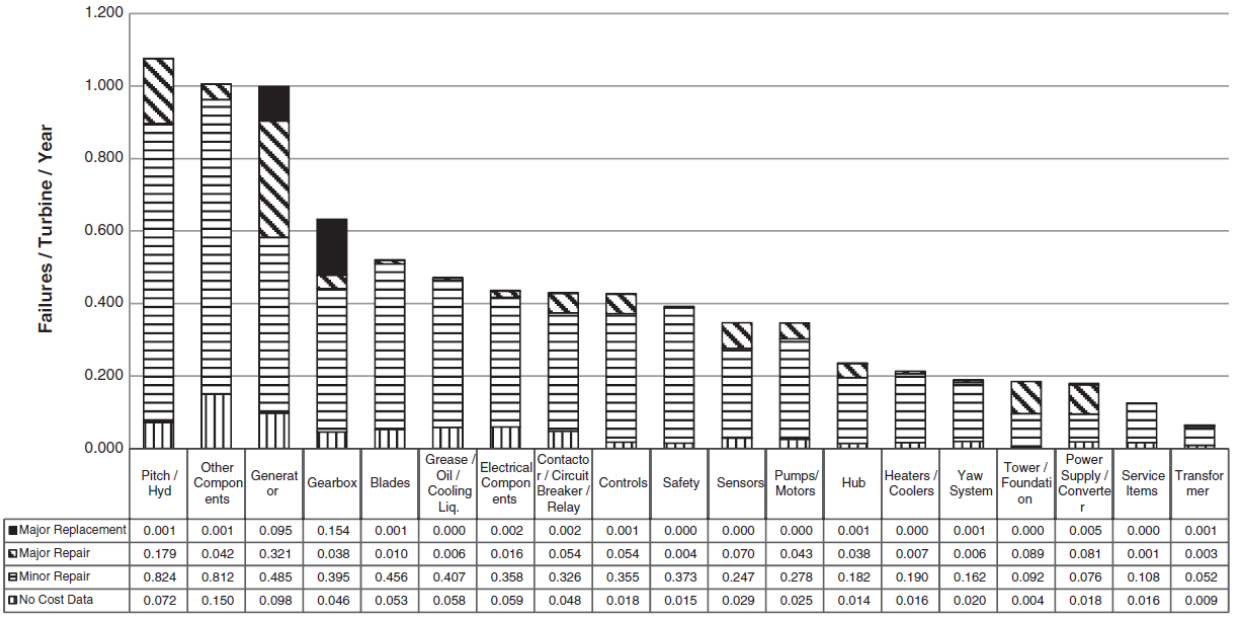


	10km DFIG PRC	10 km 3S PMG FRC	10 km 2S PMG FRC	10 km DD PMG FRC	50km DFIG PRC	50 km PMG FRC	50 km 2S PMG FRC	50 km DD PMG FRC	100km DFIG PRC	100 km PMG FRC	100 km 2S PMG FRC	100 km DD PMG FRC
Repair Costs (£)	1.61	1.26	0.94	0.79	1.65	1.26	1.15	0.80	1.88	1.46	1.08	0.89
Staff Costs (£)	1.71	1.63	1.6	1.49	1.74	1.65	1.65	1.5	2.01	1.9	1.85	1.71
Transport Costs (£)	13.95	11.75	10.73	5.66	14.37	12.05	11.06	5.88	17.03	14.24	13	7.02
Lost Production Costs (£)	12.26	11.16	10.53	9.04	14.37	13.03	11.68	10.72	38.81	36.63	35	31.13

Figure 7.1. Drivetrain-related operations and maintenance costs considering different drivetrain types [20].

to pitch/hydraulics systems and 0.19 were from yaw system failures. VAWTs do not require yaw systems and there is not a pitch-able portion of the blades for the Sandia Darrieus VAWT so these two systems are eliminated. The reliability is improved due to the removal of these two failure sources. There are hydraulic systems on VAWTs, so to account for that it is assumed that 90% of the pitch/hydraulics category of failures which require a visit to the turbine are due specifically to the pitch system. The Reliawind study [21] showed that approximately 23% of downtime losses are due to pitch systems, with only about 2% of downtime losses due to the hydraulic systems which makes the 90% contribution from pitch systems a reasonable assumption. The removal of these two systems, by this analysis, would reduce the total number of failures by 13.9%. This improvement in reliability will be used to scale the O&M direct costs and to reduce the O&M downtime losses for the VAWT system. Not all of the failures require the same amount of downtime, so this is an approximation. However, pitch and yaw systems are operational systems and would likely require turbine shutdown if these components have failed. Largest downtimes come from failures requiring jack-up vessels, such as the drivetrain failures. Many of the systems shown in Figure 7.2 would not require delayed charters or as strict of weather conditions, therefore it is approximated that although the pitch and yaw systems reduce failures by 13.9%, that the failures listed don't all require equal downtime and the pitch and yaw system failures may represent a larger percentage to downtime losses than their failure percentage and is viewed as a reasonable approximation.

Carroll estimated the availability for a direct-drive permanent magnet generator drivetrain, which was used as the best estimate for the site of study in this analysis. For the offshore site of study in this analysis which is 25 km from shore, the value for a 30 km distance is used with a turbine availability of 93.3%, shown in Figure 7.3. Using the 13.9% reduction in failures described above, the turbine availability used in this study is determined to be 94.2%. As an additional reference, a report on offshore wind plants in the United Kingdom stated that existing offshore wind farms in 2013 typically achieved between 90-95% availability, compared to land-based wind tur-



	Pitch / Hyd	Other Components	Generator	Gearbox	Blades	Grease / Oil / Cooling Liq.	Electrical Components	Contactor / Circuit Breaker / Relay	Controls	Safety	Sensors	Pumps/ Motors	Hub	Heaters / Coolers	Yaw System	Tower / Foundation	Power Supply / Converter	Service Items	Transformer
Major Replacement	0.001	0.001	0.095	0.154	0.001	0.000	0.002	0.002	0.001	0.000	0.000	0.000	0.001	0.000	0.001	0.000	0.005	0.000	0.001
Major Repair	0.179	0.042	0.321	0.038	0.010	0.006	0.016	0.054	0.054	0.004	0.070	0.043	0.038	0.007	0.006	0.089	0.081	0.001	0.003
Minor Repair	0.824	0.812	0.485	0.395	0.456	0.407	0.358	0.326	0.355	0.373	0.247	0.278	0.182	0.190	0.162	0.092	0.076	0.108	0.052
No Cost Data	0.072	0.150	0.098	0.046	0.053	0.058	0.059	0.048	0.018	0.015	0.029	0.025	0.014	0.016	0.020	0.004	0.018	0.016	0.009

Figure 7.2. Failure rate and category for turbine sub-systems [19].

bines with availabilities on the order of 97% [22].

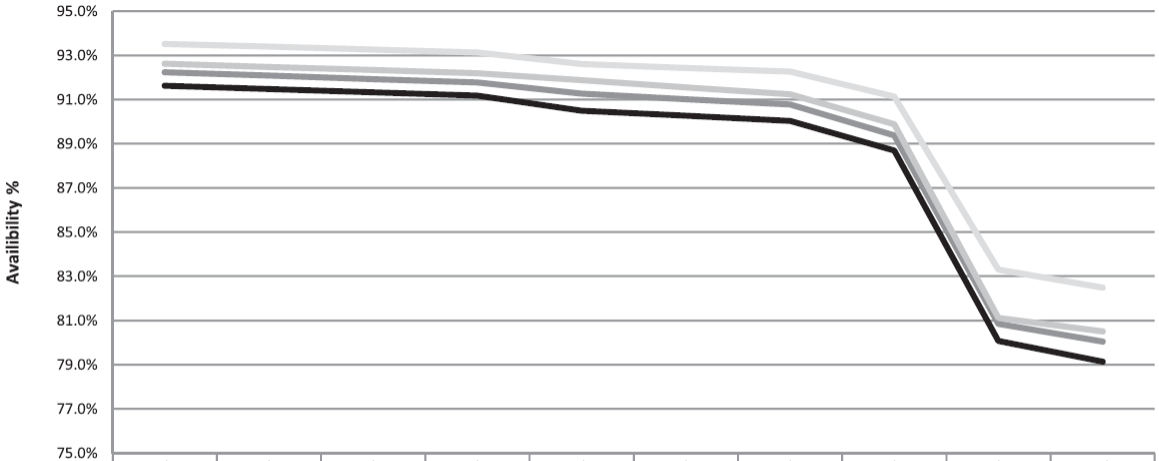
To understand the effect of wind turbine availability on LCOE, Equation 7.3 calculates the change in LCOE due to availability. The downtime costs are a percentage of the total LCOE which is approximately represented by the downtime percentage. The O&M downtime losses scale with LCOE while the direct O&M costs do not, meaning the direct costs represent a larger percentage of the LCOE for a mature industry.

$$\Delta LCOE_{availability} = LCOE_{100\%} - LCOE_{Av\%} \tag{7.1}$$

$$\Delta LCOE_{Av.} = \left(\frac{CapEx \times FCR + OpEx}{AEP}\right)_{100\%} - \left(\frac{CapEx \times FCR + OpEx}{AEP \times av.}\right)_{Av.\%} \tag{7.2}$$

$$\Delta LCOE_{Av.} = LCOE_{100\%} \times \left(1 - \frac{1}{av.}\right) \tag{7.3}$$

The direct O&M costs include the repair costs in addition to vessel transport costs. Dalgic [23] implemented an O&M model that includes a full set of climatic conditions to account for offshore access, in addition to a thorough consideration of the transportation systems available. Wind turbine subsystem failure rates are determined from historical operational data and from expert judgment and input into the model, with associated repair costs and performance implications.



	10km	20km	30km	40km	50km	60km	70km	80km	90km	100km
DFIG PRC	91.6%	91.5%	91.3%	91.2%	90.5%	90.3%	90.0%	88.7%	80.1%	79.1%
3S PMG FRC	92.2%	92.1%	91.9%	91.8%	91.3%	91.0%	90.8%	89.4%	80.8%	80.0%
2S PMG FRC	92.6%	92.5%	92.3%	92.2%	91.9%	91.6%	91.2%	89.9%	81.1%	80.5%
DD PMG FRC	93.5%	93.4%	93.3%	93.1%	92.6%	92.4%	92.3%	91.1%	83.3%	82.5%

Figure 7.3. Wind turbine availability for different drivetrain types and distance from shore [20].

Table 7.1. Operations and maintenance downtime costs (*av.* = 94.2%).

LCOE [USD/MWh]	O&M downtime losses [USD/MWh]
100	6.2
150	9.2
200	12.3

The model is performed for a hypothetical offshore wind plant located 45 km offshore using actual meteorological tower data to simulate weather windows, performed using Monte Carlo simulations. From these sets of simulations, Dalgic identified the contribution to the combined O&M costs as 67% direct O&M costs and 33% from lost revenue, Figure 7.4. Of the direct O&M costs, approximately 57% are from transport costs (38% of the combined O&M costs). The actual repair costs (staff and OEM equipment) represent only 16% of the combined O&M costs from this analysis.

Dalgic described two types of vessels, those for minor maintenance and those for major maintenance, which are shown in Figure 7.5. Offshore access vehicles (OAV) are used for technician transfer and house a crane to transfer components from the deck to the turbine's lower platform. The most expensive O&M transportation charters are jack-up vessels used to reach hub height on horizontal-axis wind turbines. The jack-up vessels account for approximately 60% of the total transport costs, despite their limited usage. In addition to the high cost of charters, these vessels

also have significant delays resulting in additional downtime losses for critical repairs. An additional limitation on these systems is that existing jack-up vessels are only capable of working in water depths less than approximately 200 m.

The identified tension-leg platform has an advantage here where it may not require jack-up vessels when combined with the platform-level height of the mechanical components of the VAWT, due to the minimal pitch and roll motions. This potential benefit of TLP and VAWT pair could account for as much as approximately a 50% reduction in transport costs, equating to an additional 19% reduction in combined O&M costs for a VAWT, per Dalgics findings. The improvement in downtime losses from not requiring the mobilization delays associated with jack-up vessels would further reduce the combined O&M costs for the floating VAWT system.

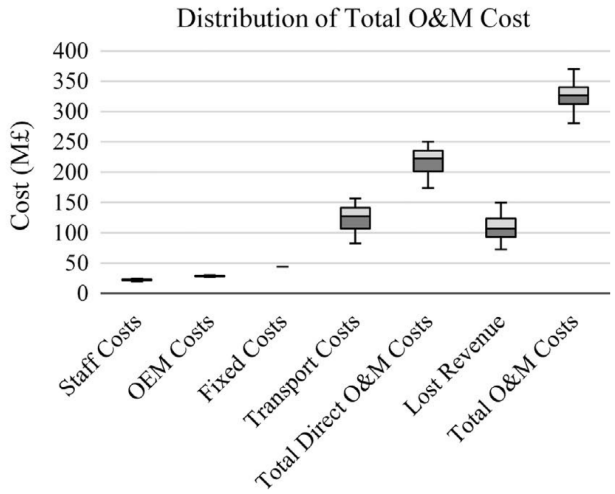


Figure 7.4. Wind plant distribution of combined operations and maintenance costs [23].

The Dalgic analysis results are used to produce the direct O&M costs used in this analysis of 22 pounds/MWh (2015), or $32/MWh. The absence of the pitch and yaw systems is used to reduce this cost by 13.9% as described previously, making the direct O&M cost $27.6/MWh. Applying this reduction to the direct O&M costs is treated as appropriate since these hub-level systems (for HAWTs) may realistically require the use of jack-up vessels at times, which is a significant contributor to the direct O&M costs. For sites up to 50 km from shore, transport cost differences were seen to be small by Carroll so this number is not reduced for the 25 km site of study.

The combined O&M costs used as the baseline in this analysis include direct costs of $27.6/MWh, with an availability of 94.2% for the VAWT system. As a second reference, these values are compared to those derived by Myhr using a different O&M model and data from existing fixed-bottom offshore turbines, which produced combined O&M costs of 30 Euro/MWh from an availability of 93.6% [15]. Reducing this cost by the same 13.9% for the VAWT results in a direct O&M cost of $32.9/MWh. The references used produce similar enough values to sufficiently trust the baseline values as stated.

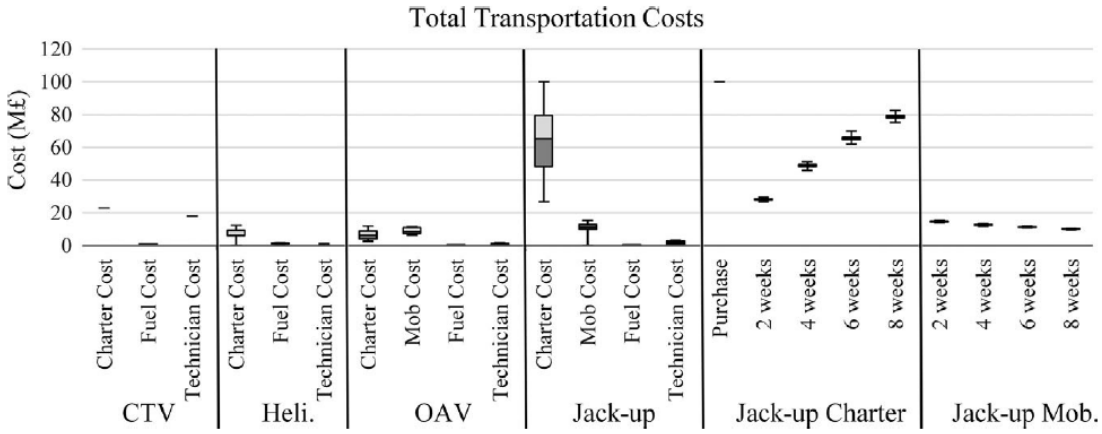


Figure 7.5. Description of operations and maintenance transportation costs by vessel type [23].

Chapter 8

Levelized cost of energy analysis

This chapter presents the LCOE analysis results using the system cost inputs described in the previous sections. The LCOE was calculated using the methodology described in Section 1, and by Equation 1.2. As a summary, the cost inputs were obtained from the sources identified in Table 8.1. The design and cost estimation for the platform, mooring, and installation represent a significant body of work performed as part of this study, with greater detail provided in Section 5 and Reference [2]. The VAWT rotor design study and optimization utilized in this study were based on findings from previous work summarized in Section 2 and Reference [1]. The remaining cost components are established within this report from literature review and using models developed by the National Renewable Energy Laboratory. The LCOE is calculated for the near-term cases using a fixed charge rate of 10.3%, while the projected future cases use a FCR of 7.9%, when noted. These rates correspond to the estimated FCR for offshore wind energy assets given the current level of project risk and that of current land-based wind energy installations, respectively, as described by NREL [24]. The justification is that as projects are successfully installed the finance rate should decrease, but realistically only to the value of current land-based installations. This is done in part to highlight the sensitivity to the fixed charge rate.

The levelized cost of energy analysis is performed for five scenarios detailed within this report:

1. Baseline LCOE
2. Upper-bound LCOE
   Projections of LCOE through design optimization and industry maturation;
3. Projected near-term LCOE
4. Projected mid-term LCOE
5. Projected longer-term LCOE

8.1 Baseline levelized cost of energy calculation

The levelized cost of energy inputs defined in this report for the baseline case are listed in Table 8.2, as described in the previous sections. This table is included to highlight the LCOE calculation inputs and methodology, which are utilized in Section 8.2 for the five LCOE study scenarios. The

Table 8.1. Summary of LCOE cost input sources.

Cost component	Source
Rotor	SNL rotor aerodynamic and structural design [1]
Generator and drivetrain components	NREL GeneratorSE [6], literature and related sources, NREL cost and scaling model [5]
Platform, mooring, and installation	Design and cost estimate performed in partnership with Stress Engineering Services [2]
Remaining balance of system capital expenditures	NREL Offshore Balance of System model [17]
Remaining financial capital expenditures	NREL Offshore Balance of System model
Operations and maintenance	Literature review

table shows the LCOE contribution from the various cost categories and the resulting baseline LCOE value for a floating offshore VAWT at the site of study (Table 1).

8.2 Levelized cost of energy analysis

The LCOE analysis is extended to explore the five study scenarios described previously. The baseline and upper-bound LCOE result from the most-likely and upper-bound platform, mooring, and installation cost estimates produced by SES, respectively. Projected costs are estimated for near, mid, and longer-term design improvements based on opportunities identified throughout this study. The projected design improvements listed in this analysis are detailed in their respective sections throughout this report.

The projected near-term LCOE estimate is viewed as the most likely value presently by taking advantage of current opportunities, such as optimization of the platform-turbine system design to remove excess design margins in operation and by improving the installation procedures to distribute vessel mobilization costs. The mid-term LCOE is determined to be a realistic estimate based on the stated accuracy of the platform, mooring, and installation cost estimates by SES through further design and operational optimization. The longer-term LCOE is a projection of cost-reduction through an advanced high energy capture rotor design. These five study scenarios and design changes are described in the following text and in Table 8.3.

Baseline LCOE; The baseline case describes the LCOE when using the most-likely values for the platform, mooring, and installation costs from the SES estimates as defined in Table 5.4. This case produces an LCOE value of $274/MWh.

Upper-bound LCOE; The upper-bound case displays the highest value for LCOE when using the upper-bound platform, installation, and mooring estimates from SES. As described in Section 5.2, these values are not considered to be the most likely cost estimates through understanding

Table 8.2. Baseline LCOE inputs and calculation (FCR = 10.3%).

Annual Energy Production		
Baseline Electrical AEP	20088	MWh
System Wake Losses	95.0%	
O&M availability	94.2%	
AEP improvements	0.0%	
Actual AEP (1 turbine):	17977	MWh
Turbine Capital Expenditures		
Rotor	8.42	MM USD
Drivetrain	2.97	MM USD
Platform	18.09	MM USD
Mooring	2.18	MM USD
Total Turbine CapEx:	31.66	MM USD
LCOE contribution:	181.40	$/MWh
Balance of System Capital Expenses (per turbine)		
Development	0.831	MM USD
Engineering and Management	0.000	
Port and Staging	0.036	MM USD
Electrical Infrastructure	2.797	MM USD
Assembly and Installation Total:	6.280	MM USD
-- SES A&I estimate	5.230	MM USD
-- Electrical Installation	1.050	MM USD
Plant Commissioning	0.000	
Total BOS CapEx:	9.94	MM USD
LCOE contribution:	56.97	$/MWh
Financial Cost Capital Expenses		
Finance Costs	1.314	MM USD
Total Finance CapEx:	1.314	MM USD
LCOE contribution:	7.53	$/MWh
Operational Expenses		
Direct O&M Costs	27.9	$/MWh
O&M availability	94.2%	
LCOE calculations		
	MM USD	$/MWh
Turbine CapEx	31.66	181.400
Balance of System CapEx	9.94	56.967
Financial CapEx	1.31	7.529
Operations and Maintenance OpEx	0.50	27.900
Total LCOE:		273.80

of the SES methodology and cost data. This case is analyzed as a reference of the highest cost scenario from the cost estimates provided, with a resulting LCOE of $323/MWh.

Projected near-term LCOE; The near-term case represents the most probable current LCOE. This case changes the baseline costs through identified improvements through optimization of the platform-turbine system and improved installation procedures, as described in Table 5.5. Rotor costs are reduced through the appropriate usage of material and composite forms that represent industry trends and reduce design margins in non-structural material sections. This case also utilizes the advanced turbine controls which provided a 16.1% improvement in annual energy production as shown in Figure 4.2. This current projection of LCOE has a value of $213/MWh.

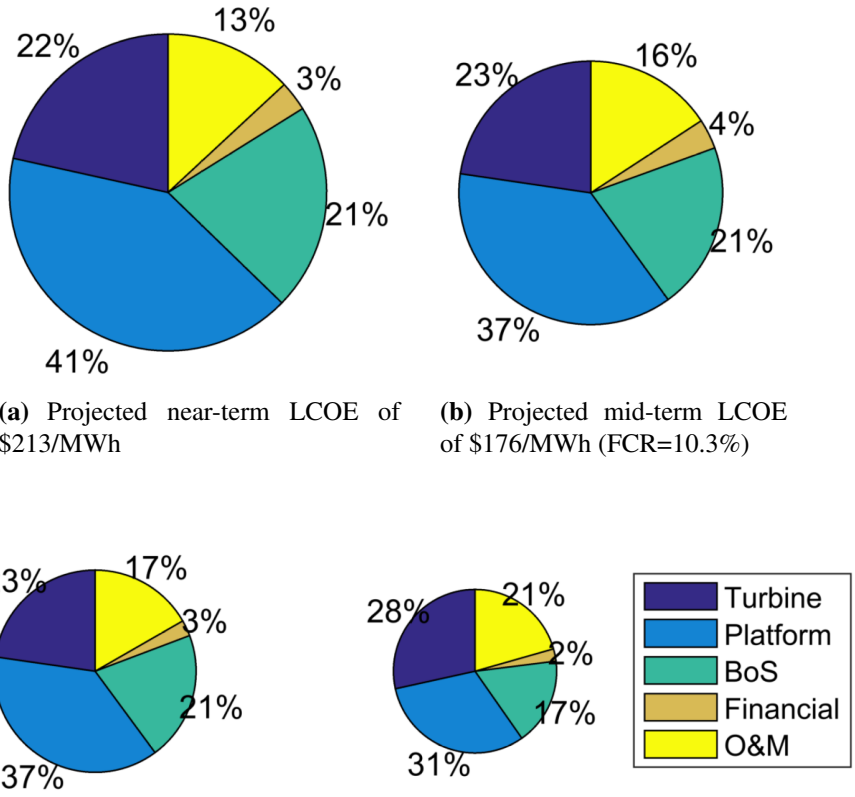
Projected mid-term LCOE; The mid-term case utilizes a combination of cost improvements projected in this report. Platform, mooring, and installation costs are described by the mid-term optimization values which reduced the SES estimates by their stated accuracy at this early stage of design, described in Table 5.5. The substructure and installation cost reductions might be realized through further reduction in the design margins and redundancy of the systems, through more representative cost estimates than the single-production volume, historical data from the oil and gas industry, and/or through optimization of the hull cellular layout. Rotor cost reductions are projected through low-cost carbon fiber material development that represents current research and projections, as described in Section 2.2.3. Operations and maintenance costs are reduced by 19% which represents the scenario where the jack-up vessel is not required, or required much less, for the more stationary tension-leg platform and platform-level VAWT drivetrain components. At this future stage of development, it is possible that the finance rates will be more favorable so the LCOE is calculated using the anticipated bounds of the FCR. The LCOE mid-term projection has a value of $176/MWh, which reduces to $135/MWh when considering a fixed charge rate representative of a more mature offshore wind energy industry.

Projected longer-term LCOE; The longer-term case describes the mature system costs from the mid-term projection, and explores the scenario where the rotor is designed for high energy capture. This scenario represents a rotor design which produces a wind plant capacity factor of 70%. At the 10.1 m/s average wind speed site of study this assumption is achievable through a 47% increase in AEP. This AEP increase is enabled through a rotor area increase calculated from scaling laws for this scenario and requires an estimated 78.2% increase in rotor cost. The assumption that corresponds to this AEP increase is that loads are managed such that the platform costs are not increased, which can be performed through control strategies that offer loads management at the higher wind speeds. For a mature offshore wind energy industry with a fixed charge rate of 7.9%, this longer-term projection produces an LCOE value of $110/MWh.

Table 8.3. LCOE study scenarios and design improvements.

	Baseline LCOE	Upper-bound LCOE	Projected near-term LCOE	Project mid-term LCOE	Projected longer-term LCOE
AEP	Baseline	Baseline	16.1% increase from advanced controls	Advanced controls	47% increase in energy capture
Rotor costs	Baseline	Baseline	Rotor material optimization	Reduction from low-cost carbon fiber	78.2% increase in rotor cost
Platform and mooring	Most-likely value	Upper-bound estimate	13.6% reduction for optimal system platform	25% reduction for mid-term optimization	Mid-term optimization
Installation	Most-likely value	Upper-bound estimate	15.3% reduction for the improved installation procedure	25% reduction for mid-term optimization	Mid-term optimization
O&M direct costs	Baseline	Baseline	Baseline	19% reduction by eliminating jack-up vessel charters	Elimination of jack-up vessel charters
Levelized cost of energy (USD/MWh)	**274**	**323**	**213**	**176** (FCR=10.3%) **135** (FCR=7.9%)	**110** (FCR=7.9%)

The LCOE estimates for the projected cases are shown with a breakdown of the major cost components in Figure 8.1. These four cases span the most-likely present value to the furthest projection when designing a high energy capture rotor. Utilizing the technology advancements described in Table 8.3, the figures show how the costs are expected to be redistributed as the industry matures. Moving to a more expensive, high energy capture rotor results in the rotor costs nearly equaling the platform costs (given the previously stated assumptions). Additionally, the direct O&M costs shown in the pie charts represent a larger portion of the LCOE as the industry matures and LCOE is reduced. Balance of system costs are reduced in the longer-term projection case due to the more expensive rotor that has higher annual energy production.



(a) Projected near-term LCOE of $213/MWh

(b) Projected mid-term LCOE of $176/MWh (FCR=10.3%)

(c) Projected mid-term LCOE of $135/MWh (FCR=7.9%)

(d) Projected longer-term LCOE of $110/MWh

Figure 8.1. Levelized cost of energy distribution for the projected cases (diameter is proportional to LCOE).

Chapter 9

Summary of Vertical-Axis Wind Turbine Benefits and Challenges

An offshore wind plant consisting of floating vertical-axis wind turbines has been designed with cost estimates performed resulting in the levelized cost of energy values previously reported. Beyond the cost estimates and LCOE values, there are additional considerations for offshore wind energy which affect projected reliability and performance which vary between HAWTs and VAWTs. This section is used as a summary of some of the major findings and interesting benefits and challenges of a VAWT system for floating offshore wind energy generation, compared to HAWTs.

Vertical-axis wind turbine rotor (blades and tower) system:

- The Darrieus VAWT design architecture was determined to be optimal from a material cost standpoint and its ability to reduce LCOE
  - The supported blade ends carry loads axially as opposed to cantilevered VAWTs and all HAWT designs which carry loads through very high bending moments
- VAWTs see periodic loading from rotational variation in angle of attack, however, they remove the gravity one-per-revolution loads that can dominate HAWT designs which become a fatigue issue in edgewise bending for massive HAWT blades
- The insensitivity to wind direction eliminates the need for yaw control, removing this failure source and improving power capture when the wind direction changes
  - VAWTs immediately respond to changing wind direction while HAWT yaw systems respond very slowly which sacrifices power and can increase loads
- The absence of pitch control requires large brakes and/or generator torque control during cut-out conditions, but which has the benefit of not requiring the massive and costly pitch bearings and removing the active control failure mechanism
- Due to their vertical rotation, VAWT rotors can be designed for optimal operation in the common wind shear conditions which can only be accomplished with HAWTs when using active systems or bend-twist coupling
- Wind veer is handled naturally for the same reason wind direction changes do not affect the performance
- Structural dynamics are more challenging for VAWTs than HAWTs due to the more closely spaced modes

  - The floating offshore application improves the structural dynamics by increasing the tower resonance modal frequencies further away from the wave excitation spectrum [25]
- Variable torque and thrust loads produce a challenge, which can be partially mitigated through blade number and torque controls
  - The variable operational loads did not ultimately drive the platform design, despite adding to the mooring requirements
  - As a result of the periodic loading for VAWTs, advanced controls can be used to increase power capture

Drivetrain:

- The massive generator, rotor bearings, and mainframe support are located 100 m or more closer to the MWL compared to a HAWT, resulting in a much lower topside center of gravity and roll/pitch mass moments of inertia, resulting in savings in mass and cost of the floating platform to meet stability requirements
  - The drivetrain is more massive than the VAWT rotor which has substantial implications for HAWT designs when mounted in the elevated nacelle, particularly as turbines get larger/taller
- The need for pitch bearings, pitch mechanisms, the yaw bearing, yaw drive, and the nacelle bedframe are eliminated reducing the mass, cost, and reliability issues of these drive systems
- All the VAWT active components are at platform-level which simplifies the installation and operations and maintenance, likely requiring smaller vessels to perform maintenance, reducing the weather restrictions and machine downtime
- Rotor thrust is carried by a bending moment in the bearings, as opposed to axial loading for a HAWT, likely resulting in larger drive bearings
- Power conversion could be met with a non-traditional generator design when utilizing the variable torque demand and advanced controls
- The periodic nature of the VAWT torque needs to be investigated for implications on the drivetrain fatigue life

Energy capture:

- Large VAWTs can have higher efficiencies than HAWTs due to the effective double passage of the rotor through the flow field and the ability to operate at higher tip speed ratios than small diameter VAWTs [14]
- Wind plant wake effects are likely smaller for VAWTs than HAWTs due to the increased turbulence generated in the wake which correlates to a faster wake recovery; further study is required
- An advanced control strategy produced a 16.1% increase in annual energy production while maintaining the ultimate platform overturning moment

Platform design and selection:

- A tension-leg platform was identified in partnership with Stress Engineering Services as the lowest cost platform architecture, with some interesting performance benefits
- The small platform motions reduce inertial loading on rotor tower and blades which become significant for massive rotors associated with offshore wind turbines
- The small platform motions additionally minimize wind turbine power loss
- The small mooring footprint of the platform simplifies installation and geotechnical survey processes, and when installed reduces impact on local fishing industries
- The platform's shallow draft improves the port accessibility requirements compared to semi-submersible and spar platform designs, enabled by the low center of gravity and roll/pitch moments of inertia of the VAWT rotor and drivetrain
- The platform is stable during all ranges of operation without requiring additional active motion controls
- Tow-out stability during ballasting drove the platform design
  - The tension-leg platform would have to be substantially larger to be stable during tow-out with a HAWT turbine installed; further study is required

Additional Capital Expenditures:

- Reduced wake effects could enable more closely spaced turbines resulting in less electrical infrastructure and installation costs, and, more substantially, resulting in a higher area power density for fixed lease areas
- The current high finance rates represent a significant contributor to the system LCOE

Operations and Maintenance:

- The removal of active pitch and yaw drive components likely results in a reliability improvement over VAWTs, saving direct O&M costs and reducing turbine downtime
- For the combination of the VAWT platform-level drivetrain and electronics and the small motion tension-leg platform, it is conceivable that the need for expensive jack-up vessel charters for common repairs would be eliminated
  - For major rotor repairs (HAWT or VAWT) on floating platforms it is accepted that the most cost-effective method would likely be to tow the entire system back to port

Scaling discussion:

- Benefits of lower topside center of gravity and mass moments of inertia for a VAWT will be further exaggerated for 10-20 MW rotors due to the massive generators at increasing distance from the mean water level for HAWTs

- Cantilevered HAWT designs will likely reach limits and challenges due to dynamic instabilities, such as flutter, before Darrieus VAWT designs due to their supported ends
- Multiple VAWTs could be mounted on a single platform due to their ability to handle turbulence and wind direction changes naturally through the vertical rotation compared to HAWTs, with a lower increase in loads compared to HAWTs; further study is required

Conclusion

A levelized cost of energy analysis has been performed for an offshore wind plant consisting of vertical-axis wind turbines on floating platforms. This analysis has been performed for a representative site off the coast of the U.S. northeast with a water depth of 150 m. VAWTs have some obvious benefits over HAWTs at the floating, offshore sites which motivated this study. The lower center of gravity reduces topside mass moments of inertia and resulting platform costs, while the platform-level placement of drivetrain components and elimination of yaw and pitch systems likely reduces operations and maintenance costs. For large, multi-megawatt VAWTs there is improved aerodynamic performance over what has been seen historically for smaller machines, which can produce higher efficiencies than HAWTs at design conditions. Advancements in composite materials over the past thirty years will also improve the VAWT fatigue characteristics over the predecessors which had jointed, aluminum blades.

Previous design studies at Sandia identified the Darrieus VAWT as the optimal rotor architecture with the greatest potential to reduce LCOE. This selection was utilized by this analysis, and results from the design's ability to carry loads mostly axially due to the supported ends, reducing the resulting material cost and weight. Different generator options were designed for the two-bladed Darrieus rotor and a medium efficiency design was selected for its optimal balance of efficiency and mass/cost.

A significant body of work is represented in the platform selection and design summarized within this report, performed in partnership with Stress Engineering Services. The first phase of the platform design was to identify an optimal floating platform architecture for the Sandia VAWT. This was done using first principles analyses with proprietary cost data from the oil and gas industry for six floating platforms identified as the most promising technologies. These platforms span the range of stability mechanisms available to floating systems and were compared based on cost, performance, and reliability. The three leading concepts in terms of cost were the spar, 4-column semi-submersible, and multi-cellular tension-leg platform. The multi-cellular tension-leg platform had an estimated 10% lower cost than these other platforms, due primarily to shorter mooring cables and simplified installation. This platform was identified as the optimal platform based also on its interesting performance benefits related to the small platform motions, such as increased energy capture and reduced inertial loads on the blades and tower. This tension-leg platform also benefits from its amenability to mass production and from having a greater ability for further optimization, based on its cellular structure and lower technology readiness level than the spar and semi-submersible platforms.

A final platform design was iterated between Sandia and Stress Engineering Services where system topside loads were calculated and then the platform was redesigned which changed the platform mass and stiffness properties, iterated until convergence. The final platform capital cost for the baseline case was $20MM, or $4MM/MW. It would be incorrect to attempt to draw relative

conclusions by comparing this platform cost with other studies, which have used different cost data. There is likely a higher level of conservatism in the platform cost estimate from this study due to the cost data's origin from one-of-a-kind floating platforms from the oil and gas industry, which are much more complex structures designed for human occupancy. Efforts were taken to remove undue conservatism during the design, but it is likely inherent to the cost data source. The design margin and room for further optimization in the design and manufacturing are instead accounted for by the LCOE projections.

The remaining capital costs and operational expenses were calculated using cost data and literature from existing offshore wind plants in Europe to add fidelity to this analysis. Where appropriate, realistic assumptions were applied to convert the HAWT data to this study. The differences were mostly applied in the operations and maintenance projections. The removal of the active pitch and yaw drive systems reduces operations and maintenance downtime losses and direct costs by an estimated 13.9% over HAWTs, further improving power availability. The platform-level placement of all the drive and electrical components combined with the small motion of the tension-leg platform make it conceivable that jack-up vessel charters could be removed from the direct operations and maintenance costs, which further reduces this operational expense by an estimated 19%. Based on this analysis the VAWT system has a 25% reduction in the combined operations and maintenance costs over a HAWT system with pitch and yaw systems.

The VAWT wind plant's levelized cost of energy was calculated based on the cost components defined within this report, including projections which capitalize on design optimization and anticipated advancements. The most likely present value for the LCOE is $213/MWh which incorporates advanced controls and rotor material optimization into the baseline configuration. Using this same system, the LCOE decreases to $176/MWh when considering further platform optimization, advanced materials, and additional operations and maintenance reductions. For a mature industry that could achieve a fixed charge rate equal to that of current land-based wind energy installations the LCOE drops to $135/MWh, revealing the sensitivity to finance rates. Finally, as a future scenario, the effect of a high energy capture rotor on the system LCOE is estimated through growing the rotor to achieve a 70% capacity factor at this site. Due to the increase in rotor cost, this larger rotor had a smaller effect than expected on the LCOE, reducing the value to $110/MWh.

The relative cost contributions to the near-term LCOE estimate are approximately 20% from turbine and drivetrain costs, 40% from the platform costs, 20% for balance of system, and 13% for direct operations and maintenance costs. Direct operations and maintenance costs become an increasingly significant portion of the LCOE since they depend on parts, labor, and vessel charters which have essentially a fixed cost relative to the system LCOE. For the longer-term projection, the direct operations and maintenance costs represent 20% of the total with an additional 6% from downtime losses. This means that a perfectly reliable turbine would have a 26% lower LCOE, making this a significant component to the cost, particularly for a mature industry.

Technology breakthrough will be important for significant development of floating, offshore wind energy in the United States. The vertical-axis wind turbine has been studied as an option with potential to reduce the cost of energy which deviates from the horizontal-axis wind turbines which have worked so well on land. Further study is merited to perform a direct comparison including HAWT and VAWT advantages and disadvantages, with cost estimates using the same

source data, and for 10-20 MW wind turbines to capture the gained efficiencies in platform costs for larger floating wind turbines.

This page intentionally left blank.

References

[1] Griffith, D. T., Barone, M., Paquette, J., Owens, B., Bull, D., Simao-Ferriera, C., Goupee, A. and Fowler, M., "*Design Studies for Deep-Water Floating Offshore Vertical-Axis Wind Turbines*," Tech. Rep. SAND2018-7002, Sandia National Laboratories, 2018.

[2] Searcy, C., Perryman, S., Maniar, D., Griffith, D. T. and Ennis, B. L., "*Optimal Floating Vertical-Axis Wind Turbine Platform Identification, Design, and Cost Estimation*," Tech. Rep. SAND2018-9085, Sandia National Laboratories, 2018.

[3] Griffith, D. T. and Johanns, W., "*Large Blade Manufacturing Cost Studies Using the Sandia Blade Manufacturing Cost Tool and Sandia 100-meter Blades*," Tech. Rep. SAND2013-2734, Sandia National Laboratories, 2013.

[4] Johanns, W. and Griffith, D. T., "*User Manual for Sandia Blade Manufacturing Cost Tool: Version 1.0*," Tech. Rep. SAND2013-2733, Sandia National Laboratories, 2013.

[5] Fingersh, L., Hand, M. and Laxson, A., "*Wind Turbine Design Cost and Scaling Model*," Tech. Rep. NREL/TP-500-40566, National Renewable Energy Laboratory, 2006.

[6] Sethuraman, L., Dykes, K., "*GeneratorSE: A Sizing Tool for Variable-Speed Wind Turbine Generators*," Tech. Rep. NREL/TP-5000-66462, National Renewable Energy Laboratory, 2017.

[7] Paulsen, U. S., Borg, M., Seabra, L., Verelst, D., Madsen, H. A., Pederson, T. F., Nielson, P. H., Schloer, S., Smadja, C., Hattel, J., Carstensen, S., Kragh, K., Baran, I., van Bussel, G., Fereira, C., Ritchie, E., Leban, K., Svendson, H., Svenstrup, O., Berthelson, P. A., de Ridder, E.-J., Battisti, L., He, W. and Veers, P., "*Evaluation of the DeepWind concept*," Research Rep. DeepWind/D8.4, Technical University of Denmark, 2014.

[8] Li, H., Chen, Z. and Polinder, H., "*Models for Numerical Evaluation of Variable Speed Different Wind Generator Systems*," Research Rep. UpWind/D1B2.b.2, Delft University of Technology, 2007.

[9] Fullenkamp, P. H. and Holody, D. S., "US Wind Energy Manufacturing and Supply Chain," *Global Wind Network*, 2014.

[10] Website, *http://steelbenchmarker.com/files/history.pdf*, accessed June 14, 2017.

[11] Murray, J. C. and Barone, M., "The Development of CACTUS, a Wind and Marine Turbine Performance Simulation Code," *AIAA 49th Aerospace Sciences Meeting*, Vol. 147, 2011.

[12] *IEC 61400-1 Ed.3: Wind turbines - Part 1: Design Requirements*, International Electrotechnical Commission, 2005.

[13] Martin, S. B., Westergaard, C. H., White, J. R. and Karlson, B., "*Visualizing Wind Farm Wakes Using SCADA Data*," Tech. Rep. SAND2016-4484, Sandia National Laboratories, 2016.

[14] Ferriera, C. S., Madsen, H. A., Barone, M., Roscher, B., Deglaire, P. and Arduin I., "Comparison of aerodynamic models for Vertical Axis Wind Turbines," *Journal of Physics: Conference Series*, Vol 524, 2014.

[15] Myhr, A., Bjerkseter, C., Agotnes, A. and Nygaard, T. A., "Levelised cost of energy for offshore floating wind turbines in a life cycle perspective," *Renewable Energy*, Vol. 66, 2014, pp. 714-728.

[16] The Crown Estate, "*UK Market Potential and Technology Assessment for Floating Offshore Wind Power*," 2012.

[17] Maness, M., Maples, B. and Smith, A., "*NREL Offshore Balance-of-System Model*," Tech. Rep. NREL/TP-6A20-66874, National Renewable Energy Laboratory, 2017.

[18] Dinwoodie, I., McMillan, D., Revie, M., Lazakis, I. and Dalgic, Y., "Development of a Combined Operational and Strategic Decision Support Model for Offshore Wind," *Energy Procedia*, Vol. 35, 2013, pp. 157-166.

[19] Carroll, J., McDonald, A. and McMillan, D., "Failure rate, repair time and unscheduled O&M cost analysis of offshore wind turbines," *Wind Energy*, Vol. 19, No. 6, 2016, pp. 1107-1119.

[20] Carroll, J., McDonald, A., Dinwoodie, I., McMillan, D., Revie, M. and Lazakis, I., "Availability, operation and maintenance costs of offshore wind turbines with different drive train configurations," *Wind Energy*, Vol. 20, No. 2, 2017, pp. 361-378.

[21] *Final Publishable Summary of Results of Project ReliaWind*, ReliaWind Project No. 212 966, 2011.

[22] The Crown Estate, "*A Guide to UK Offshore Wind Operations and Maintenance*," 2013.

[23] Dalgic, Y., Lazakis, I., Dinwoodie, I., McMillan, D. and Revie, M., "Advanced logistics planning for offshore wind farm operation and maintenance activities," *Ocean Engineering*, Vol. 101, 2015, pp. 211-226.

[24] Stehly, T., Heimiller, D. and Scott, G., "*2016 Cost of Wind Energy Review*," Tech. Rep. NREL/TP-6A20-70363, National Renewable Energy Laboratory, 2017.

[25] Owens, B. C., Griffith, D. T. and Hurtado, J. E., "Modal Dynamics and Stability of Large Multi-megawatt Deepwater Offshore Vertical-axis Wind Turbines: Initial Support Structure and Rotor Design Impact Studies," *32nd ASME Wind Energy Symposium*, National Harbor, MD, January 13-17, 2014.

DISTRIBUTION:

1 MS 0899 Technical Library, 9536 (electronic copy)

This page intentionally left blank.



Sandia National Laboratories