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Technical Report
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Foreword: The Path to U.S. Offshore Wind

After a decade of rising costs and technical challenges, project financial data indicates that offshore wind may finally be on a downward cost trajectory while the industry logged its best deployment year ever in 2015. Historically, rising offshore wind costs have been attributed to a myriad of hindrances, including increasing siting challenges (e.g., deeper water, greater distances from shore) and a wide range of installation and operational difficulties that have frustrated developers and offset gains made in technology, learning, and experience. The resilience of the European offshore wind industry to overcome these daunting cost challenges can be attributed to stable European policy commitments, the introduction of new offshore-class turbine and substructure technologies, and the creation of an offshore wind industry supply chain.

The aspiring offshore wind development community in the United States has observed the positive trends in Europe with cautious optimism. In 2016, a 30-MW wind power plant off the coast of Block Island, Rhode Island will be the first U.S. offshore wind power project, marking a definitive start for the U.S. offshore wind industry. The U.S. Department of Energy's *Wind Vision* (2015) study scenario estimates that 86 GW of offshore wind could be installed in the United States by 2050 representing 7% of the Nation's electricity; and a recent report by the National Renewable Energy Laboratory (NREL) shows an abundant offshore wind resource that could support even greater levels of deployment (Musial et al. 2016). At the present nascent stage, the market drivers lean heavily on state policies and European experience. For U.S. markets to mature, a path to economic viability needs to be demonstrated.

This report is intended to shed light on the cost challenges for the U.S. offshore wind industry. Although these results are still at a preliminary stage, we have attempted to conduct the most comprehensive analysis to date quantifying the cost of offshore wind in the United States. This report addresses an extensive set of objectives and hopes to begin a conversation that ultimately reduces the uncertainty in quantifying this cost. The spatial-economic cost model developed for this study illustrates the complexity in reporting the levelized cost of energy (LCOE) for U.S. offshore wind as a single value by underscoring the importance of geospatial site variations on LCOE. The modeling approach creates cost scenarios that differentiate geospatial, technology, and market variables to quantify LCOE and future cost-reduction potential.

This study does not include a detailed comparison between European and U.S. offshore wind markets; however to achieve the needed cost reductions in the United States, this analysis assumes continued investments in technology innovation and domestic offshore wind deployment levels that are sufficient to build and sustain a domestic supply chain. While the model assumptions are based on sound engineering principals, this report is only a first step in a longer process to quantify cost reductions for offshore wind energy and to create market certainty for this fledgling clean energy technology in the United States. Further sensitivity studies, engineering and economic modeling, and stakeholder vetting are needed.

We thank the U.S. offshore wind community for your interest, and we look forward to your feedback.

–Dr. Daniel Laird,

Director of the National Wind Technology Center at NREL

Acknowledgments

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Editing was provided by Sheri Anstedt from the National Renewable Energy Laboratory.

List of Acronyms

AC	alternating current
AEP	annual energy production
BOEM	Bureau of Ocean Energy Management
BOS	balance of systems
CapEx	capital expenditures
CC	capacity credit
COD	commercial operation date
CP	capacity price
CTV	crew transfer vessel
DC	direct current
DOE	U.S. Department of Energy
ECN	Energy Research Centre of the Netherlands
EIA	Energy Information Administration
FC	Financial Close
FCR	fixed charge rate
GIS	geographic information system
Hs	significant wave height
HVAC	high-voltage alternating current
HVDC	high-voltage direct current
km	kilometer
kN	kilonewton
kn	knot
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
L	length (equations only)
LACE	levelized avoided cost of energy
LCC	line-commutated converter
LCOE	levelized cost of energy
m	meter
MACRS	Modified Accelerated Cost Recovery
MBL	minimum breaking load (equations only)
MHK	marine and hydrokinetic
mm	millimeter
MP	marginal generation price
MVDC	medium-voltage direct current
MW	megawatt
MWh	megawatt-hour
nm	nautical mile
NPV	net present value
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
OpEx	operational expenditures
ReEDS	Regional Energy Deployment System
RNA	rotor nacelle assembly

s	second
SES	surface effect ship
t	ton
TWh	terawatt-hours per year
USD	U.S. dollars
UTM	Universal Transverse Mercator
Ws	Wind speed
WSC	voltage source converter
WIS	wave information system
WISDEM	Wind-Plant Integrated System Design & Engineering Model
yr	year

Executive Summary

This report describes a comprehensive effort undertaken by the National Renewable Energy Laboratory (NREL) to understand the cost of offshore wind energy for markets in the United States. The study models the cost impacts of a range of offshore wind locational cost variables for more than 7,000 potential coastal sites in U.S. offshore wind resource areas. It also assesses the impact of more than 50 technology innovations on potential future costs for both fixed-bottom and floating wind systems. Comparing these costs to an initial site-specific assessment of local avoided generating costs, the analysis provides a framework for estimating the economic potential for offshore wind. The analysis is intended to inform a broad set of stakeholders and enable an assessment of offshore wind as part of energy development and energy portfolio planning. It provides information that federal and state agencies and planning commissions could use to inform initial strategic decisions about offshore wind developments in the United States.

The primary objective for this study is to understand whether offshore wind can achieve significant cost reductions that may allow the technology to reach economic viability during the time frame from 2015–2027 (commercial operation date, or COD).¹ This analysis defines a scenario that assumes that the U.S. offshore wind industry can leverage the recent European offshore wind technology and industry experience while accounting for some important physical, regulatory, and economic differences. The cost-reduction pathway under this scenario applies projected cost reductions developed for European projects and assumes sufficient deployment in the United States and domestic supply chain maturity to support these cost reductions during the analysis period. The analysis relies upon a newly developed geospatial cost model, analytical assumptions for potential cost-reduction pathways, and corresponding cost-of-energy estimates adjusted for location, regional resource, and time. In a final step, local offshore wind costs are compared to a preliminary assessment of avoided generating costs for an estimate of economic viability in a business-as-usual scenario.

The specific objectives of this analysis were to:

- Quantify the impact from the wide variety of spatial characteristics found throughout the U.S. offshore wind resource area on the levelized cost of energy (LCOE) and economic viability of offshore wind in the United States at specific points in time and under current technology, market, and regulatory conditions.
- Determine the cost-optimal choice between fixed-bottom and floating offshore wind technologies under various site conditions.
- Estimate the impact from technology innovation and market maturity during the time frame from 2015–2027 (COD) on LCOE.
- Provide a framework to quantify economic viability for offshore wind in the United States.

The findings from this analysis indicate that under the modeled scenario offshore wind can be expected to achieve significant cost reductions and may approach economic viability² in some

¹ All years are reported in COD, if not indicated otherwise.

² Without considering any potential impacts from policy (e.g., state renewable portfolio standards, production tax credits, carbon pollution and other greenhouse gas regulation, or loan guarantee programs); Accelerated depreciation (Modified Accelerated Cost Recovery [MACRS]) is considered.

parts of the United States within the next 15 years. In particular, some key findings from this analysis include:

- Offshore wind costs presently span an estimated range from \$130/MWh–\$450/MWh³ in 2015. This wide range in costs reflects the variation in geospatial characteristics among U.S. offshore wind site conditions.
- The NREL Offshore Wind Cost Model indicates that between 2015 and 2030, average cost reductions of approximately 5% can be achieved annually, and by 2030 offshore wind may become economically viable in some parts of the United States.
- Cost-reduction pathway modeling and analysis of future conditions show that cost ranges are reduced by 2022 to a range from \$95/MWh–\$300/MWh, and they are further reduced by 2027 to a range from \$80 MWh–\$220/MWh among U.S. coastal sites
- Innovations to reduce cost were found to benefit both fixed-bottom and floating offshore wind systems. During the time period considered, the costs of the two technologies are found to converge under the cost-reduction pathway scenarios modeled.
- Analyses using four typical substructure types show that the cost-optimal choice between fixed and floating technology changes in water depths between 45 m and 60 m.
- By comparing costs to a preliminary assessment of avoided costs, the more detailed results of the study indicate that offshore wind may approach economic viability without direct policy support in some parts of the United States within the next decade, particularly in parts of the northeastern Atlantic Ocean and in a small number of locations along the mid-Atlantic coast.
- Locations that have not been found to be economically viable in this short-term analysis without direct incentives may still have long-term potential, but this was not evaluated within the scope of this study. Changing market conditions could also create prospects for economic viability in the short- and long-term.

The data and assumptions in this analysis were derived from a combination of a wide variety of sources (see references). Primary sources include market reports (e.g., Moné et al. [2015]; Smith, Stehly, and Musial [2015]), cost-reduction pathway studies (e.g., Valpy et al. [2014]; Catapult [2015]; E.C. Harris [2012]; The Crown Estate [2012]; The Crown Estate [2015]), literature (e.g., Brown et al. [2015]; Energy Information Administration, or EIA [2013]; Milligan and Porter [2008]; Short, Packey, and Holt [1995]), spatial data layers (Table 3), government data sources (e.g., EIA; U.S. Department of Energy, or DOE [2015]), and industry collaboration. This analysis focused on assessing the relative LCOE and levelized avoided cost of energy (LACE) impact of changes in spatial variables across the U.S. resource area. The analysis does not aim to precisely estimate costs or avoided costs at any one location. The analysis was constrained by available geographic information system (GIS) data, existing model capabilities, and simplifications necessary to process data. These limitations are described in detail in later sections.

The calculation of costs and economic potential in this analysis directly corresponds to a new offshore wind resource terminology framework that was developed to more formally classify and

³ All costs are reported in U.S. dollars (USD) (2015), if not indicated otherwise.

clarify offshore wind resources relative to previous studies (Musial et al. 2016; Schwartz et al. 2010). In this new framework, shown in Figure ES-1, different classes of offshore wind resources are distinguished based on a set of criteria. These resource classes are subsets of one another, starting from total resource potential, which captures the entire set of resources (recoverable and unrecoverable); to gross, technical, and economic resource potential; and, finally, deployment. This analysis seeks to improve the understanding of the economic potential of offshore wind as a subset of the technical resource potential shown in Figure ES-1. Technical resource potential is represented by the oceans and Great Lakes areas of the United States where currently available offshore wind technology has been proven to be technically feasible. The technical resource area is further reduced to exclude major land-/ocean-use and environmental siting conflicts. Exclusions were also made to limit water depths to less than 1,000 m and wind speeds to greater than 7 m/s (at hub heights of 100 m). For the Great Lakes, water depths were limited to 60 m or below because floating foundations are required at water depths greater than 60 m, and technology that would allow floating foundations to reliably survive in freshwater ice does not currently exist.

From Musial (2016), the technical resource potential of the United States was determined to be 2,058 GW of capacity or 7,203 TWh/year. This technical resource potential provides a quantity of developable offshore wind resource that is approximately twice the electric energy consumption of the United States in 2015 (Musial et al. 2016).

The economic potential is a subset of this technical resource potential, as shown in Figure ES-1. Until this analysis, the economic potential for offshore wind in the United States had not been assessed previously, but the methodology has been documented and applied for other technologies, including solar photovoltaics and land-based wind (Brown et al. 2015; Lopez et al. 2012; DOE 2013). Following this established methodology, economic potential is defined as the subset of the available technical resource potential for which the cost required to generate electricity (which determines the minimum revenue requirements to develop the resource) is below the revenue available from displaced energy and displaced capacity.

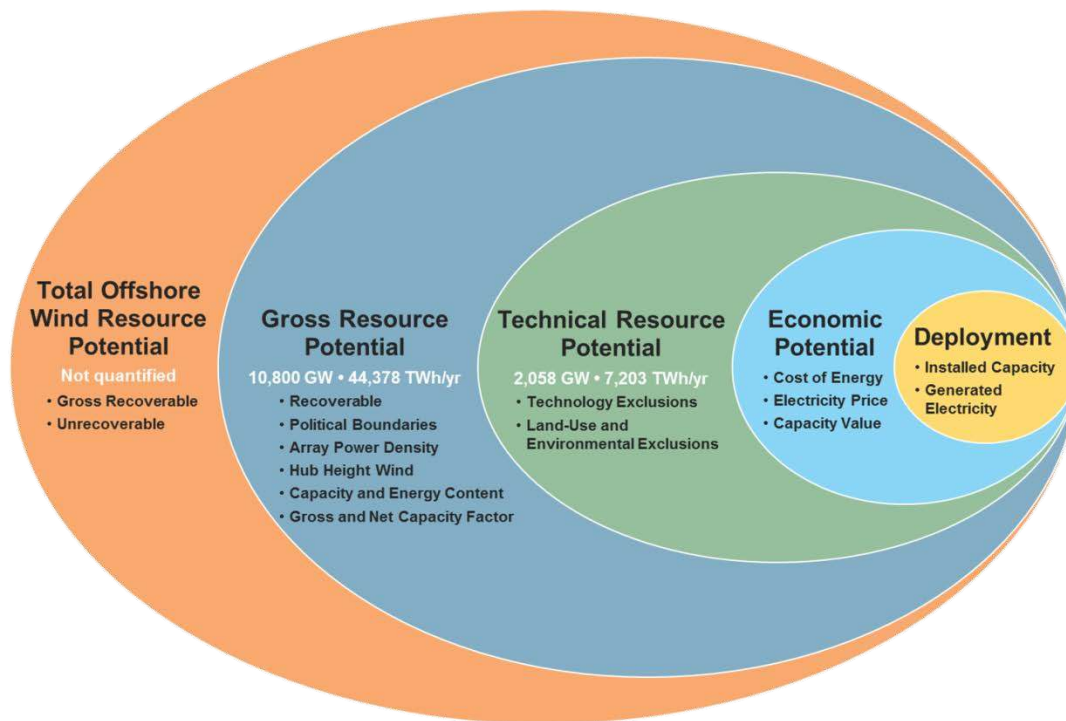


Figure ES-1. U.S. offshore wind resource terminology framework indicating estimated resource potential and classification criteria. Image adapted from Musial et al. (2016)

This necessary condition for economic potential can be stated in terms of “net value” as shown in Eq. ES-1:

$$\text{Net value (\$/MWh)} = \text{LACE} - \text{LCOE} \quad (\text{Eq. ES-1})$$

Economic potential, expressed in capacity (e.g., GW) or generation (e.g., TWh/year), is the quantity of the technical resource potential associated with locations that have a net value greater than zero, indicating economic viability. LACE is a measure of the potential revenue from wholesale electricity prices and capacity that is available to a new generator absent other revenue streams such as tax credits or renewable energy credits (EIA 2015b). The metric varies regionally and by technology (EIA 2015b); therefore, economic potential depends on locations where low LCOE and relatively high LACE coincide.

Leveraging the European Cost-Reduction Experience

Cost reduction is a key requirement for long-term growth of the offshore wind industry. In 2011, the *National Offshore Wind Strategy* (DOE 2011) focused on developing cost-reduction strategies as one of its primary goals, and this emphasis continues to be the critical driver for the industry. Global progress in technology innovation, deployment, and experience with maturing European offshore wind supply chains are assumed in this study to be leveraged by the first U.S. offshore wind power projects; however, the model also takes into account some (but not all) key differences between European and U.S. markets, including currency exchange rates, existing infrastructure, some supply chain maturity considerations, vessel availability and regulation (e.g., Jones Act requirements), workforce readiness, and physical characteristics of the offshore wind-

siting environment. Although not modeled in this study, cost differences between U.S. and European markets could also be influenced by political considerations, including differences in regulatory structures, tax codes, and incentive programs (Smith, Stehly, and Musial 2015).

Although the first U.S. offshore wind power project will not come online for commercial operation until late 2016, in 2015 a total of 3,847 MW of new offshore wind power projects began operations globally, reaching a total of 11,370 MW by year-end (Smith, Stehly, and Musial 2015). These project developments, primarily in Europe, offer cost data that have served as the baseline for the U.S. cost projections in this report and have helped inform the cost-reduction pathway analysis. Representative groups of major European cost studies for projected years 2014–2035 are shown in Figure ES-2 (DOE 2015).

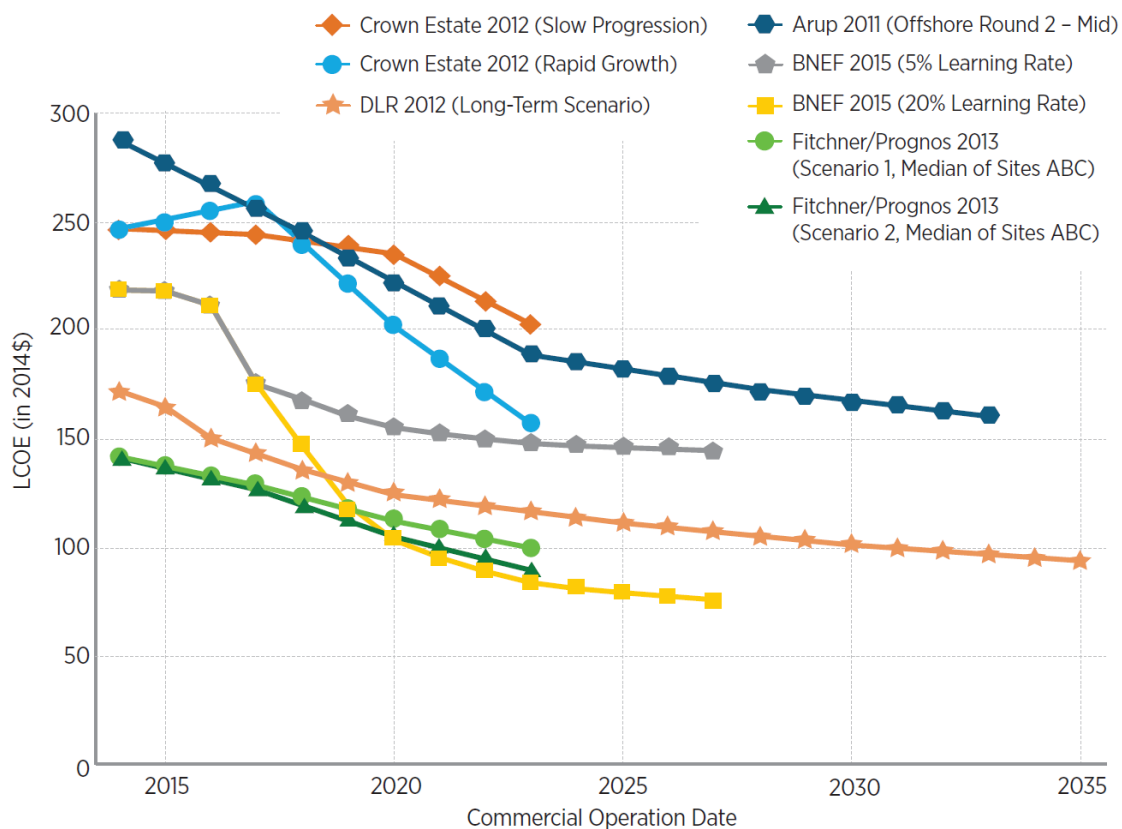


Figure ES-2. Groups of major international LCOE estimates for offshore wind (2014–2035). Data for the image obtained from *The Crown Estate* (2012), *DLR* (2012), *ARUP* (2011), *Bloomberg New Energy Finance* (2015), and *Fitchner and Prognos* (2013)

Each curve in Figure ES-2 is based on studies conducted primarily for fixed-bottom systems. These cost-reduction estimates show significant variability, but they indicate costs trending downward. Although many models do not extend to 2030, the trend from several models indicate that \$100/MWh before 2030 is achievable in Europe given continued global technology innovation (e.g., trends in increasing turbine size) in conjunction with increasing levels of deployment and continued market visibility. European project data and tender offers suggest that offshore wind costs may be approaching this cost range in the near future, as indicated by recent

winning tender offers of €81/MWh (DONG Energy, Borssele I and II)⁴ in 2016 and \$114/MWh (Vattenfall, Horns Rev III)⁵ in 2015 (both excluding transmission costs).

The spatial-economic modeling results for the entire U.S. offshore wind technical resource area⁶ (more than 7,000 individual sites) are summarized in Figure ES-3. The chart shows the modeled results for the sites in a wide range of LCOE values due to geospatial (geographically dependent) variations in wind power plant performance, capital expenditures, and operating expenses. These variations are represented in the model as geospatial cost functions related to the following parameters:

- Water depth
- Distance to shore
- Wind resource
- Wave regime
- Seabed conditions (to determine anchor type only)
- Prospective staging ports
- Possible inshore assembly areas (for floating spars)
- Existing grid features and potential connection points
- Environmentally sensitive areas
- Competitive use areas.

⁴ See <http://www.offshorewind.biz/2016/07/05/dong-energy-winner-of-dutch-borssele-i-ii-tender/>, accessed July 2016; winning tender converted from euros to USD based on 2016 exchange rates (until June 2016).

⁵ See <http://www.windpowermonthly.com/article/1397274/vattenfall-gives-horns-rev-3-go-ahead>, accessed July 2016; winning tender converted from euros to USD based on 2015 exchange rates.

⁶ For the definition of the technical resource area, see above and Section 4 for more details.

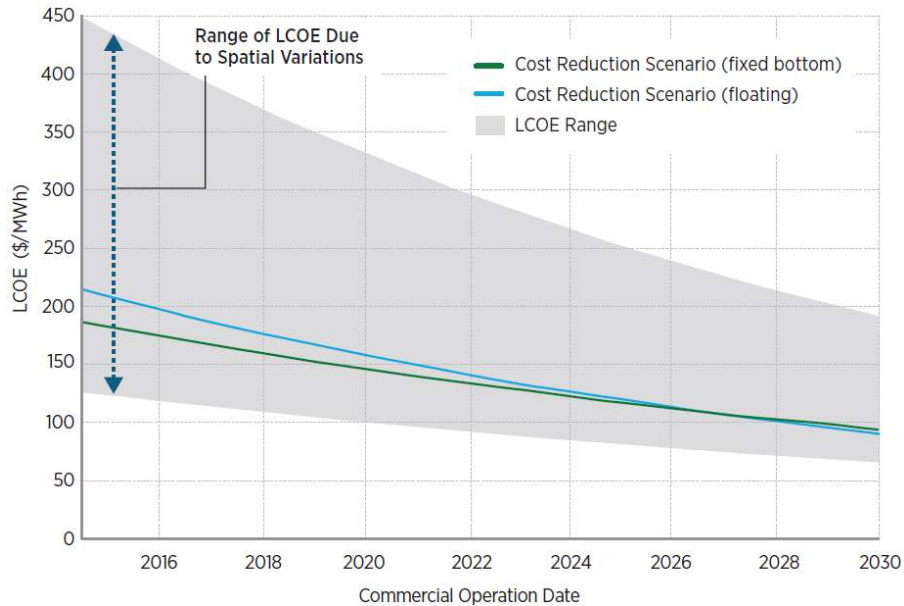


Figure ES-3. LCOE (unsubsidized⁷) for potential offshore wind power projects from 2015–2030 (COD) throughout the technical resource area

Note: Data plotted are an exponential curve fit through the modeled LCOE values (2015, 2022, and 2027 COD). The generic reference sites (“Cost Reduction Scenario”) approximate the average site conditions at the current Bureau of Ocean Energy Management (BOEM) wind energy areas along the East Coast, but they do not represent any specific site.

These geospatial variations are represented by the height of the curve as indicated by the vertical arrow in Figure ES-3. The model indicates that LCOE varies widely from one location to another at any given point in time. Based on 2015 technology assumptions, the LCOE for potential offshore wind locations ranged from \$130/MWh–\$450/MWh, reflecting the broad diversity of U.S. site conditions. It could be expected that locations at the lower end of this LCOE range are most relevant for deployment; however, outliers at the upper end of this LCOE range would likely not be considered for development. Policy or direct subsidies are not considered.

Figure ES-3 also shows potential LCOE reductions over time along the horizontal axis. The figure shows two site-specific generic reference scenarios for cost reduction that relate to typical fixed-bottom (green line) and floating sites (blue line). These generic reference sites, evaluated under the cost-reduction scenario developed in this analysis, approximate the average site conditions at the current BOEM wind energy areas along the East Coast, but they do not represent any specific site (Smith, Stehly, and Musial 2015). The model indicates that reductions in LCOE from \$185/MWh–\$93/MWh (fixed-bottom scenario) and \$214/MWh to \$89/MWh (floating scenario) during the period from 2015–2030 (COD) are feasible for these offshore wind cost-reduction scenarios (see Table ES-1).

⁷ Without considering any potential impacts from policy (e.g., state renewable portfolio standards, production tax credits, carbon pollution and other greenhouse gas regulation, or loan guarantee programs); Accelerated depreciation (MACRS) is considered.

Table ES-1. Estimated Potential LCOE Ranges for the Reference Scenarios (Fixed-Bottom and Floating) from 2015–2030 (COD)

Reference Scenario	\$/MWh			
	2015 (COD)	2022 (COD)	2027 (COD)	2030 (COD) ⁸
Fixed-Bottom	185	141	106	93
Floating	214	145	108	89

Note: Values are rounded and based on defined scenarios that assume that the U.S. offshore wind industry can leverage the recent European offshore wind technology and industry experiences. Data is modeled for the focus years 2015, 2022, and 2027 (COD), and an exponential curve fit is used for the 2030 (COD) data. The generic reference sites approximate the average site conditions at the current BOEM wind energy areas along the East Coast, but they do not represent any specific site. Policy or direct subsidies are not considered.

Table ES-2 depicts the spatial variation in estimated potential LCOE among different offshore wind regions for the focus years 2015, 2022, and 2027 (COD), respectively. In 2015 (COD), the lowest LCOE in the country ranges from approximately \$130/MWh–\$150/MWh, which can mostly be found along the coast of Massachusetts, the Great Lakes regions, and more sparsely scattered across the Eastern seaboard and Texas coast. The lowest-cost sites are characterized by annual average wind speeds ranging from 9 m/s–10 m/s (at hub heights of 100 m), with water depths less than 20 m, and located less than 50 km from shore. LCOE among U.S. coastal sites reaches a maximum of \$450/MWh for projects sited farther from shore, in deep water, and with low average winds; these are unlikely to be deployed given better site characteristics elsewhere. Between 2015–2027 (COD), LCOE decreases among all regions. By 2027 (COD), the lowest LCOE ranges from \$80/MWh–\$85/MWh, with the Pacific region and Hawaii showing a lower-bound LCOE of \$100/MWh. The high end of the LCOE estimates among regions varies from \$130/MWh in the North Atlantic to \$220/MWh in the Pacific region.

⁸ An exponential curve fit through the modeled LCOE values (2015, 2022, and 2027 [COD]) allowed for the calculation of an LCOE value for 2030 (COD).

Table ES-2. Estimated Potential LCOE Ranges among Different U.S. Coastal Regions from 2015–2027 (COD)

U.S Coastal Region	\$/MWh					
	2015 (COD)		2022 (COD)		2027 (COD)	
	Low	High	Low	High	Low	High
North Atlantic	130	270	95	180	80	130
South Atlantic	145	360	110	250	85	170
Great Lakes	130	300	95	200	80	140
Gulf Coast	140	390	110	260	80	180
Pacific	180	450	130	300	100	220
Hawaii	200	270	130	180	100	130

Note: Values are rounded and based on defined scenarios that assume that the U.S. offshore wind industry can leverage the recent European offshore wind technology and industry experiences. Policy or direct subsidies are not considered.

Recent cost studies have estimated LCOE to represent national averages or specific regions. These studies apply different methodologies and do not rely on a comprehensive spatial analysis as presented in this report. DOE’s *Wind Vision* (2015) study scenario estimates offshore wind LCOE in the range from \$170/MWh–\$269/MWh in 2013, which reduces to a range from \$83/MWh–221/MWh by 2050 under its weighted average grid connection cost scenario. Kempton, McClellan, and Ozkan et al. (2016) estimated LCOE from a pipeline of offshore wind power projects in wind energy areas in Massachusetts and determined LCOE of \$162/MWh for 2023 (COD), \$128/MWh for 2026 (COD), and \$108/MWh for 2029 (COD).

Estimating U.S. Economic Viability for Offshore Wind

LCOE alone is not sufficient to determine a site’s economic potential because it is dependent not only on costs but also on demand-side considerations, such as the system value that a new generation resource may provide to local electricity markets. Some of these demand-side factors can be approximated by LACE, which can be thought of as the potential available revenue to new generation, which may vary significantly from one U.S. coastal region to another.

For the purpose of this analysis, LACE comprises the net present value (NPV) of revenue from wholesale electricity prices and capacity value divided by the NPV of energy production. LACE is a demand-side metric because it implicitly considers the value from load, transmission constraints, and the existing mix of generation that offshore wind may replace by including the following parameters:

- Wholesale electricity prices
- Market marginal costs (system lambdas)
- Capacity credit
- Capacity payment.

Figure ES-4 illustrates how the declining offshore wind LCOE modeled in the analysis corresponds to the modeled LACE estimates from 2015–2030 (COD) for more than 7,000 sites throughout the technical resource area of the United States. As shown, LACE is generally predicted to increase gradually among U.S. coastal areas over time as a result of increased power generation and delivery costs (EIA 2015a)⁹; while this analysis predicts LCOE to decline. The modeled data show that without policy incentives the lower bound of LCOE and higher bound of LACE start to overlap near 2021 (COD), and this overlap increases over time.¹⁰ This trend indicates that after 2021 a growing number of U.S. offshore wind sites will have the potential to meet their modeled project cost requirements with available revenue from prevailing prices for electricity and capacity under a scenario not considering project-specific government-support schemes.

Figure ES-4 also illustrates the assessment of economic viability for two contrasting offshore wind locations in Massachusetts using floating technology. A set of markers (stars and dots) included for focus year 2027 (COD) show site specific LCOE and LACE estimates. The first site, indicated by dots, has a water depth of 926 m and has a distance of 264 km distance from site to cable landfall. Its LACE of \$93/MWh (green dot) compares to an LCOE of \$122/MWh (blue dot) in 2027 (COD); therefore, this location is not considered economically viable. On the other hand, the second site, indicated by stars, has a water depth of 221 m and a distance of 72 km from site to cable landfall. Its LACE of \$103/MWh (green star) compares to an LCOE of \$92/MWh (blue star) by 2027 (COD); because LACE is greater than LCOE, this location is considered to be economically viable by 2027 (COD).

⁹ Although EIA (2015a) and other sources generally predict an increase in power generation and electricity delivery costs, a range of factors may influence future electricity costs, some of which are challenging to predict. These may include (but are not limited to) future developments in energy efficiency, transportation, and storage; changes in fuel prices and generation technologies; market structures; and macroeconomic factors.

¹⁰ The area of the overlap is not a direct indication of the total quantity of sites that are economically viable because the chart does not distinguish between the geographic location of the LCOE sites and the LACE sites. The chart does, however, indicate that significant economic potential is possible. The heat maps shown in Section 8 provide a better assessment of the locations where the model predicts economic viability.

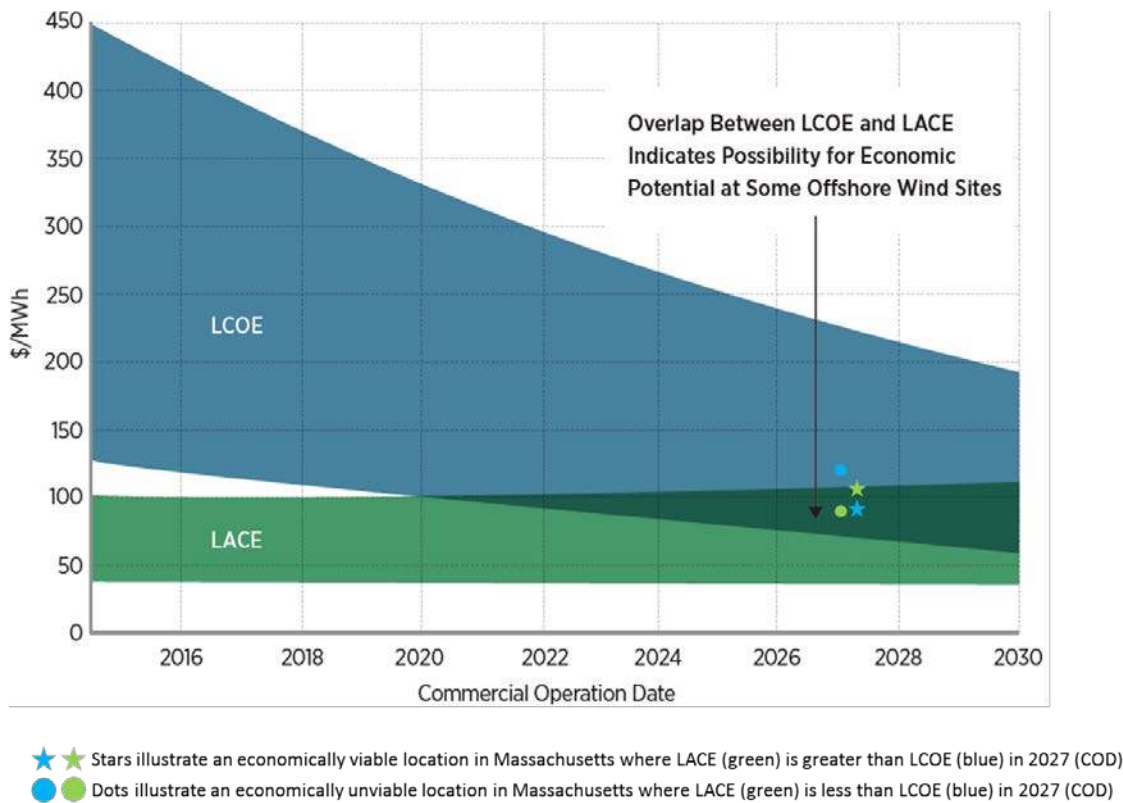


Figure ES-4. Comparison of LCOE to LACE estimates (unsubsidized¹¹) from 2015–2030 (COD)

Note: Data plotted are an exponential curve fit through the modeled LCOE and LACE values (2015, 2022, and 2027 [COD])

The comparison of LCOE to LACE in Figure ES-4 can serve as a high-level indicator of the economic potential for offshore wind in the United States within the next 15 years. In other words, offshore wind sites that achieve economic potential ($LACE > LCOE$) provide some indication that these sites may be competitive in the market for new electricity generation. Policy makers at the local, state, and federal levels may choose to establish conditions that would enable deployment by providing incentives, such as tax incentive structures, offshore wind capacity carve-outs, or feed-in tariffs. For instance, the impact of the production tax credit has been estimated to reduce wind LCOE (or, alternatively, increase LACE) by \$17/MWh (Bolinger 2014). Within the LACE/LCOE framework developed in this report, this can be thought of as reducing the LACE at a specific location by \$17/MWh, which would effectively increase the chance for economic viability at a given location.

Moreover, the analysis indicates that in the future there could be ample sites with the economic potential needed to meet growing offshore wind demand, such as the 86 GW by 2050 projected under DOE’s *Wind Vision* (2015) study scenario, although further analysis is required to demonstrate these specific deployment levels.

¹¹ Without considering any potential impacts from policy (e.g., state renewable portfolio standards, production tax credits, carbon pollution and other greenhouse gas regulation, or loan guarantee programs); Accelerated depreciation (MACRS) is considered.

The analysis findings indicate that offshore wind can be expected to achieve significant cost reductions and may become economically viable in some parts of the United States within the next 15 years in a scenario that does not consider direct policy incentives. This assessment of economic potential shows that by 2027 (COD) in some areas within the U.S. offshore technical resource area relatively low LCOE coincides with relatively high LACE levels, indicating economic potential. These offshore wind sites are located in the northeastern Atlantic Ocean and in a small number of locations along the mid-Atlantic coast.

Key Caveats and Limitations

This study is believed to be the most comprehensive analysis to date quantifying the cost of offshore wind in the United States; however, these are initial results and will be further refined as new tools and data become available. The reader should be aware of the following caveats and limitations:

- To achieve the modeled cost reductions in the United States, a key assumption is that there will be continued investments in technology innovation, developments, and the market visibility of a robust domestic supply chain commensurate with the established European offshore wind supply chains during the analysis period from 2015–2027 (COD) and sustained domestic offshore wind development (DOE 2015; Navigant 2012; European Commission 2016). The cost-reduction pathway considered in this analysis will likely not be realized without sufficient domestic deployment. If the future market volume and outlook is uncertain, it is likely that costs will be higher than projected in this analysis. The model is not explicitly linked to specific deployment targets or supply chain maturity assumptions. Under the 86 GW projected by DOE’s *Wind Vision* (DOE 2015) study scenario, 2–3 GW of offshore wind deployment would be required annually until 2050. This level corresponds to present-day European deployment, but whether these deployment levels are sufficient for the U.S. supply chain to support the modeled cost reductions requires further analysis, which was not within the scope of this study.
- This analysis defines scenarios that assume that the U.S. offshore wind industry can leverage the recent European offshore wind technology and industry experiences while accounting for some significant physical, regulatory, and economic differences. The cost-reduction pathway under this scenario applies projected cost reductions developed for European projects, including sufficient learning and scaling effects and the development of U.S.-based labor skills and ocean-based infrastructure (e.g., assembly ports or vessels) (Navigant 2012; Valpy 2014; McClellan et al. 2015; Moné et al. 2015); however, the scope of the study did not include a full analysis to convert European offshore wind market conditions to U.S. market conditions.
- Although the model assumptions are based on sound engineering and economic principals, we see this as a first step in a process to quantify cost reductions for offshore wind energy and to better understand the market opportunities for offshore wind in the United States.
- Domestic cost reductions similar to those predicted in Figure ES-2 will require additional activities to reduce risk and uncertainty of early projects, including addressing U.S.-specific challenges (e.g., hurricanes, deeper water, Jones Act requirements) and incentivizing markets (see, e.g., Smith, Stehly, and Musial [2015] and McClellan et al. [2015]).

- Because the analysis was conducted at a national scale, it contains a number of simplifications and uncertainties that may affect the accuracy of reported results at any individual location. These uncertainties fall into four primary categories: (1) models—parameter studies were conducted with first-order tools and do not reflect detailed design (e.g., the analysis deliberately does not consider the possible impacts of wake interactions among potential wind projects); (2) cost data—no commercial-scale offshore wind power project has commercial operation status at the time of this assessment, which makes it difficult to validate assumptions; (3) suitability/availability of technology—new components (e.g., dynamic high-voltage cables) and equipment will be needed to install projects in the range of site conditions considered in this analysis; and (4) macroeconomic factors (e.g., exchange rates, commodity prices).
- The analysis does not consider several significant design variables that may contribute to variability among regions. For example, surface ice exposure will limit accessibility during winter months for projects in the Great Lakes and may have potentially large impacts on operational expenditures and availability; surface ice floes may also necessitate structural modifications (e.g., ice cones).
- This analysis includes a preliminary assessment of LACE limited by available data and a set of simplifying assumptions. Further refinement—which could include the consideration of competition among technologies, dynamic feedbacks from increasing renewable deployment on wholesale electricity prices, and export or import situations—and new data could improve this indicator. LACE also does not consider policy-related factors or subsidies, either nationally or in individual states. These factors may include renewable energy support mechanisms (e.g., the production tax credit, carbon pollution and other greenhouse gas regulations, state renewable portfolio standards, and loan guarantee programs), energy sector and environmental regulations, or benefits from portfolio diversification (EIA 2015b).
- The calculation of economic potential should not be used to project actual deployment. Economic viability indicates that a site may be able to compete in the local energy market, but it does not guarantee that it will successfully be deployed.
- The analysis does not aim to precisely estimate costs or avoided costs at any one location. As noted above, in some cases, the analysis was constrained by the availability of GIS data, existing model capabilities, and simplifications necessary to process data. These limitations are described in detail in later sections. The time frame of the analysis considered only the period to 2027 (COD). Because some offshore wind technology is still in a nascent stage of development, the analysis period should be considered a near-term window, especially for floating technology. It is expected that the viability of offshore wind technology will continue to improve beyond the analysis window; therefore, economic viability may lag in some regions where the technology and costs mature later.

Summary

This report describes a comprehensive effort to understand the cost of offshore wind energy for markets in the United States. The key findings show that offshore wind costs in the United States are expected to experience significant declines during the next decade under a scenario that assumes that the domestic market develops. A unique feature of this report is that it provides a new framework to assess the economic potential of offshore wind and a geospatial cost model that estimates the spatial variation in costs at different points in time. This preliminary

assessment shows that a significant number of economically viable offshore wind sites could emerge in the northeastern Atlantic and mid-Atlantic regions of the United States during the next decade even without direct dependence on policy incentives.

Further analyses are needed to refine our understanding and the quantification of factors that accurately reflect the costs, system value, and available revenue for new generation projects among different locations and over time. These include a range of sensitivity studies for a more robust understanding of cost components and their relationships to spatial parameters, validations of these findings and assumptions from the offshore wind stakeholder community, a detailed analysis of the output data set to provide additional insight into results for promising sites, and, last, additional geospatial layers and analysis to address spatial limitations (e.g., icing, hurricanes, geotechnical seabed conditions) and refined cost relationships and cost-reduction pathways.

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1 Introduction

This analysis describes the spatial-economic analysis conducted to provide insight into the characteristics of the U.S. offshore wind resource technical area and the impact of spatial and temporal variables on the economic viability of possible future projects using fixed-bottom and floating offshore wind technologies. Previous cost analyses conducted by the National Renewable Energy Laboratory (NREL) have focused on generating project-specific data (mostly proprietary) using a cost and scaling model (Fingersh, Hand, and Laxson 2006), analysis conducted for the U.S. Department of Energy (DOE) to help establish research targets (Moné et al. 2015; Tegen et al. 2013), or top-down economic analysis to establish market costs and trends (Smith, Stehly, and Musial 2015).

This study is NREL’s first comprehensive bottom-up analysis that combines previous analysis tools to answer critical questions about the economic viability of offshore wind in the United States. To conduct the study, NREL developed a geospatial economic model (NREL Offshore Wind Cost Model) that captures both the cost variability from one site to another throughout the U.S. offshore technical resource area and the cost variability due to technology and market advancements over time.

The modeling framework identifies the economic potential in the context of the greater offshore wind resource. Figure 1 depicts the offshore wind resource terminology that has been developed (Beiter and Musial 2016) for use in the recently updated offshore wind resource assessment (Musial et al. 2016) building on similar assessments (Brown et al. 2015; DOE 2013; Lopez et al. 2012).

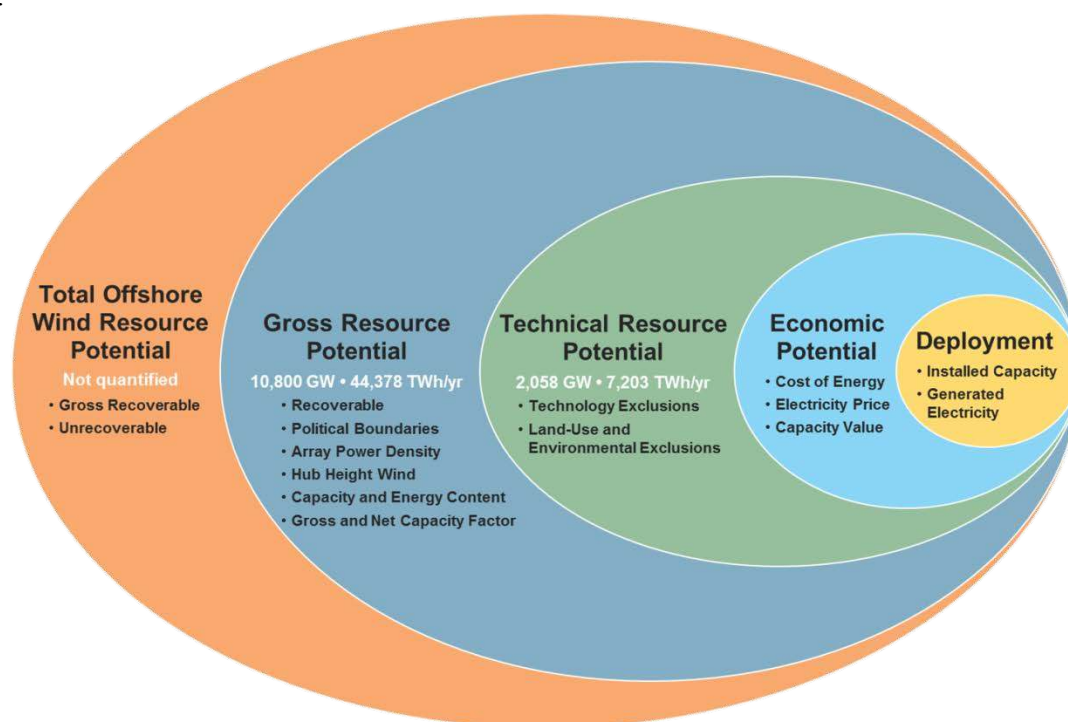


Figure 1. U.S. offshore wind resource terminology framework indicating estimated resource potential and classification criteria

In this framework, shown in Figure 1, the economic potential is a subset of the technical resource potential, which is restricted to proven offshore wind technology while also excluding major land-use and environmental siting conflicts. As such, technology exclusions include water depths greater than 1,000 m, wind speeds less than 7 m/s (at hub heights of 100 m), and locations in the Great Lakes where water depths are greater than 60 m. At water depths greater than 60 m, floating foundations are expected to be required, and technology that would allow floating foundations to survive in freshwater ice reliably does not currently exist. From Musial (2016), the technical resource potential of the United States was determined to be 2,058 GW of capacity or 7,203 TWh/yr. This potential provides a quantity of developable offshore wind resource that is approximately twice the electric energy consumption of the United States.

The economic potential for offshore wind in the United States had not yet been assessed, but the methodology has been documented for other technologies, including solar photovoltaics and land-based wind (Brown et al. 2015; DOE 2013; Lopez et al. 2012). Economic potential is defined as the subset of the available technical resource potential for which the cost required to generate the electricity, the levelized cost of energy (LCOE), is below the revenue available in terms of displaced energy and displaced capacity, otherwise known as the levelized avoided cost of energy (LACE).

The primary metric in this study is LCOE because more information and data are available on LCOE at this time, although the introduction of LACE is an important new variable that enables economic potential to be assessed. LCOE can be summarized as the net present value (NPV) of costs divided by the NPV of energy production. LCOE is a supply-side metric that considers only the factors that are endogenous to the project and that influence the costs to supply power from the project to the grid. The LCOE cost analysis combines wind power plant performance modeling, economic modeling, and national geospatial data layers to estimate the cost of potential projects by considering the following parameters:

- Water depth
- Wind resource
- Wave regime
- Seabed conditions
- Prospective staging ports
- Possible inshore assembly areas
- Existing grid features and potential connection points
- Environmentally sensitive areas
- Competitive-use areas.

As part of this study, LCOE values are compared to LACE values to estimate the available revenue for offshore wind power projects. LACE comprises the NPV of revenue from wholesale electricity prices and capacity value divided by the NPV of energy production. LACE is a demand-side metric; it considers the value from load, transmission constraints, and the existing mix of generation that offshore wind may replace. The LACE analysis method provides an

approximation of the available revenue to an offshore wind power project by considering the following parameters:

- Wholesale electricity prices
- Market marginal costs (system lambdas)
- Capacity credit
- Capacity payment.

The resulting output data allows for the difference between LCOE and LACE to be calculated at more than 7,000 offshore wind sites and to generate heat maps that visually highlight project sites. The LCOE results are disaggregated into component parts (e.g., capital expenditures [CapEx], operational expenditures [OpEx], and annual energy production [AEP]), to provide insight into the sensitivities related to key spatial parameters. When comparing LCOE (a proxy for required revenue) to LACE (a proxy for available revenue), an indication of the economic viability of a potential offshore wind power project can be obtained. Whenever LACE is greater than LCOE at a given location, that site is considered to have economic potential.

This study considers how a variety of spatial and temporal parameters influence the LCOE and LACE for offshore wind. It considers both fixed-bottom and floating offshore wind technologies. The new spatial-economic methodology was used to develop a model to enable the prediction of offshore wind system cost and performance over time and how it is influenced by technology innovation and learning-by-doing effects within the industry. Estimates of offshore wind costs are calculated for 3 years corresponding to commercial operation dates (CODs) of 2015, 2022, and 2027.

In 2015, a baseline turbine rating of 3.4 MW was used to reflect the weighted average of installed offshore wind power projects globally in 2014 (Moné et al. 2015). Informed by recent industry trends, turbine ratings of 6 MW and 10 MW were assumed for the technology corresponding to CODs of 2022 and 2027, respectively. Various assumptions were made to account for the nascent stage of the U.S. offshore wind industry and to make projections into the future. Cost reductions projected between 2015 (COD) and 2027 (COD) were based on estimates from offshore wind assessments conducted by The Crown Estates, BVG Consultants, and KIC InnoEnergy (Crown Estates 2012; Valpy 2014).

Because the first U.S. offshore wind power project will not come online for commercial operation until late 2016, U.S. developers are expected to leverage European offshore wind technology, industry experience, and industrial capacity to initiate the first projects while accounting for European/U.S. physical and economic differences.¹² It is likely that the cost reductions assumed for this assessment are achievable only with continued global technology innovations (e.g., trends in increasing turbine size) in conjunction with increasing levels of

¹² Some key differences between European and U.S. markets include currency exchange rates, existing infrastructure, project finance, supply chain maturity, vessel availability (e.g., Jones Act requirements), workforce readiness, and physical characteristics of the offshore wind siting environment. Costs could also be influenced by U.S.-specific political considerations, including regulatory structures, tax codes, and incentive programs (Smith, Stehly, and Musial 2015).

domestic deployment and future market visibility, leading to the near-term establishment of a sustained domestic supply chain.

Generally, the model indicates that over time the bottom-up cost variables contribute in unison to overall cost decreases over time, which is expected. Similarly, revenue streams from wholesale electricity prices and capacity payments among U.S. coastal areas are generally expected to increase gradually over time “as a result of rising costs for power generation and delivery” (Energy Information Administration [EIA] 2015a).¹³ This analysis provides a preliminary assessment of the convergence of these LCOE/LACE trajectories and how it can be translated into economic potential.

This analysis does not consider policy-related factors as part of LACE or LCOE, such as renewable energy support mechanisms (e.g., the production tax credit), energy sector and environmental regulations (e.g., carbon pricing), or benefits from portfolio diversification (EIA 2015). All data presented are unsubsidized but considers accelerated depreciation (Modified Accelerated Cost Recovery [MACRS]).

The outputs of this analysis are intended to provide information that federal and state agencies and planning commissions could use to inform strategic decisions about offshore wind development in the United States. The reader should note, however, that the emphasis of this analysis is on assessing the relative LCOE and LACE impacts of changes in spatial variables throughout the U.S. technical resource area. The analysis does not aim to precisely estimate costs at any one location or the potential for cost reduction from any single component. Analysts operated within the constraints of available geographic information system (GIS) data availability, existing model capabilities, and simplifications necessary to process data. These limitations are described in detail in later sections.

Many of the important details about the specific assumptions and limitations of this analysis are described in the appendices. This report is organized as follows:

- Section 2: Offshore Wind Technologies
- Section 3: Methodology
- Section 4: Spatial Characteristics of the U.S. Offshore Technical Resource Potential Area
- Section 5: Wind Power Plant Performance Modeling
- Section 6: Wind Power Plant Cost Modeling
- Section 7: Cost-Reduction Pathways
- Section 8: Results
- Section 9: Next Steps (including discussion, conclusions, and recommendations)

¹³ Although EIA (2015a) and other sources generally predict an increase in power generation and electricity delivery costs, a range of factors may influence future electricity costs, some of which are challenging to predict. These may include (but are not limited to) future developments in energy efficiency, transportation, and storage; changes in fuel prices and generation technologies; market structures; and macroeconomic factors.

- Appendix A: Overview of Geographic Information System Layer Development
- Appendix B: Performance Modeling
- Appendix C: Calculation of Location-Specific Costs.

2 Offshore Wind Technologies

The technology used in offshore wind systems evolved from land-based wind turbines in the late 1990s and was commercialized in European seas in the beginning of the twenty-first century. As long-term offshore market visibility grew, largely through policy commitments made by the European Union and its member states, offshore technology investments increased, resulting in technology advancements during the past decade. Many of these innovations, such as 6-MW–8-MW turbines, have only recently reached commercial-scale production, with slightly less than 12 GW of offshore wind installed by the end of 2015 (Smith, Stehly, and Musial 2015).

Figure 2 shows all of the offshore wind power projects installed globally as well as those in the regulatory pipeline as of June 2015 as a function of depth and distance to shore. Almost all offshore wind turbines that have been installed are rigidly fixed to the sea bottom and are sited in waters with depths less than 50 m. Figure 2 also shows a significant number of planned and approved projects located farther from shore.

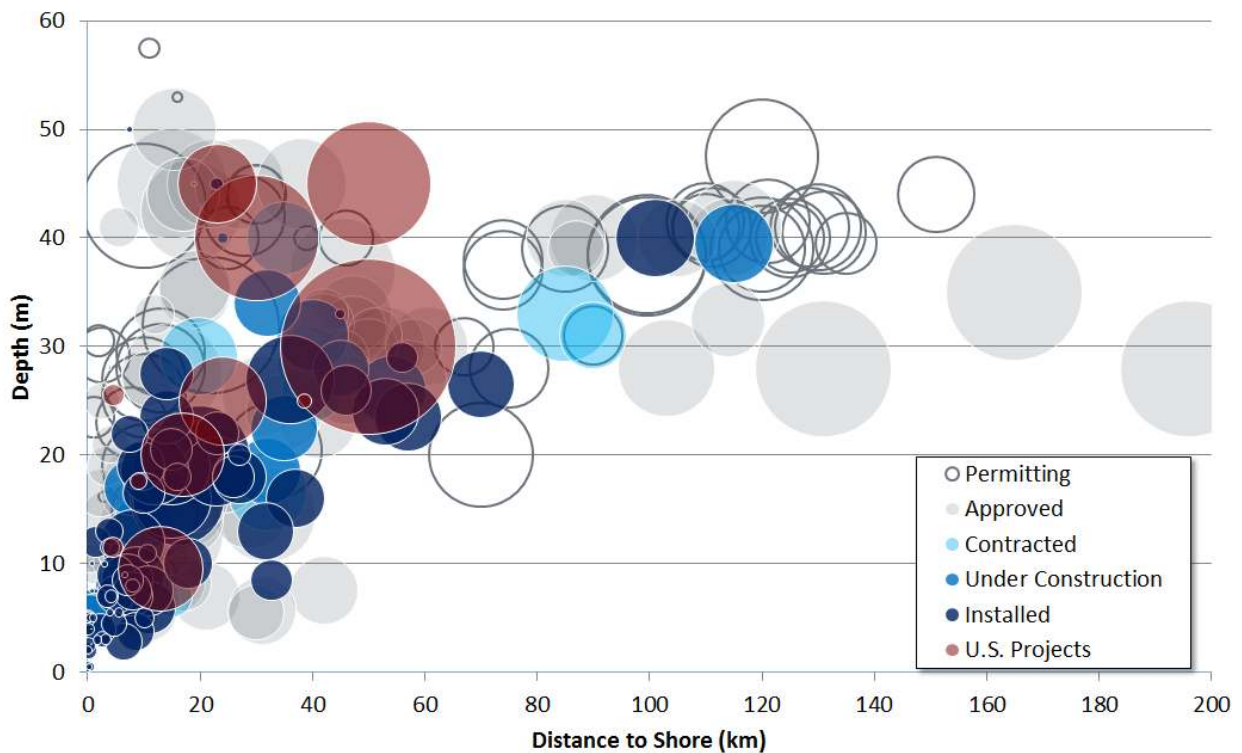


Figure 2. Global offshore wind power projects as a function of water depth and distance to shore.
Image from Smith, Stehly, and Musial (2015)

Although the industry has thus far stayed mostly in shallower water, significant offshore wind resources exist in areas with depths much greater than where fixed systems are being deployed today (Musial 2016; James and Ros 2015). For these deeper water offshore wind resource areas, floating wind technology is being considered and may be a more viable, longer-term option. Although only five commercial-scale floating turbines have been deployed at the time of this analysis, the floating offshore wind market appears to be growing, and evidence is building that floating systems may have the potential to achieve costs that are similar or even lower than those

of fixed-bottom systems. Figure 3 shows the current market for floating offshore wind. The figure indicates that floating projects may be entering a new, precommercial phase.

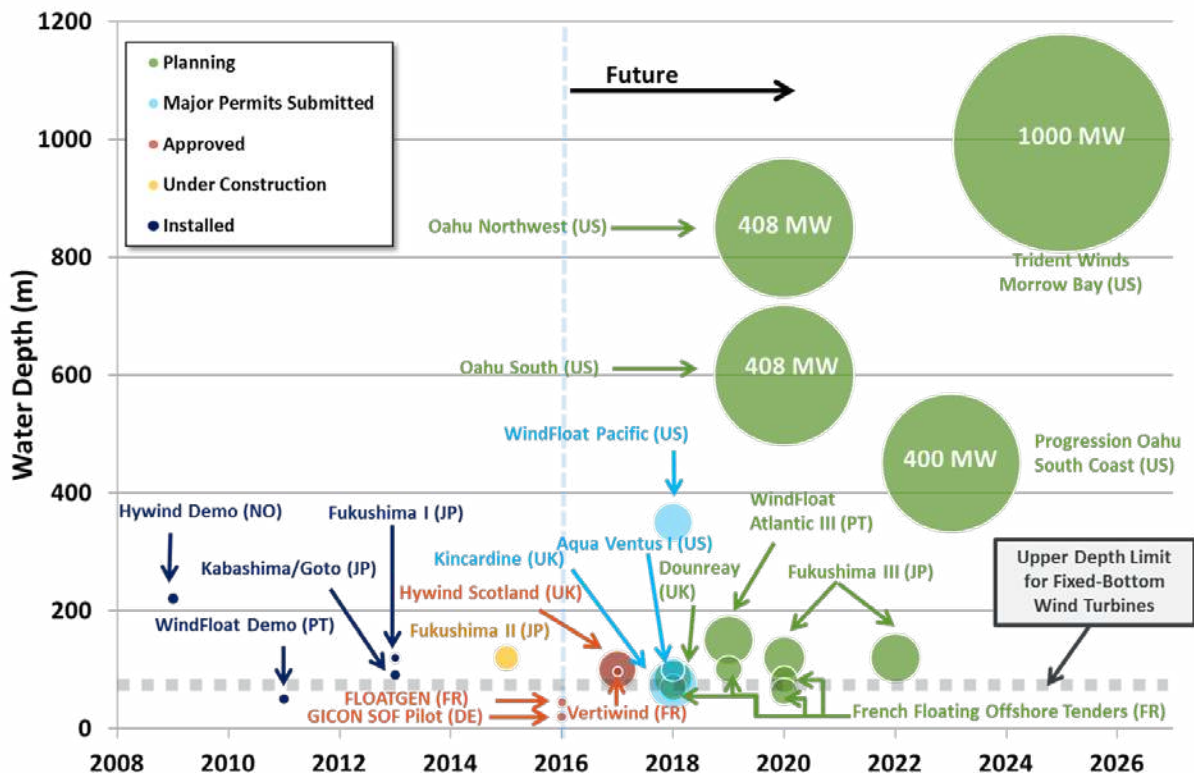


Figure 3. Status of the global floating offshore wind industry as of May 2016.

The assumption that cost-reduction potential is achievable is based on several European studies and assessments that were made as part of this study (Catapult 2015; James and Ros 2015). Although floating offshore wind cost-reduction opportunities appear to be significant, they are different than fixed-bottom systems, and therefore the criteria for floating wind systems require a unique capital cost breakdown structure and set of assumptions. For example, opportunities to reduce labor and vessel costs at sea may be able to offset some of the other costs associated with higher hull costs (James and Ros 2015).

Figure 4 illustrates the full spectrum of water depths at which offshore wind turbines are deployed and the corresponding substructure technologies. Generally, each of these substructure types have evolved or been adapted from oil and gas platforms.

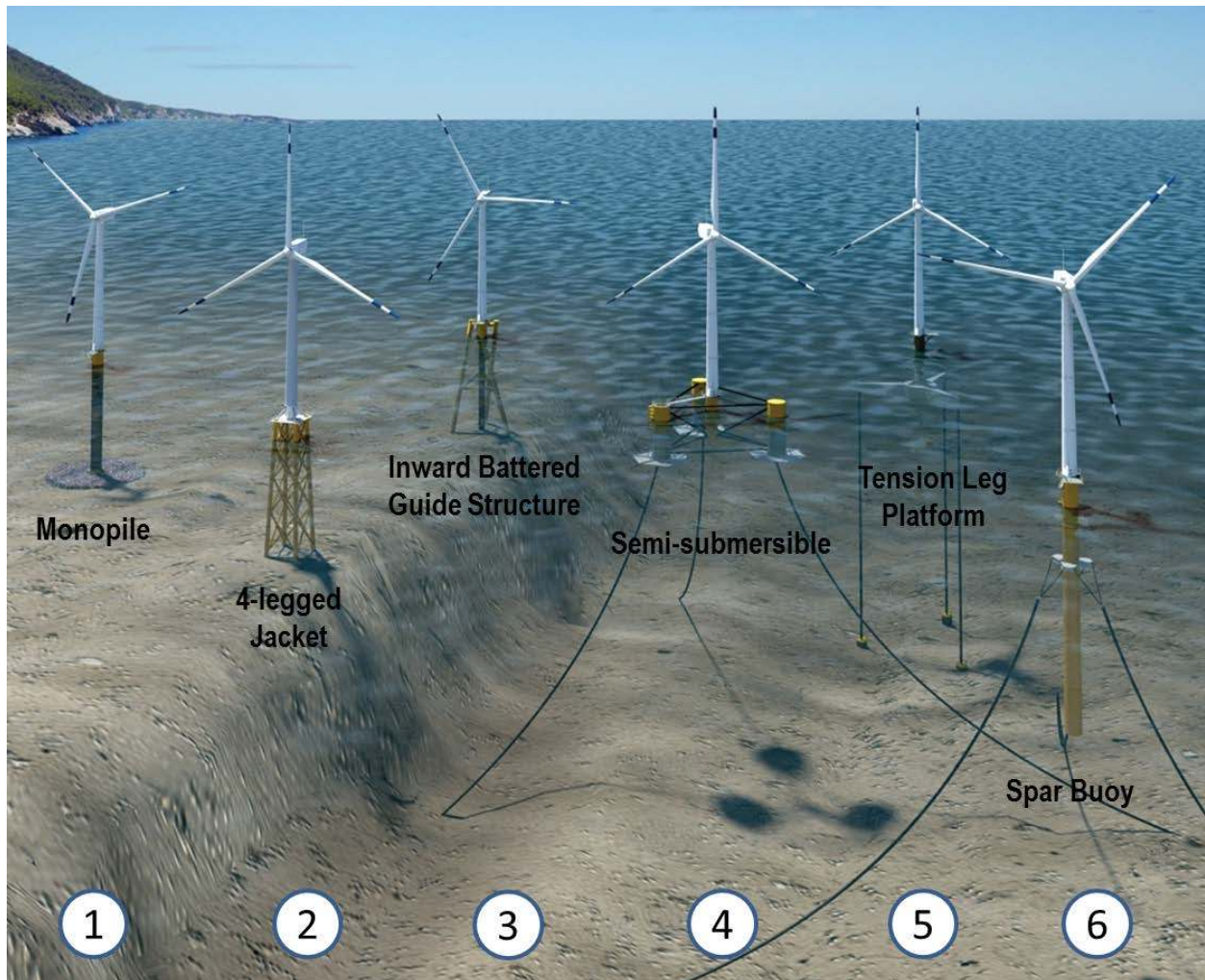


Figure 4. Offshore wind substructure types for varying water depths. This study used the (1) monopile, (2) four-legged jacket, (4) semisubmersible, (5) tension leg platform, and (6) spar buoy.
Illustration by Josh Bauer, NREL

Shown on the left side of Figure 4, the monopile (1) is the most common substructure in the industry and functions well in shallower sites with stiff soils. The four-legged jacket (2) is becoming more common in slightly deeper water, and it is generally less sensitive to soil stiffness. The inward battered guide structure (3) was developed as a type of jacket that reduces installation complexity and lowers the number of parts, and it is being considered by several projects in the United States. The semisubmersible (4) is a floating substructure that can be deployed in water as shallow as 50 m. Using a semisubmersible depends primarily on buoyancy or water plane area to maintain static stability, but it has a key advantage of being stable during loading while having a shallow draft. The tension leg platform (5) gets its static stability from mooring-line tension; therefore, it is unstable until the mooring lines are attached, and it can be difficult to deploy, but it is very stable once installed. The spar buoy (6) is stabilized by a ballast, and it has a deep draft that avoids surface wave action (Musial and Ram 2010).

Although all of these concepts have advantages and disadvantages, the optimum structure depends significantly on geospatial variables, such as bathymetry, soil conditions, and availability of vessels and infrastructure.

For this study, only four of these six concepts were considered: the monopile, four-legged jacket, semisubmersible, and spar buoy. These substructure types were chosen for the following reasons:

- Collectively, they represent the full range of water depths to provide the necessary information to predict the cost-optimal choice between two technologies (e.g. between fixed-bottom and floating technologies) dependent upon a geospatial variable, such as water depth or distance from shore (hereafter referred to as economic “break point”).
- Enough design information was available to accurately analyze each concept.
- Enough industry experience has been acquired for each substructure to verify results.

However, the choice to focus on these substructure technology architectures should not be interpreted as a down-selection process to weed out the other alternatives. On the contrary, new technology advancements are continuously underway, and researchers recognize that it is possible that future optimized systems may not be well represented by these concepts.

3 Methodology

This section provides a high-level overview of the methodology that underpins this analysis. The overall objective of this analysis is to enable analysts to quantify the impact of key spatial parameters on the economics of projects within the U.S. offshore technical potential resource area.¹⁴ The analysis included the following six activities:

1. Collect and process multiple spatial data sets to create a unified, multilayer GIS database that describes key attributes of the U.S. offshore technical potential resource area.
2. Develop plant layout and technology assumptions, and specify an energy capture model to estimate plant performance for all potential projects within the U.S. offshore resource area.
3. Modify NREL's existing suite of fixed-bottom and floating offshore wind economic models, and conduct parametric studies to investigate the relationships among key categories of expenditures and spatial parameters.
4. Conduct analysis to determine cost-reduction pathways through technology advancement for offshore wind, and quantify the impacts and associated cost reductions on LCOE among U.S. coastal sites.
5. Collect and process wholesale electricity price and capacity value data to calculate available revenue to offshore wind power projects (captured by LACE).
6. Compare LCOE and LACE at U.S coastal sites to derive an indication of their economic viability.

These input categories were evaluated jointly within a data processing framework to estimate LCOE for each location within the offshore resource technical area.

Although the focus of this study has been on offshore wind cost assessment, the economic viability of potential offshore wind sites is assessed in a final step by comparing offshore wind costs to a set of "avoided cost" variables that proxy the revenue available to offshore wind power projects. The latter comprises an initial effort of applying a method for assessing economic viability adapted from EIA (2013).

The scope of the assessment covers the major offshore areas within the contiguous United States and Hawaii, including the Atlantic Ocean, Gulf of Mexico, West Coast Pacific Ocean, Hawaii Pacific Ocean, and the Great Lakes. The spatial-economic assessment extends as far as 370.4 km (200 nm) off the nearest landmass, corresponding to the U.S. exclusive economic zone, but it is limited to regions with water depths ranging from 0 m–1,000 m and wind speeds greater than 7 m/s (at hub heights of 100 m). A conceptual offshore wind power plant was developed that consists of 100 generic 6-MW turbines with 155-m rotors. The turbines are laid out in a 10-by-10 square array and spaced 7 rotor diameters apart. This conceptual array was used both in the cost model to calculate geospatial variability and in Openwind to calculate AEP and wake losses. The spatial-economic cost model was run for the entire technical resource area. A full description of this cost model is provided in Section 3.1.2.

¹⁴ The full description of the methodology is extensive and can be found in the appendices.

The energy capture and wake losses were calculated separately for each single array using Openwind software developed by AWS Truepower. The conceptual 600-MW array was modeled more than 7,159 times in Openwind using a script that repositioned it around the U.S. offshore resource area from 0 nm–50 nm to determine the geospatial variability of energy production and corresponding wake losses. Areas that were farther than 50 nm from shore were assigned the values calculated at the 50-nm distance. A full description of the plant layout and the AEP calculation process is provided in Section 5.

Many of the important details about the assumptions and limitations of the methodology are described in the appendices.

3.1 Cost of Energy Modeling Approach

Because the first U.S. offshore wind power project will not come online for commercial operation until late 2016, U.S. developers can be expected to leverage European offshore wind technology and industry experience while accounting for significant physical, regulatory, and economic differences. Some key differences between European and U.S. markets include currency exchange rates, existing infrastructure, supply chain maturity, vessel availability (e.g., Jones Act requirements), workforce readiness, project finance, and physical characteristics of the offshore wind-siting environment. The cost could also be influenced by U.S.-specific political considerations, including regulatory structures, tax codes, and incentive programs (Smith, Stehly, and Musial 2015). Similarly, existing cost models and cost-reduction pathway analysis focused on European projects (e.g., Figure ES-2) can help establish U.S. baseline and cost trends (DOE 2015). This analysis relies on European cost data and cost-reduction pathways for some of its assumptions and baseline values.

Recent offshore wind cost projections for the United States include those from Smith, Stehly and Musial (2015) and Kempton, McClellan, and D. Ozkan (2016). This analysis extends these existing assessments by reflecting the most recent cost data available from literature and industry knowledge and combining them with a spatial assessment. Information from industry was provided through interviews and exchange of data; conclusions that were drawn from this data were validated through a peer review process. This section describes the general approach for estimating costs at 7,454 U.S. coastal sites, including the general LCOE metric applied in this analysis (Section 3.1.1); the method for the spatial and temporal assessments of LCOE (Section 3.1.1.1 and Section 3.1.1.2, respectively); and NREL’s Offshore Wind Cost Model (Section 3.1.2).

3.1.1 Levelized Cost of Energy

The LCOE was used as the central metric for the economic evaluation of wind power plant locations. It can be summarized as the NPV of all project expenditures divided by the NPV of energy production. In this assessment, however, the discounted cash flow is approximated through the use of annualized values that are representative of lifetime¹⁵ averages.

The LCOE metric excludes policy incentives (e.g., renewable energy credits) and any revenue streams that may be available to an offshore wind power project within a specific state or

¹⁵ In this analysis, 20 years were assumed for offshore wind project lifetime.

region.¹⁶ Revenue sources, such as wholesale electricity prices and capacity payments, are considered as part of LACE. For the purpose of this analysis, this metric is calculated at the point of interconnection with the existing electricity grid.

Four major inputs are entered into the LCOE equation. Three parameters—CapEx, OpEx, and AEP—enable the equation to represent system impacts from design changes. The total costs of financing are represented by the fourth major input: a fixed charge rate (FCR). FCR is defined as the amount of revenue per dollar of investment that must be collected annually to pay carrying charges on the investment as well as taxes.

A number of different methodologies have been developed to calculate LCOE. This analysis uses a methodology adapted from Short et al. (1995), which offers the following general equation:

$$\text{LCOE} = \frac{(\text{FCR} * \text{CapEx}) + \text{OpEx}}{\text{AEP}_{\text{net}}} \quad (2)$$

where:

- FCR = fixed charge rate (%; see Appendix C)
- CapEx = capital expenditures (\$/kW)
- AEP_{net} = net annual energy production (kWh/yr)
- OpEx = annual operational expenditures (\$/kW/yr).

To simplify the calculation of costs, the LCOE elements are sorted into three categories: fixed costs, variable costs, and cost multipliers.

Fixed costs refer to cost categories that do not have an empirically discernable relationship with the included spatial parameters based on current knowledge and market context. Offshore wind turbine procurement costs, for example, are assumed to be site-agnostic given that commercially available models are typically designed for International Electrotechnical Commission Class 1 sites. In practice, however, wind turbine original equipment manufacturers hold liabilities associated with warranty provisions and may adjust the pricing structure for a given site to account for the perceived level of risk associated with exposure to environmental conditions. In general, we assume that these costs are constant from one project to another.

Variable costs refer to categories of expenditures that have distinct relationships with spatial parameters. For example, installation costs are expected to vary with logistical distances (e.g., distance from port to site), water depth, and prevailing meteorological ocean (metocean) conditions.

Cost multipliers are indirectly related to environmental conditions. They are not explicitly linked to individual spatial factors but tend to vary with total project cost to reflect the complexity of

¹⁶ LCOE does, however, account for the value of the Modified Accelerated Cost Recovery System, which allows renewable energy project owners to depreciate CapEx during a 5-year schedule. The Modified Accelerated Cost Recovery System is a part of the permanent tax code and is included in LCOE because NREL views it as a structural feature of the U.S. market.

other items. For instance, engineering and management costs incurred from financial close through commercial operations are applied as a percentage of CapEx.

Section 6 and Appendix C provide details about the bottom-up method for calculating CapEx, OpEx, and AEP from spatial parameters. Appendix C also has additional information about FCR, the financial parameter that is used to approximate the average annual payment required to cover the carrying charges on an investment and tax obligations.

3.1.1.1 Spatial Cost Method

Each offshore wind site location has a unique set of geospatial variables related to the cost of electric energy delivery. For a given point in time, a wide range of LCOE can exist among U.S. coastal sites. These spatial variables can include but are not limited to the quality of the wind resource, turbine accessibility as a result of varying sea states, distance from shore, water depth, soil and substructure suitability, and availability of critical infrastructure. For example, sites that are closer to shore may benefit from lower electric transmission, construction, operation and maintenance (O&M) costs; sites farther from shore may benefit from lower costs as a result of higher energy production.

The spatial aspect of the cost modeling approach is structured around input data from a geospatial assessment, performance modeling, and relationships among spatial variables and costs that were developed for this analysis. NREL's cost modeling framework combines these different inputs and calculates LCOE as described in Section 3.1.2 for 7,454 sites. Available output includes cost heat maps and offshore wind supply curves (the latter is not shown as part of this analysis). Figure 5 illustrates these different components.

The geospatial assessment and performance modeling are described in Section 4 and Section 5, respectively. To identify reasonable relationships among variable cost items and environmental conditions at potential offshore wind power project locations, a series of parameter studies were conducted to identify how project economics change with respect to key spatial parameters. In particular, these parameter study modules cover the following components:

- **Substructures.** Costs vary depending on the type of substructure (see Figure 4) and water depth. Soil conditions are not considered in this study due to lack of data.
- **Electrical infrastructure.** Electrical infrastructure costs are influenced by the type of export cables and losses, which both depend on the distance from shore. The cost model determines the least-cost technology, including high-voltage direct current (HVDC) if project sites are far from shore. No provisions are made in the cost model to aggregate wind power plants for reducing transmission capital costs among multiple projects.
- **Installation.** Spatial installation parameters that influence costs include distance to assembly ports, distance to sites, availability of construction vessels (e.g., Jones Act restrictions), and technology-specific limitations that may vary geographically. Each floating technology is assumed to use a unique set of installation procedures that factors into cost.
- **Operation and maintenance.** The O&M parameter study considers sea states at each site to establish turbine accessibility and unique availability assumptions. It also takes into account

distance to shore from each site. Technology-specific assumptions influence the O&M cost, especially in the choice between fixed and floating designs for a given location.

The variation in costs is caused by the combination of these spatial factors. An overview of the set of models, tools, assumptions, and data that were analyzed to derive these relationships is depicted in Figure 5 and described in Section 6 and Appendix C, which provides a detailed summary of the spatial-cost parameter studies. As new technology is developed over time, these spatial variables are modified to take advantage of advancements. This is addressed in the next section.

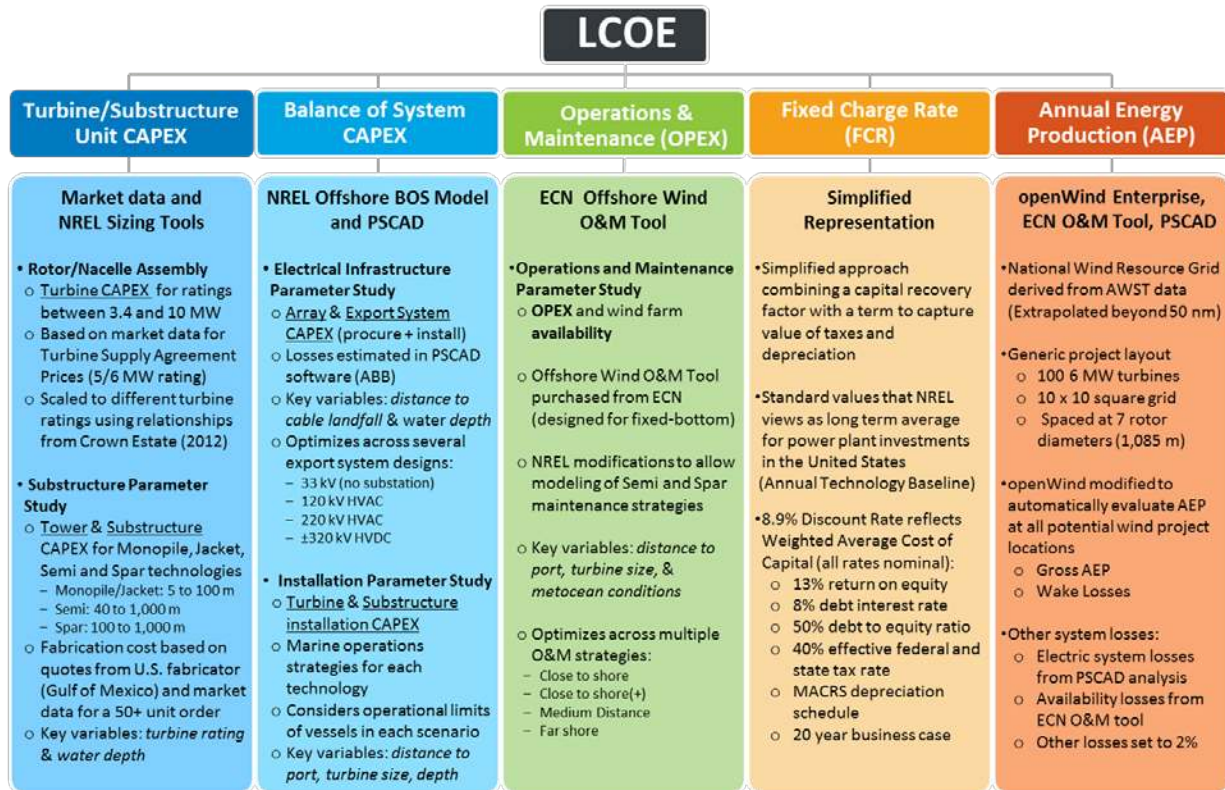


Figure 5. LCOE calculation framework and modeling assumptions

Finally, the number of distinct offshore wind power plant locations reported in Section 4 were reduced based on screening against specific metrics before conducting the cost assessment. Ice regions in the Great Lakes were excluded where depths are greater than 60 m because floating wind technology that can survive freshwater ice floes does not currently exist. In addition, some offshore wind power plant locations where more than half of the area fell on land were excluded. These exclusions from the technical resource area reduce the number of U.S. offshore wind power plant sites from 7,823 to 7,454.

3.1.1.2 Temporal Cost Method

Larger turbines, bespoke vessels and infrastructure, and drivetrain innovation have led to lower costs in elements of offshore designs; however, until recently, these forward strides have been offset in many cases by more challenging siting conditions (i.e., geospatial variability). Shallower, easy-to-access sites were developed first, when the technology was in a more nascent

stage, but these sites can be scarce and potentially more conflicted by other human activities and environmental sensitivities because they are closer to shore (Musial 2016). The offshore wind industry adapted the technology to deeper water and sites that were farther from shore (see Figure 1), increasing the cost of marine operations, foundation cost, distance to ports and interconnection points, and overall project complexity. Nevertheless, as the current generation of 6-MW–8-MW offshore wind turbines has entered the market during the past few years, a marked decline in LCOE has been observed (Smith, Stehly, and Musial 2015).

These changes in LCOE are generally the result of a set of factors related to technology advancement and market development that have been realized over time and which have enabled developers to build in more challenging conditions, farther from shore, where better wind resources are available. Among the drivers of these time-dependent cost reductions are technology advancements that lower the cost for CapEx (e.g., turbine, substructures, electrical infrastructure), operations, or financing or, conversely, factors that raise the annual energy output of the turbines. This study models the benefits of technology and market advancement variables that can be realized over time. The study further assumes that all technology advancements would be equally available to all regions in the United States.

Details of the model, its assumptions, and any modifications introduced are described in Section 7. In particular, it describes some essential cost-reduction pathway assumptions that were derived and modified from the DELPHOS tool, which was developed in the United Kingdom by BVG Consulting and KIC InnoEnergy (Valpy 2014). In addition to the above improvements, large LCOE benefits were anticipated from turbine size increases. For the study focus years financial close (FC) 2013 (2015 COD), FC 2020 (2022 COD), and FC 2025 (2027 COD), turbine technology was defined according to Table 1. The turbine technology indicated in Table 2 was assigned in the beginning of each focus year and held constant at all sites until the next focus year.

Table 1. Summary of Key Assumptions for Spatial-Economic Assessment

Key Assumptions	FC	2013	2020	2025
	COD	2015	2022	2027
Turbine Rated Power (MW)		3.4	6	10
Plant Size (MW)		600	600	600
Turbine Hub Height (m)		85	100	125
Turbine Rotor Diameter (m)		115	155	205
Turbine Specific Power ^a (W/m ²)		327	318	303

^a A wind turbine’s specific power is the ratio of its nameplate capacity rating to its rotor-swept area. All else equal, a decline in specific power should lead to an increase in capacity factor.

Corresponding to the line-item reductions from the DELPHOS tool (Valpy et al. 2014), a range of technology assumptions were made for the three focus years.

3.1.1.2.1 Technology Assumptions for 2015 (COD) (Baseline)

The baseline technology assumed for this analysis is a 3.4-MW turbine. This turbine size has been chosen to correspond to the weighted average nameplate capacity of turbines installed in 2014 (Smith, Stehly, and Musial 2015). Although the larger, 6-MW turbines were being deployed in 2015, this analysis relies on the weighted average of installed turbine size that were expected to be installed in 2015 based on FC 2013 data. This assumption reflects more conservative costs for the U.S. market and is likely to result in higher than actual market prices for some projects. The choice for substructure types (jacket and monopile foundations for the fixed-bottom technology; spar and semisubmersible foundations for the floating technology) was made based on the cost optimization depending on the spatial characteristics at individual locations.

3.1.1.2.2 Technology Assumptions for 2022 (COD)

For 2022 (COD), a 6-MW turbine was chosen, which was informed by announced turbine supply agreements and partnerships in 2015 indicating that by 2019/2020, an average of between 6 MW–8 MW will be reached in Europe (Smith, Stehly, and Musial 2015). Some industry information indicates the use of 8-MW–9-MW turbines by that date. The lower end from the range indicated in Smith, Stehly, and Musial (2015), 6 MW, was chosen for the fixed-bottom technology assuming that, due to Jones Act restrictions, the installation of 8-MW turbines may be precluded in 2022 due to a lack of sufficient heavy-lift vessels; however, it is assumed that Jones Act-compliant vessels would be available for a 6-MW turbine by 2022 (COD). For floating technology, a 6-MW turbine was chosen to allow for a more direct comparison to the fixed-bottom technology even though it is assumed that floating technology will have less dependence on large installation vessels. The choice for substructure types (jacket and monopile foundations for the fixed-bottom technology; spar and semisubmersible foundations for the floating technology) was made based on the cost optimization depending on the spatial characteristics at individual locations.

3.1.1.2.3 Technology Assumptions for 2027 (COD)

By 2027 (COD), it is assumed that Jones Act-compliant installation methods will be available that could be used for 10-MW installations. Despite a number of technical-, infrastructure-, and vessel-related challenges associated with upscaling turbines beyond 6 MW, leading offshore wind turbine original equipment manufacturers have indicated that they will have a design of 10 MW or more in the prototype stage by 2020 (Smith, Stehly, and Musial 2015) and 10 MW–12 MW in use by 2027 (COD), so this technology will likely be available for commercial deployment by 2027 (COD). For floating technology, a 10-MW turbine was also chosen, which allows for the direct comparison to the fixed-bottom technology. The choice for substructure types (jacket and monopile foundations for the fixed-bottom technology; spar and semisubmersible foundations for the floating technology) was made based on the cost optimization depending on the spatial characteristics at individual locations.

3.1.1.3 Cost-Reduction Scenarios

Based on these turbine sizes and the general assumptions shown in Table 1, two generic reference sites were evaluated under the cost-reduction scenario in this analysis. These generic cost-reduction scenarios approximate the average site conditions at the current BOEM wind energy areas along the East Coast, but they do not represent any specific site (Smith, Stehly, and

Musial 2015). A set of additional technology and spatial assumptions were made to define these reference sites, as shown in Table 2. Although semisubmersible foundation types were chosen for the floating technology throughout the time period considered in this analysis, assumed fixed-bottom substructure types vary by year. For 2015 (COD), monopile foundations were most commonly installed in Europe in 2015, so they were chosen as representative of the fixed-bottom technology substructure type. Because project developments are expected to move toward larger turbine sizes by 2022 (COD), jacket foundations will become more likely for the fixed-bottom technology, so they were chosen to represent the substructure type in that year. Jacket foundations were also chosen for 2027 (COD).

Table 2. Summary of Additional Assumptions for Reference Scenarios

Assumptions	FC	2013	2020	2025
	COD	2015	2022	2027
Water Depth (m)	Fixed	30	30	30
	Floating	100	100	100
Foundation/ Substructure	Fixed	Monopile foundation	Jacket foundation	Jacket foundation
	Floating	Semisubmersible foundation	Semisubmersible foundation	Semisubmersible foundation
Distance from Shore (km)		30	30	30
Plant Resource (m/s at 90 m above sea level)		8.9	8.9	8.9
Net capacity factor (%)		42	45	50

3.1.2 Offshore Wind Cost Model

NREL’s Offshore Wind Cost Model is a data processing framework and combines the outputs derived from the spatial and temporal assessments described in Section 3.1.1.1 and Section 3.1.1.2. A Python-based¹⁷ data processing framework was developed to automate the calculation of location-specific costs for 7,454 distinct wind power plant layouts of 600 MW each throughout the U.S. technical resource area. The model takes as input the GIS data set described in Section 4 and a set of user-specified “scenario” values (Figure 6). This information is used to compute scenario-specific outputs in four steps:

1. The wind power plant performance model output provides estimates of AEP at each plant location, and minor corrections are applied for turbine size, transmission distance, and availability losses (Section 5).
2. Component costs for 2015 (COD) are estimated using parameterized equations (see Section 6).

¹⁷ Python is a general-purpose, interpreted, dynamic programming language.

3. Cost reductions from the DELPHOS tool¹⁸ (Valpy 2014) are applied by subsystem to estimate costs in 2015 (COD), 2022 (COD), and 2027 (COD) (see Section 7).
4. Subsystem costs are summed to estimate project costs and LCOE for each of the 7,454 wind power plant locations.

To obtain the cost-optimal substructure type, this process is repeated for each scenario (substructure type and turbine size). The scenario with the lowest LCOE value is selected as the anticipated LCOE value for that location for that year. An exponential fit of the form:

$$\text{LCOE}_{\text{fit}} = Ae^{-\beta \cdot \text{year}} + C$$

is applied to these “lowest LCOE” values among the 3 years at each location. Here, A , β , and C are all fit coefficients. These fits are then used to interpolate LCOE to points in time between the focus years (2015, 2022, and 2027 COD), and to extrapolate to 2030 (COD).

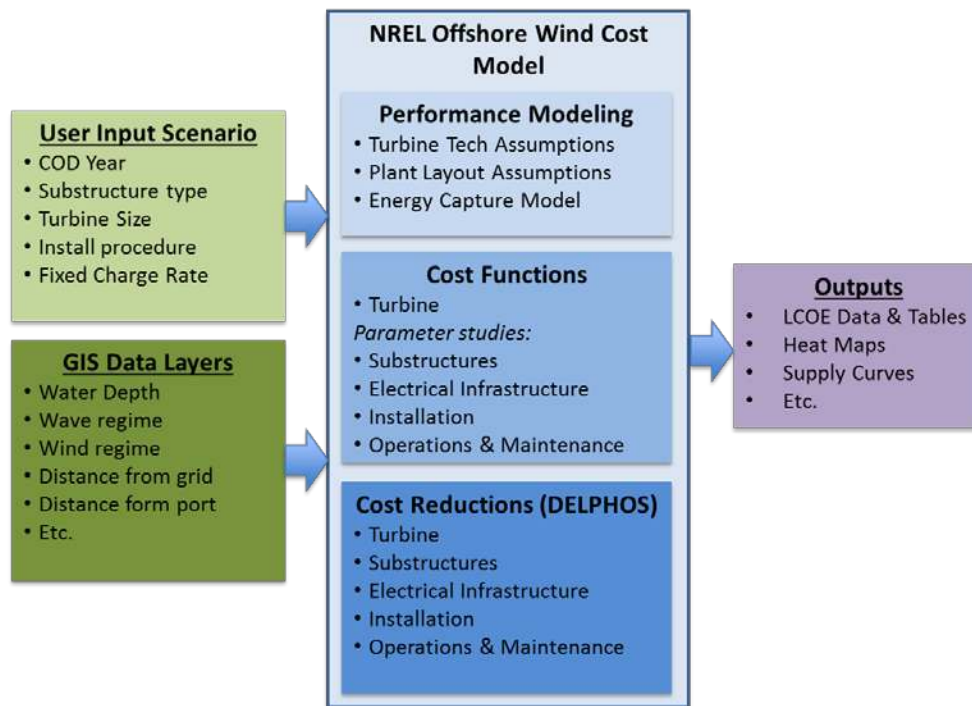


Figure 6. Schematic of modeling approach

Note: Inputs (green), NREL Offshore Wind Cost Model (blue), and outputs (lavender)

3.2 Avoided Cost Modeling Approach

Although the focus of this study has been on an assessment of offshore wind cost of energy, the economic viability of potential offshore wind sites has also been assessed by comparing offshore

¹⁸ According to KIC InnoEnergy, the DELPHOS tool comprises “a series of cost models and basic data sets to improve the analysis of the impact of innovations on [future offshore wind] costs” (<http://www.kic-innoenergy.com/delphos/>). It is described in greater detail in Section 7.

wind costs to a set of avoided cost variables that proxy the revenue available to offshore wind power projects.

For an assessment of economic viability, the LCOE metric is limited to cost multipliers only; it does not reflect factors that capture impacts to the system that a new generation resource may provide to local electricity markets or the type of generation that is being displaced. Avoided costs can be thought of as the potential available revenue to new generation, which may vary significantly from one U.S. coastal region to another. The LACE metric, introduced by the EIA, approximates what it would cost to generate the electricity that is otherwise displaced by a new generation project (EIA 2015b; Namovicz 2013; EIA 2013).

The LACE metric estimated for this analysis captures two revenue sources: marginal generation price and capacity value.¹⁹ Similar to the LCOE calculation, we approximate the discounted cash flow through the use of annualized values that are representative of lifetime²⁰ averages. Multiple ways to calculate available revenue to generation sources and various terms (e.g., market value) are in use (Massachusetts Institute of Technology 2015; Hirth 2013). For this analysis, we applied a methodology adapted from the EIA (Namovicz 2013; EIA 2013), which offers the following general equation:

$$\text{LACE} = \frac{MP * AEP_{net} + CP * CC}{AEP_{net}} \quad (3)$$

where:

- MP = marginal generation price (\$/MWh)
- AEP_{net} = net annual energy production (MWh/yr)
- CP = capacity payment (\$/MW/yr)
- CC = capacity credit (%).

Marginal generation price (MP) captures the marginal value of energy, which is multiplied by the AEP_{net} to yield the annual revenue from electricity production. The product of capacity payment (CP) and capacity credit (CC) yields the marginal value of capacity. For the purpose of this study, marginal generation price was represented by either locational marginal prices or market marginal costs (system lambdas) depending on data availability. The marginal generation price component of this approach takes into account projected electricity price increases during the lifetime of a renewable generation plant based on the EIA's *Annual Energy Outlook* (2015a) reference case price projections levelized to an effective present price. A capacity credit of 25% was assumed for offshore wind in this assessment based on land-based wind capacity credit estimates from Milligan and Porter (2008) because of the limited regional data for offshore wind at this point. Capacity payment is based on the overnight capital cost of a new advanced natural gas combustion turbine plant (EIA 2015a, Table 8.2). The calculation of AEP for LCOE and

¹⁹ These two LACE components—marginal generation price and capacity value—were applied to any electricity market found among U.S. coastal regions regardless of the type of electricity market (e.g., energy-only markets or capacity markets).

²⁰ In this analysis, 20 years were assumed for offshore wind project lifetime.

LACE is identical (see above). More details on the calculation of LACE are described in Brown et al. (2015).

3.3 Economic Potential

There are many ways to estimate the economic potential or viability of renewable energy projects (e.g., Massachusetts Institute of Technology 2015; Hirth 2013). For the purpose of this analysis, economic potential is defined as the capacity or generation that is associated with those sites in which LACE exceeds LCOE. This necessary condition for economic potential can be stated in terms of “net value” as shown in Eq. 1:

$$\text{Net value (\$/MWh)} = \text{LACE} - \text{LCOE} \quad (1)$$

Economic potential is the quantity of the technical resource potential associated with locations that have a net value greater than zero, indicating economic viability. Economic potential can be helpful as a high-level indicator to estimate the economic viability of new generation. It generally follows the approach and methodology from EIA (2013) and previous NREL analyses for land-based wind and solar photovoltaic (e.g., Brown et al. 2015).

3.4 Analysis Limitations

The metrics discussed in this section can inform the economic viability of offshore wind both individually and when compared to each other. A general limitation of the metrics as they have been applied in this study is that they are simplifications, which do not capture the entire set of considerations for actual deployment. Some other general limitations are listed below.

- To achieve the modeled cost reductions in the United States, a key assumption is that there will be continued investments in technology innovation, developments, and the market visibility of a robust domestic supply chain commensurate with the established European offshore wind supply chains during the analysis period from 2015–2027 (COD) and sustained domestic offshore wind development (DOE 2015; Navigant 2012; European Commission 2016). The cost-reduction pathway considered in this analysis will likely not be realized without sufficient domestic deployment. If the future market volume and outlook is uncertain, it is likely that costs will be higher than projected in this analysis. The model is not explicitly linked to specific deployment targets or supply chain maturity assumptions. Under the 86 GW projected by DOE’s *Wind Vision* (DOE 2015) study scenario, 2–3 GW of offshore wind deployment would be required annually until 2050. This level corresponds to present-day European deployment, but whether these deployment levels are sufficient for the U.S. supply chain to support the modeled cost reductions requires further analysis, which was not within the scope of this study.
- This analysis defines scenarios that assume that the U.S. offshore wind industry can leverage the recent European offshore wind technology and industry experiences while accounting for some significant physical, regulatory, and economic differences. The cost-reduction pathway under this scenario applies projected cost reductions developed for European projects, including sufficient learning and scaling effects and the development of U.S.-based labor skills and ocean-based infrastructure (e.g., assembly ports or vessels) (Navigant 2012; Valpy 2014; McClellan et al. 2015; Moné et al. 2015); however, the scope of the study did not

include a full analysis to convert European offshore wind market conditions to U.S. market conditions.

- Although the model assumptions are based on sound engineering and economic principals, we see this as a first step in a process to quantify cost reductions for offshore wind energy and to better understand the market opportunities for offshore wind in the United States.
- Domestic cost reductions similar to those predicted in Figure ES-2 will require additional activities to reduce risk and uncertainty of early projects, including addressing U.S.-specific challenges (e.g., hurricanes, deeper water, Jones Act requirements) and incentivizing markets (see, e.g., Smith, Stehly, and Musial [2015] and McClellan et al. [2015]).
- Because the analysis was conducted at a national scale, it contains a number of simplifications and uncertainties that may affect the accuracy of reported results at any individual location. These uncertainties fall into four primary categories: (1) models—parameter studies were conducted with first-order tools and do not reflect detailed design (e.g., the analysis deliberately does not consider the possible impacts of wake interactions among potential wind projects); (2) cost data—no commercial-scale offshore wind power project has commercial operation status at the time of this assessment, which makes it difficult to validate assumptions; (3) suitability/availability of technology—new components (e.g., dynamic high-voltage cables) and equipment will be needed to install projects in the range of site conditions considered in this analysis; and (4) macroeconomic factors (e.g., exchange rates, commodity prices).
- The analysis does not consider several significant design variables that may contribute to variability among regions. For example, surface ice exposure will limit accessibility during winter months for projects in the Great Lakes and may have potentially large impacts on operational expenditures and availability; surface ice floes may also necessitate structural modifications (e.g., ice cones).
- This analysis includes a preliminary assessment of LACE limited by available data and a set of simplifying assumptions. Further refinement—which could include the consideration of competition among technologies, dynamic feedbacks from increasing renewable deployment on wholesale electricity prices, and export or import situations—and new data could improve this indicator. LACE also does not consider policy-related factors or subsidies, either nationally or in individual states. These factors may include renewable energy support mechanisms (e.g., the production tax credit, carbon pollution and other greenhouse gas regulations, state renewable portfolio standards, and loan guarantee programs), energy sector and environmental regulations, or benefits from portfolio diversification (EIA 2015b).²¹ LACE is also not reduced as higher penetrations of renewable energy enter market regions over time or as changes occur in market structure.
- The calculation of economic potential should not be used to project actual deployment. Economic viability indicates that a site may be able to compete in the local energy market, but it does not guarantee that it will successfully be deployed.
- The analysis does not aim to precisely estimate costs or avoided costs at any one location. As noted above, in some cases, the analysis was constrained by the availability of GIS data,

²¹ Accelerated depreciation (MACRS) is considered

existing model capabilities, and simplifications necessary to process data. These limitations are described in detail in later sections. The time frame of the analysis considered only the period to 2027 (COD). Because some offshore wind technology is still in a nascent stage of development, the analysis period should be considered a near-term window, especially for floating technology. It is expected that the viability of offshore wind technology will continue to improve beyond the analysis window; therefore, economic viability may lag in some regions where the technology and costs mature later.

Beyond these general caveats, we provide a discussion below of some specific limitations that apply to LCOE, LACE, and economic potential, respectively.

3.4.1 Levelized Cost of Energy

The results of this assessment are subject to a number of limitations of which the reader should be aware before drawing conclusions. To conduct the analyses, a methodology was adopted that balances processing speed and fidelity. The emphasis is to develop solutions on a national scale that illustrate the relative differences in LCOE among potential sites rather than developing estimates that precisely describe the absolute LCOE value at a specific site. Further, analysts performed the spatial-economic assessment with existing cost models—without performing additional structural engineering analysis—and operated within the constraints of existing GIS data sets. As a result, a number of technical simplifications and assumptions were made that could have material implications on LCOE results.

The following important spatial variables that are likely to affect offshore wind power project design were not considered:

- **Icing.** Significant ice formations often develop in the Great Lakes region during the winter months. Icing imposes structural loads on the monopile and jacket substructures, which may require design changes, such as the addition of a conical ice cone to disperse loads. Ice coverage can also significantly reduce the ability of maintenance vessels to reach the project, which has implications on availability and OpEx. Results in the Great Lakes should be viewed with caution because they do not account for this major technical variable.
- **Hurricanes.** Hurricanes can occur in the Gulf of Mexico and Atlantic regions of the United States, with the probability of severe hurricanes prevalent in the South in particular. Although efforts are underway to develop hurricane-resilient designs and standards for offshore wind turbines, the implications on turbine and substructure design add uncertainty to the design process and may increase CapEx and insurance requirements beyond what the model now considers for turbines sited in these regions.
- **Extreme design conditions.** Variability in extreme wave height data could be a cost driver for offshore wind power projects. Variations in extreme wave heights will affect the hydrodynamic loading on the substructures, which could directly affect cost by the need to add steel or potentially affect the deck height/tower height requirements. Extreme wave height can also be important for mooring system design. At some sites, extreme currents could also be a major driver, and in some locations they could limit deployment options. A GIS data layer for extreme design conditions throughout the United States could be used to add another cost variable parameter, but this was not included for this study.

- **Sediment details.** BOEM’s national database on sea bottom conditions identifies sediment type, but it does not describe the sediment thickness or composition at elevations below the mud line. Also, this limited database covers only the Outer Continental Shelf (OCS) and does not include the Great Lakes region. The limitations associated with this geotechnical GIS data layer prevented the consideration of soil structure as a primary cost variable. This lack of data reduces our confidence in the mooring system cost estimates and likely underrepresents the variability that may exist from one location to another.
- **Wake interaction.** The analysis deliberately does not consider the possible impacts of wake interaction among potential wind projects.

The relationships among cost, performance, and spatial variables are simplified in many cases and possess some degree of uncertainty. These uncertainties fall into three categories. First, in many cases the cost relationships are derived from structural parameter studies using first-order design tools and approximations that do not fully capture the nuances of more rigorous engineering design methods. Second, cost multipliers are developed using best-available knowledge, but they are imperfect where knowledge gaps are present. A good example is that because no commercial-scale floating offshore wind power project has ever been installed, some cost and scaling assumptions were necessary.²² Third, in some cases the offshore wind application, which was adapted from current experience with European offshore wind and oil and gas, extends beyond industry experience. For example, the water depths and the severe metocean conditions found at locations in the Pacific Ocean may require new components and equipment (e.g., O&M vessels) that will be qualified and tested for successful installation and operation for the first time in the U.S. market. Further details about these specific limitations and uncertainties are indicated throughout the report and are described in detail in Appendix C.

Like any economic assessment, there is uncertainty because of macroeconomic factors, including exchange rate fluctuations, commodity price fluctuations, labor rates, supply and demand, and so on. Because this assessment focuses on identifying differences among sites, it does not make any attempt to quantify the potential impact of these factors; any changes in the macroeconomic situation are likely to affect projects within the U.S. offshore resource area relatively equally.

3.4.2 Levelized Avoided Cost of Energy

This analysis includes a preliminary assessment of LACE limited by available data and a set of simplifying assumptions. Further refinement—which could include the consideration of competition among technologies, dynamic feedbacks from increasing renewable deployment on wholesale electricity prices, export or import situations, and new data—could improve this indicator. The LACE components, such as electricity price and capacity value projections, are inherently uncertain. In particular, the LACE estimation developed for this analysis is based on annual averages and does not consider the probability of coincidence between the offshore wind production profiles and temporal patterns of marginal generation prices in specific offshore wind regions and the possible benefits that could potentially increase the capacity value as noted by AWS Truepower (Bailey 2015). In addition, the nationwide capacity credit of 25% assumed for offshore wind has been informed by land-based wind capacity credit estimates (Milligan and Porter 2008) because of the limited regional data for offshore wind at this point. Initial studies

²² Another example of an area for future improvement includes a careful analysis of interconnection and integration costs of offshore wind, which may vary from one region to another and may be highly project specific.

suggest that capacity credit varies significantly among U.S. coastal regions and that the assumption of 25% may likely be at the lower end of the possible range of capacity credit values found in U.S. coastal sites. For instance, estimated capacity values for offshore wind range from 24% for California (Stoutenburg, Jenkins, and Jacobson 2010) to 40% for New York (Ensslin et al. 2008). An analysis from GE Energy (2010) estimated the 3-year average capacity value for offshore wind in the Independent System Operator–New England territory to range from 47% to 51% in a scenario with the best-suited wind sites available for development. Further research can provide a more detailed assessment of the spatial variation in offshore wind capacity value among U.S. coastal regions.

LACE also does not consider policy-related factors or subsidies, either nationally or in individual states. These factors may include renewable energy support mechanisms (e.g., the production tax credit, carbon pollution and other greenhouse gas regulations, state renewable portfolio standards, and loan guarantee programs), energy sector and environmental regulations, or benefits from portfolio diversification (EIA 2015).

3.4.3 Economic Potential

The economic potential metric applied in this analysis is generally simpler and offers greater transparency than market models that employ more sophisticated techniques such as optimization (Brown et al. 2015). The method described is under active development and may be updated to reflect improved understanding of any of the various factors affecting economic potential. Some general caveats specific to LCOE and LACE are mentioned in Section 3.4.1 and Section 3.4.2 and discussed in greater detail in Brown et al. (2015). An important caveat that applies to the interpretation of economic potential as it relates to this analysis is the focus on only one technology for a comparison of offshore wind LCOE to LACE. A more comprehensive assessment, which was beyond the scope of this study, would consider not only the LACE/LCOE difference from offshore wind but also this difference to other available technologies to determine which technology can provide the highest system value at the lowest cost.

4 Spatial Characteristics of the U.S. Offshore Technical Resource Area

This section provides an overview of the U.S. technical resource area. Geographic data was obtained from several publicly available and commercially licensed data sets. Analysts normalized these source layers to spatially align them with the generic wind power plant grid (see Section 3.1) and processed them to create the layers that are necessary to calculate wind power plant cost and performance. Table 3 summarizes the data layers used in this analysis. Appendix A describes each of the input layers and processing steps in detail. Figure 16 (presented in Section 6) illustrates the process by which the data from each GIS layer flows through cost and performance models to generate results.

Table 3. Summary of Spatial Data Layers

GIS Layer Name	Sources	Notes on Application within this Report
Wind Resource Grid	AWS Truepower, Modern Era Retrospective Analysis for Research and Applications, National Buoy Data Center	Gridded 2-km wind speed/direction shape files checked against data from the Modern Era Retrospective Analysis for Research and Applications and National Buoy Data Center, processed to the uniform Universal Transverse Mercator grid; wind resource grid enables AEP calculations at each potential project
Wind Power Plant Grid	NREL	Turbine specifications combined with NREL layout assumptions; wind project grid enables AEP calculation and filtering of results
Distance from Cable Landfall	ABB Energy Velocity Suite	Existing electric grid features; enables calculation of distance to interconnection and grid upgrade costs
Bathymetry	National Oceanic and Atmospheric Administration /BOEM	National Oceanic and Atmospheric Administration bathymetry data at different resolutions combined to create composite continuous bathymetry layer; defines water depth
Logistical Distances	World Port Index	Logistical nodes including staging ports and inshore assembly areas; allows identification of relevant installation distances and O&M distances
Installation Met-Ocean Layer	U.S. Army Corps of Engineers/ NREL	Weather data processed at nonexceedance limits of 2.5 m significant wave height (Hs) and 16 m/s significant wind velocity (Ws) for floating substructures, 2 m Hs and 12 m/s Ws for fixed substructures, and 1 m Hs and 8 m/s Ws for Jones Act compliance; results in installation weather downtime estimates at each potential project
O&M Met-Ocean Layer	U.S. Army Corps of Engineers/ NREL	Assigns each potential project to one of three representative sites—mild, moderate, and severe—with associated time-series metocean data for the O&M parameter study
Regional CapEx Multipliers	Science Applications	Accounts for expected regional differences in wind project CapEx (e.g., labor rates, freight costs); applied as an adder to CapEx

	International Corporation ^a	
Regional Transmission Multipliers	NREL (ReEDS) ^b	Accounts for expected regional differences in transmission CapEx (e.g., population density); applied as an adder to grid connection CapEx
<p>^a Note: These layers are not included in Section 3. Detailed information can be found in Appendix A.</p> <p>^b Regional Energy Deployment System</p>		

4.1 Wind Characteristics

Understanding the wind resource is vital to offshore wind power projects because it determines how much energy can be produced at a location. Because the offshore wind resource determines the AEP at a particular site, the wind resource plays a central role in assessing economic viability. Figure 7 shows the variation in average annual wind speed among the offshore regions at 100 m above sea level. At the time of this study, the existing data provided by AWS Truepower was limited to within 50 nm. To approximate ocean wind speeds between 50 nm–200 nm, the data at the 50-nm boundary were linearly extended using a nearest-neighbor technique (DOE 2015). Because wind speeds are expected to continue to increase between 50 nm–200 nm, this technique likely underestimates the wind speeds in the farther regions.

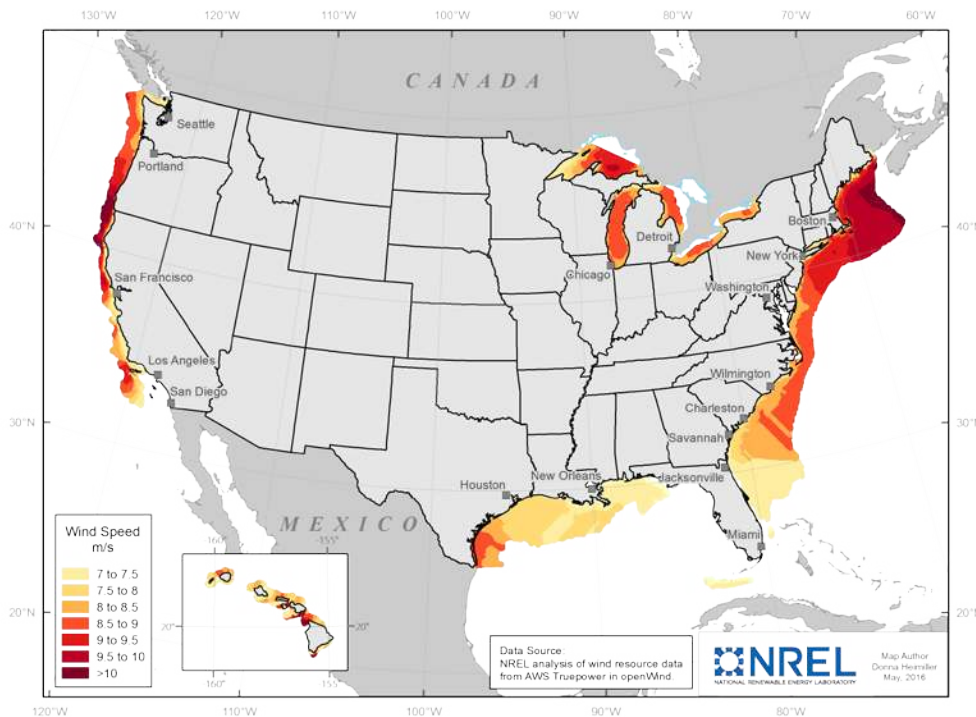


Figure 7. U.S. annual average wind speeds (at a height 100 m above the surface, 200 nm from shore, and depths up to 1,000 m; annual average wind speeds >7 m/s)²³

²³ At the time this analysis was completed, an extension of the resource data to the U.S. exclusive economic zone boundary had not yet been completed. A parallel resource assessment study, however, used the Wind Integration

Within the zone from 0 nm–50 nm, annual mean wind speeds are generally higher as the distance from shore increases, with the highest wind speeds found in the mid-Pacific, North Atlantic, northern Great Lakes, and Maui Channel off the island of Hawaii.

The North Atlantic has a very strong offshore wind resource, with average annual wind speeds between 9 m/s–10 m/s. Wind speeds gradually diminish from the north southward in the Atlantic. However, annual average wind speeds exceeding 8 m/s can be found at locations that are far from shore as well as areas toward the western edge of the Gulf of Mexico. Hurricane exposure is a significant concern in these latitudes, but each project location must be evaluated individually because the characteristics of these storms depend significantly on the coastal geography (Musial and Ram 2010).

The Pacific Coast has a strong offshore wind resource extending from the Channel Islands north to Seattle. Peak wind speeds approach 10 m/s near the border of Oregon and California. However, the area to the south of the Channel Islands displays some of the least energetic wind in the U.S. offshore resource area. In the Great Lakes region there is a strong wind resource, which improves in the northern lakes and with the distance to shore.

Wind direction is important to consider because it has implications for energy production and the optimal plant layout within each region. Figure 8 shows representative wind direction profiles in the form of wind frequency roses for each region. The frequency of wind speed content from a particular direction can be determined by examining the length of the individual spokes within each wind rose: the longer the spoke, the more frequent the wind comes from that direction.

National Dataset Toolkit data to determine wind speeds in offshore areas from 50 nm–200 nm, giving more realistic resource patterns in the farther offshore regions (Musial et al. 2016).

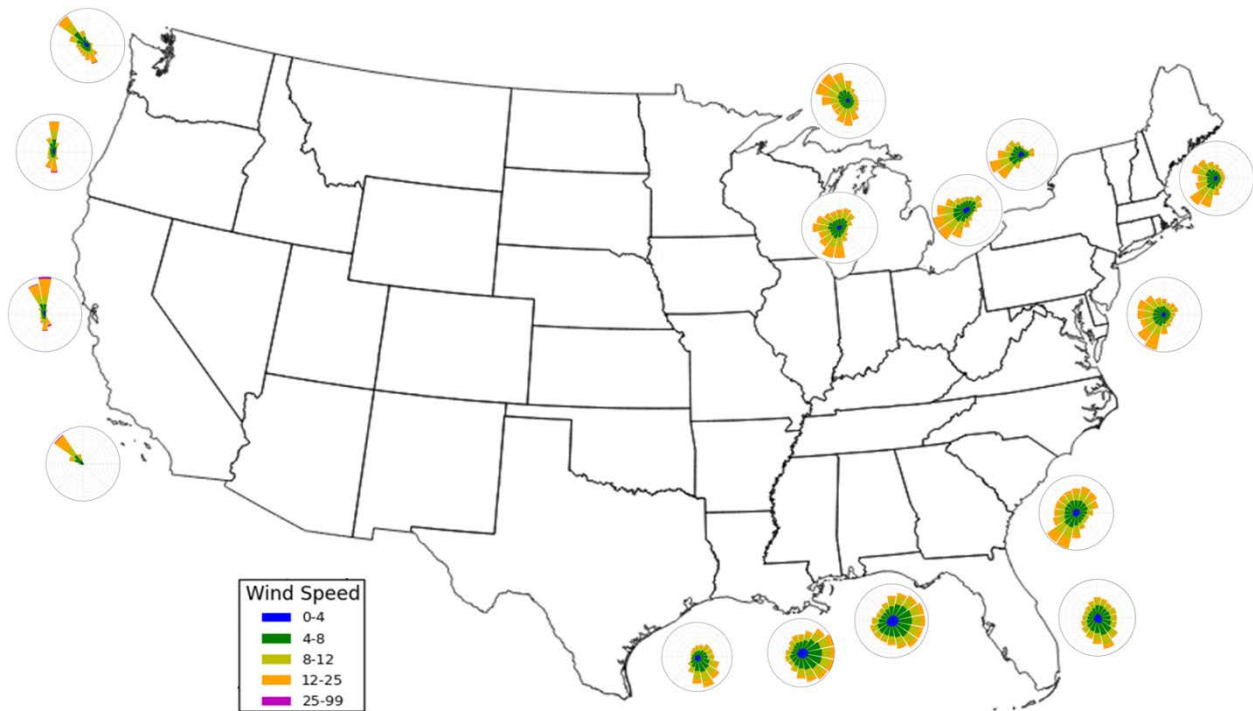


Figure 8. U.S. offshore wind speed and direction during a 1-year period. Image from NREL analysis based on data from AWS Truepower, Modern Era Retrospective Analysis for Research and Applications, and the National Buoy Data Center

Wind direction varies considerably among the offshore resource areas, but the regions do have distinct trends. The strongest winds in the Atlantic typically come from the southwest, typically running parallel with the direction of the coastal geography. In the Gulf of Mexico, winds have a strong easterly component, but they exhibit a high degree of variability. The Great Lakes encounter the strongest winds from the northwest through southwest, following the jet stream. The Pacific winds exhibit a high level of uniformity, with winds almost exclusively following a single direction, typically from the northwest parallel to the coastline. Again, the exact directional heading depends on latitude and coastal geography.

4.2 Bathymetry

Bathymetry is the primary parameter that influences the selection of a substructure technology for each offshore wind power project location. Consistent with the technical resource area as defined in Musial et al. (2016), water depths of up to 1,000 m are considered in this analysis, except for the Great Lakes region where water depths greater than 60 m were excluded because of potential ice floes; this analysis assumed that water depths greater than 60 m would not be economically feasible with existing fixed-bottom technology, and therefore they were excluded from the final analysis.

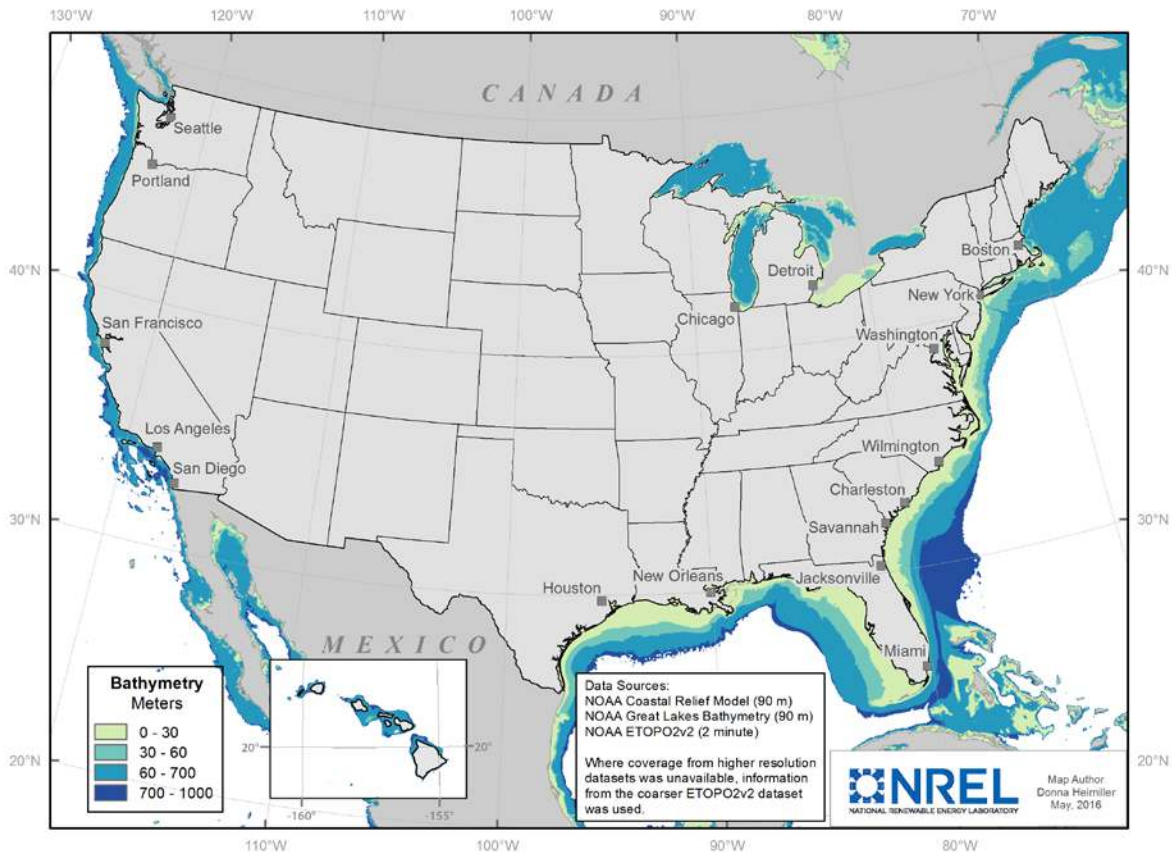


Figure 9. U.S. bathymetry map

Figure 9 shows that there is a great deal of variance in water depths among the U.S. offshore regions, particularly when comparing the eastern United States to the western. For instance, the Atlantic and Gulf Coast regions have a large continental shelf characterized by shallow water depths far from the shoreline and extending out well past the 100-nm mark in most areas. In contrast, the bathymetry of the Pacific and Hawaiian coasts drops off much more dramatically closer to the shoreline. Therefore, less area on the West Coast and Hawaii is captured within the 1,000-m-depth threshold. The Great Lakes have relatively shallow water depths overall, with many areas between 0 m–60 m.

4.3 Logistics

To estimate the sensitivity of installation and O&M costs to distance, a data layer was developed that identifies locations that may be suitable to support these operations. Ports provide facilities for the receipt, storage, assembly, and load-out of components during installation. The ports can also serve as the O&M base from which the operator coordinates maintenance and repair operations. The World Port Index applied basic filters, including the channel depth, degree of shelter, and unrestricted access to the offshore resource area. In practice, suitability will depend on a number of other considerations, including but not limited to existing infrastructure (alternatively, required upgrades), vertical/horizontal clearance limits, and competing port uses.

Staging ports areas are necessary to support the assembly and installation of offshore wind units. Many of these ports would likely require infrastructure investments to support large-scale offshore wind deployment. The cost of this investment is not considered in this analysis because the analysis does not attempt to represent a specific deployment scenario.²⁴ This analysis distinguishes between staging ports that have overhead restrictions and those that do not. Current semisubmersible technologies and future technologies that load out with the turbine fully integrated to the substructure in port will need to deploy from ports that do not have overhead clearance restrictions.

Figure 10 shows relevant logistical points that could support installation and operations for projects. Staging ports have been distinguished by whether they have any clearance limits, which would limit the deployment of semisubmersible substructure technology, and where the turbine would be installed and commissioned at quayside before being towed to the site for hookup to a preinstalled mooring system.

²⁴ An estimation of these costs would require specific assessments of current infrastructure, the identification of gaps at each port, and the costs of improvements. It would also require the development of assumptions about which ports are upgraded to support offshore wind deployment as well as how the upgrade costs are spread among the projects that the port would be expected to support.

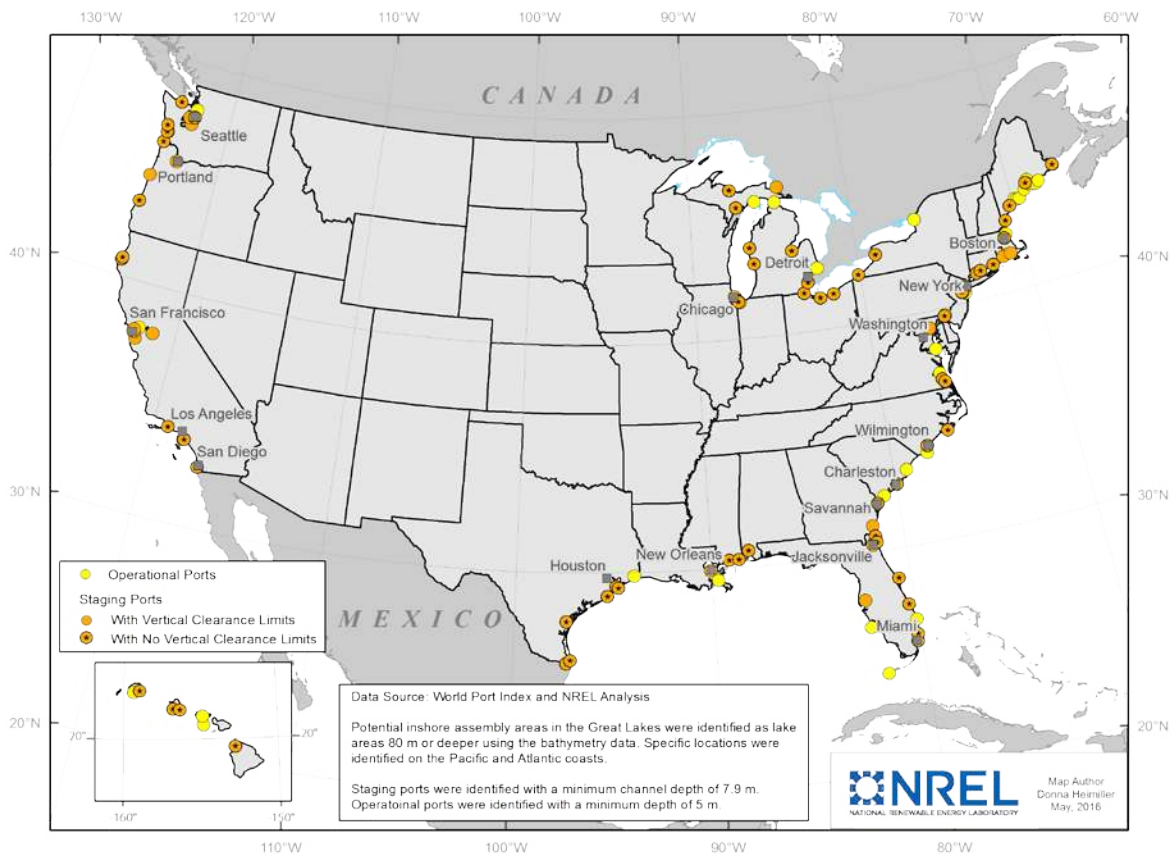


Figure 10. Operational and staging ports (with and without clearance limits)

4.4 Metocean Conditions

Metocean conditions vary considerably among project sites within the U.S. offshore resource area, and they can influence installation CapEx, OpEx, and the technical availability of the project. For this study, we assessed national hindcast data sets of wind speed and significant wave height to identify the proportion of time when operational thresholds for various marine operations might be exceeded. More information about how these data were processed to inform the calculation of installation costs and operational costs can be found in Appendix A.

All lifting operations for projects using floating offshore wind technology are assumed to occur at a staging port in sheltered waters. The marine operations therefore have a limited sensitivity to wind speed relative to fixed-bottom offshore wind power projects. Although considered jointly with wind speed, the primary factor to determining whether downtime is significant is wave height.²⁵ Figure 11 shows the variability in significant wave height throughout the U.S. offshore resource area (Electric Power Research Institute 2011).

²⁵ Note that the consideration of other parameters beyond wind speed and significant wave height (e.g., wave period, wave direction, and current) is essential for developing realistic marine operation plans for a given site. These other metocean parameters are not considered in this assessment because of the additional data processing required.

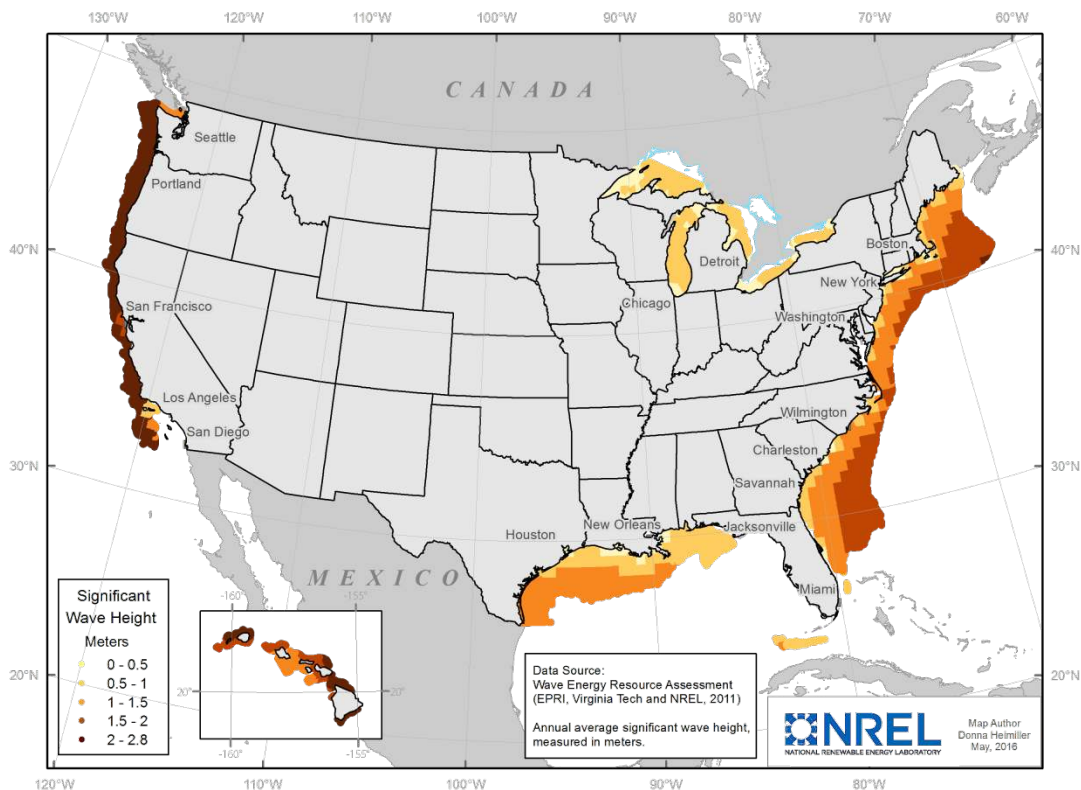


Figure 11. Average significant wave height

Figure 11 shows that yearly average significant wave heights generally increase with distance from shore. It is also apparent that the metocean conditions on the West Coast and Hawaii are more severe than those in the Atlantic or Gulf of Mexico, with significant wave heights exceeding 2 m across most of the West Coast region and 1.5 m across most of the Hawaii region. Metocean conditions in the Great Lakes are mild compared to those in offshore locations, with significant wave heights reaching less than 1 m throughout the entire region.

4.5 Competing Use and Environmentally Sensitive Areas

Competing uses and environmentally sensitive areas account for a significant fraction of the coastal waters in the United States. Consequently, the offshore wind resource has a large number of stakeholders, which reflects its importance for conservation, commerce, recreation, and defense. It is therefore reasonable to assume that the areas available for offshore wind development will be limited to some extent by these considerations. Limits might be defined by legislation, marine spatial planning, or simply by the unwillingness of offshore wind developers to pursue sites where stakeholder opposition is high.

In 2009, NREL commissioned Black & Veatch (2010) to identify areas where competing ocean uses and environmental sensitivities may exist in the U.S. offshore wind resource area. Figure 12 shows the resulting GIS layers, which include areas with environmental and wildlife concerns,

offshore oil and gas platforms and pipelines, commercial fisheries, military use areas, cultural and historic areas, and social and recreational impacts.

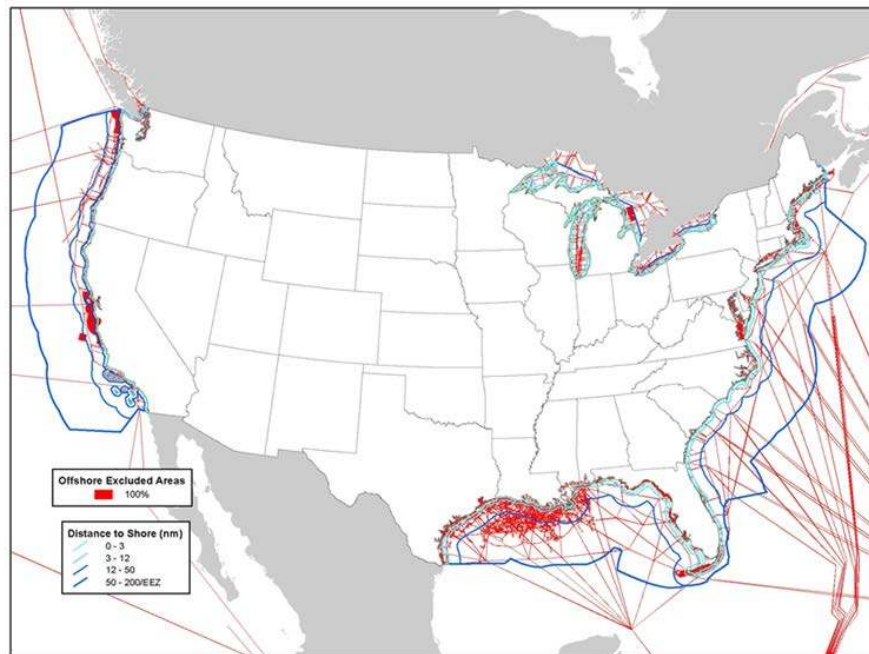


Figure 12. Estimated excluded areas due to competing use and environmental exclusions. *Image from Black & Veatch (2010)*

Further analysis was conducted to assess the competing use and environmentally sensitive area exclusions shown in Figure 12 as a function of distance to shore. The shares of competing use and environmentally sensitive areas by distance from shore are shown in Table 4. These competing layers are not a comprehensive set of all potential conflicts, however. For example, high-density avian flyways and visibility from tourist areas with high economic value were not included in the Black & Veatch (2010) data set. As such, the Black & Veatch (2010) percentages may not include all exclusions that would likely be required during a more rigorous marine spatial planning process, and it is likely these percentages may increase under more detailed analysis with full stakeholder participation. To remain conservative in estimating LCOE, further reductions were assumed to account for visual impacts and other possible conflicts near shore.

The right column in Table 5 indicates the percentage of exclusions that were assumed due to competing use and environmentally sensitive areas for this study.

Table 4. Competing Use and Environmentally Sensitive Area Spatial Exclusion Layer

Distance from Shore (nm)	Black & Veatch (2010) Exclusion (%)	Exclusion Applied for this Study (%)
0–3	48	99
3–12	38	90
12–50	21	40
50–200 (Exclusive 8 Economic Zone)		40

5 Wind Power Plant Performance Modeling

To characterize performance, the U.S. offshore resource area was segmented into 7,823 distinct wind power plant layouts of 600 MW each. Analysts developed a new code for Openwind, a software package from AWS Truepower that enables it to automatically process wind resource grid data throughout the entire U.S. offshore resource area. This automated process yields wind power plant performance results for each wind project location. These results, including gross AEP and wake losses, are fed into the data processing framework and enable the calculation of site-specific LCOE.

This section provides a high-level overview of the wind power plant performance modeling methodology. Appendix B provides a more detailed technical description of the process and assumptions.

5.1 Conceptual 600-MW Array Model

Assumptions for a conceptual offshore wind power project were defined to evaluate the energy capture potential and deployment capacity potential of the resource area at discrete offshore sites. This conceptual project consists of 100 generic 6-MW turbines with a 155-m rotor. The turbines are laid out in a 10-by-10 grid and spaced at 7 rotor diameters, or 1,085 m, with a wind power plant side length of 10,850 m corresponding to an area of 117 km². Figure 13 shows a schematic of this layout. Actual wind power plant deployment would optimize the layout based on wake losses; the conceptual project layout was chosen to simplify the analysis, but the authors acknowledge that wake losses from this design would likely be higher than in practice.

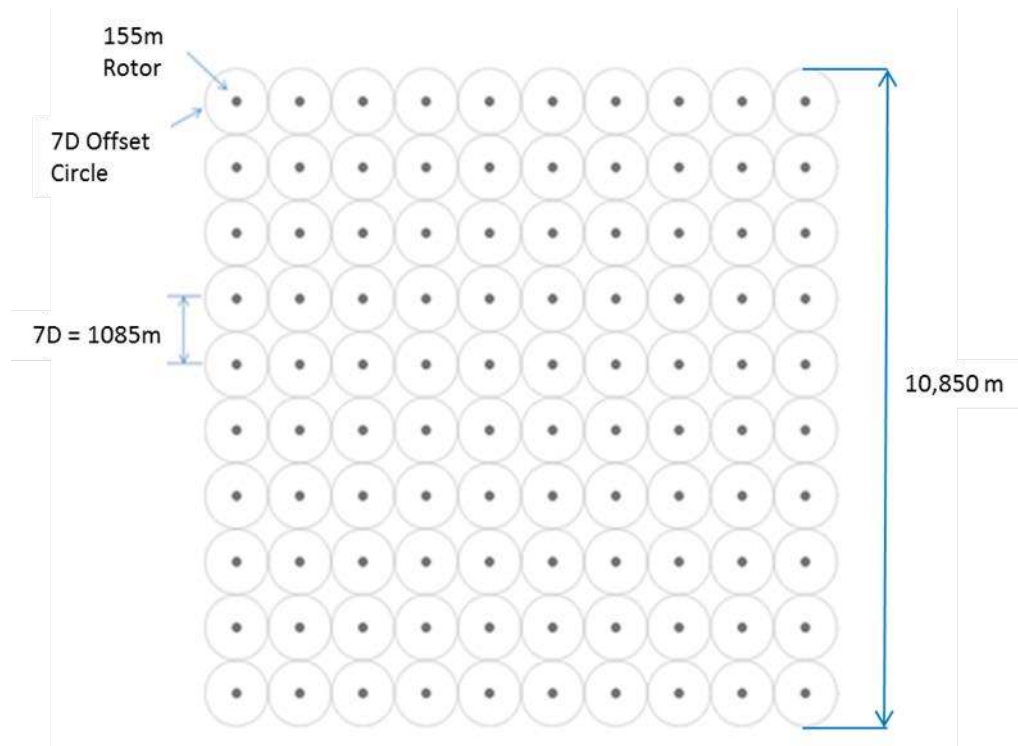


Figure 13. Conceptual project layout with 100 generic 6-MW turbines

The array density of the conceptual wind power plant is 5.1 MW/km², which is approximately 70% higher than the array density assumed in the resource assessments performed by NREL of 3 MW/km² (Musial et al. 2016). It also can be compared to the mean array density of 6.1 MW/km² of 19 operating offshore wind power projects in Europe that have capacities greater than 200 MW, as shown in Figure 14 by the dashed red line.

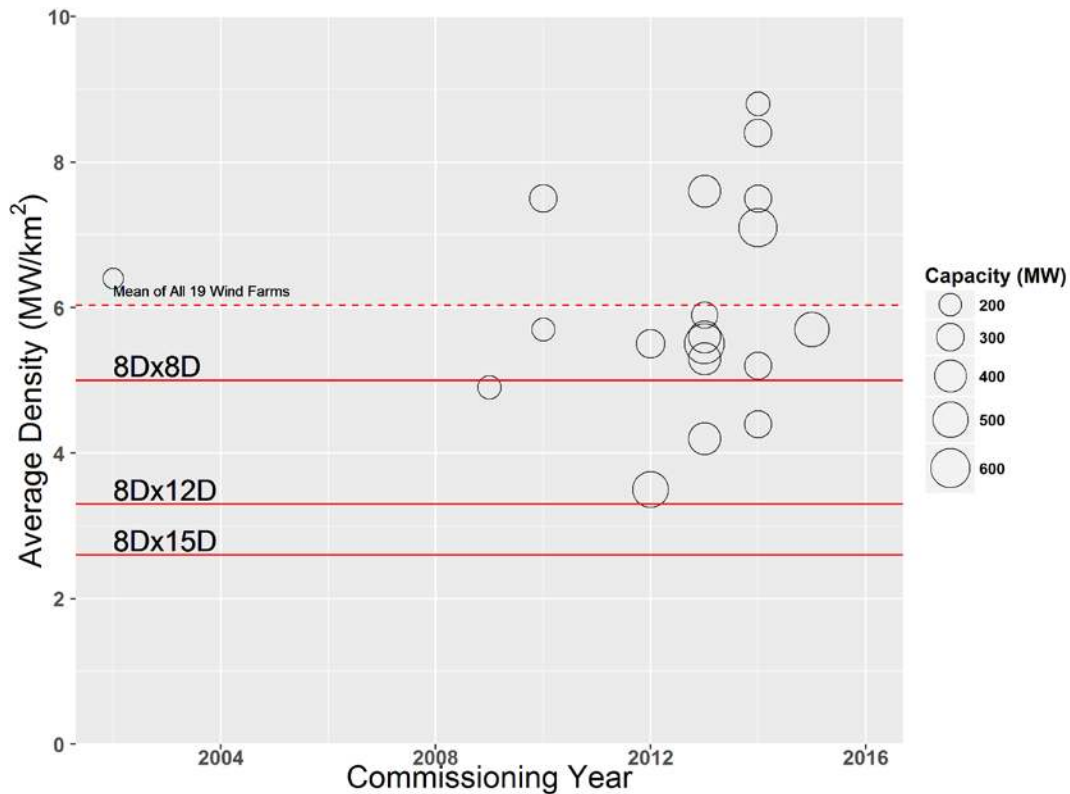


Figure 14. Average turbine array density for 19 European offshore wind power projects. Image from Musial et al. (2013)

5.2 Openwind Simulations

Performance was modeled using Openwind Enterprise, a wind energy facility design tool created by AWS Truepower and licensed to NREL. The software can perform layout design, flow modeling, wake modeling, and energy assessment, and it is intended for commercial applications. Openwind Enterprise was selected for its high degree of interoperability with GIS data as well as its capability to model deep-array wake effects.

The Deep Array Wake Model in Openwind Enterprise was selected to evaluate wake losses within each project. Although there is still a large degree of uncertainty associated with wake modeling, the Openwind Deep Array Wake Model is one of the most widely used and accepted tools in the industry.²⁶ NREL's prior analysis (mostly with land-based wind projects) indicates

²⁶ Models based on computational fluid dynamics, such as the Simulator for On/Offshore Wind Farm Applications, are currently under development and may offer a higher degree of accuracy than the Deep Array Wake Model; however, computational fluid dynamics models are too computationally expensive for this large-scale analysis. For the purposes of this study, Openwind has the appropriate level of fidelity.

that the Openwind Deep Array Wake Model performs as well or better than other similar commercially available models.

A GIS layer was developed that successively places these conceptual wind projects in a grid that provides seamless (but not overlapping) coverage of the U.S. offshore technical resource area. As such, the analysis deliberately does not consider the possible impacts of wake interaction among potential wind projects. Figure 15 shows this area covered by the Openwind analysis. The original computation of AEP was conducted using a proprietary 6-MW power curve. For this report, these proprietary AEP values were adjusted to match the performance of a similar NREL-modeled, generic 6-MW offshore wind turbine with a rotor diameter of 155 m and a hub height of 100 m. AEP values were recalculated for a decimated sample of approximately 200 wind power plant layouts using the generic machine, which was used to perform a linear transformation of the proprietary power curve AEP based on wind speed to obtain the AEP values of the generic wind turbine at all locations inside the Openwind analysis domain.

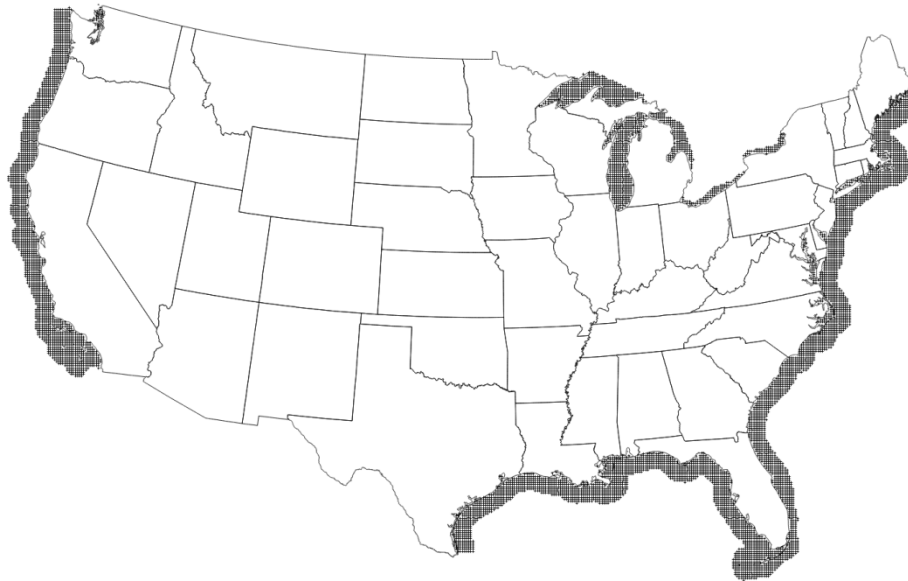


Figure 15. Using Openwind, 7,159-unit wind power plants were modeled throughout the resource area of the continental United States from 0 nm–50 nm

Even though Openwind has the capability to apply losses comprehensively, availability and electrical losses were modeled externally from it to allow for a more robust and transparent loss model. These parameters are intrinsically linked to O&M strategy (availability) and electrical system design (electrical losses), both of which are driven by other spatial variables. Section 6 describes the derivation of these relationships.

Wake losses were modeled in Openwind using the Deep Array Wake Model. The product of other losses—including low- and high-temperature shutdown, icing, hysteresis, and lightning—were assumed to multiply to a total of 2% of lost energy production.

Openwind was used to generate the AEP and wake loss values on a geospatial grid covering the U.S. Outer Continental Shelf from 0 nm–50 nm. A script was created that commanded Openwind to automatically process the 7,159 wind power plant layouts. This code places

individual layouts at each of their specified locations on the GIS grid for the United States outer continental shelf and then evaluates the wind power plant performance at each potential wind site. Openwind computes performance as if the wind power plant were the only project in the region; wake interference among projects is deliberately excluded from this analysis. Openwind evaluates each project without any further optimization of the turbine layout. As a result, the modeled wake losses are likely more pronounced, on average, than those that would be experienced for real projects, in which the layout geometries would be optimized with respect to the local wind resource conditions.

Further details about the process for automating Openwind can be found in Appendix B.

6 Wind Power Plant Cost Modeling

Section 3 provides an overview of the general approach and methodology for the spatial-temporal cost assessment. This section provides details about the cost derivation and assumptions related to the main cost components, and it focuses on describing the methodology and results of the cost functions derived in a set of parameter studies. The data and assumptions for this report were derived from a combination of market reports (e.g., Moné et al. [2015]; Smith, Stehly, and Musial [2015]), cost-reduction pathway studies (e.g., Valpy et al. [2014]; Catapult [2015]; E.C. Harris [2012]; The Crown Estate [2012]; The Crown Estate [2015]), spatial data layers (see Table 5), and industry collaboration. Figure 16 shows the process by which each spatial GIS layer flows through cost and performance models to generate results. As indicated above, the cost assessment is based on an NREL-modeled, generic 6-MW offshore wind turbine. All costs, unless otherwise noted, represent U.S. dollars (USD) in 2015.

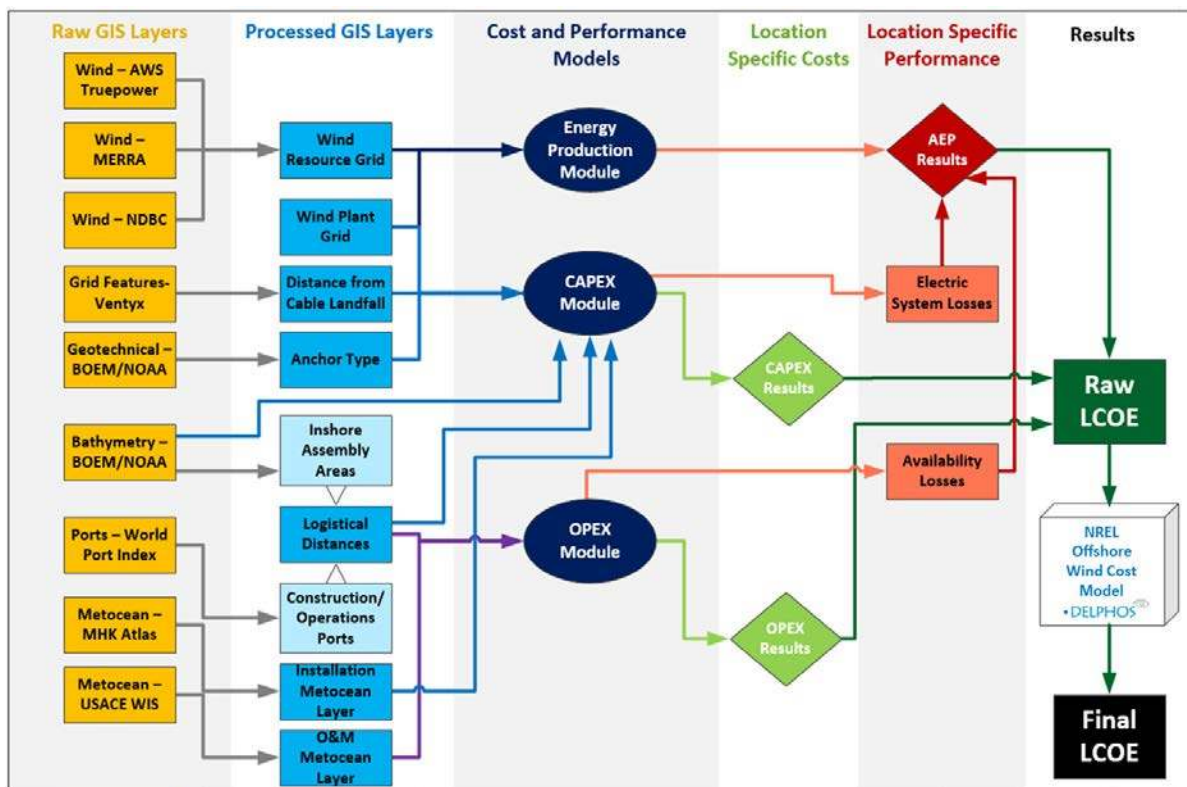


Figure 16. Spatial-economic assessment analysis

Table 5 summarizes the major cost categories associated with offshore wind power projects for the cost categories introduced in Section 3: fixed costs, variable costs, and cost multipliers.

Table 5. Cost Categorizes for Spatial-Economic Assessment

Cost Category	Type	Cost (\$/kW)^a	Comments
Turbine	CapEx	\$1,583	NREL-modeled, generic 6-MW turbine
Development	CapEx	\$196	NREL-modeled, generic 6-MW turbine
Ports and Staging	CapEx	\$25	NREL-modeled, generic 6-MW turbine
Operations	OpEx	\$31	NREL-modeled, generic 6-MW turbine
Substructure	CapEx	Variable	Cost dependent on water depth
Assembly and Installation	CapEx	Variable	Cost dependent on logistical distances, water depth, and metocean regime
Electric System	CapEx	Variable	Cost dependent on distance to cable landfall, water depth, and existing grid features
Maintenance	OpEx	Variable	Cost dependent on logistical distances and metocean regime
Engineering and Management	CapEx	Multiplier	3.5% multiplier applied to fixed + variable CapEx
Insurance	CapEx	Multiplier	1% multiplier applied to fixed + variable CapEx
Commissioning	CapEx	Multiplier	1% multiplier applied to fixed + variable CapEx
Contingency	CapEx	Multiplier	30% of installation CapEx; 5% of other CapEx
Construction Insurance	CapEx	Multiplier	1% multiplier applied to fixed + variable costs
Carrying Charges during Construction	CapEx	Multiplier	Calculated; CapEx schedule assumes 20% paid in year -2, 40% paid in year -1, and 40% paid in year 0
Decommissioning Fund	CapEx	Multiplier	65% of installation CapEx

^a All dollars are reported in USD (2015), if not indicated otherwise.

A total of 8,356 wind power plant grid cells are within the boundaries of this assessment.



Figure 17. Wind project grid for the northeastern United States and Great Lakes regions (each region represents a potential offshore wind power project)

This wind power plant layer is used as the basis for energy performance and economic modeling, and it defines the relevant spatial parameters for each potential offshore wind power project location.

6.1 Fixed Costs

The fixed-cost category encompasses the cost items that do not have clear, empirical linkages to spatial parameters based on current knowledge and market context. The data that informed the calculation of these fixed-cost assumptions were derived from a combination of market reports (e.g., Smith, Stehly, and Musial [2015], Moné et al. [2015];), cost component reports (e.g., GL Garrad Hassan [2013]; The Crown Estate [2012, 2015]), recent press statements, and industry collaboration.

6.1.1 Turbine Capital Expenditures

This assessment is based on an NREL-modeled, generic 6-MW offshore wind turbine in 2022 COD (2020 FC). Analysts estimated that a 100-unit order would be priced at approximately \$9.5 million per turbine or \$1,583 per kilowatt (kW), including a 5-year warranty provision and delivery from the turbine manufacturer to the staging port. This estimate for the NREL-modeled, 6-MW turbine CapEx is derived from Smith, Stehly, and Musial (2015) and reflects USD (2015) and 2015 currency exchange rates. The turbine capital costs for the 3.4-MW (2015 COD) and 10-MW (2027 COD) turbines were derived based on these estimated costs of the generic 6-MW NREL turbine and scaling relationships derived from the Crown Estate (2012).

This assessment assumes that wind turbine supply agreement prices are independent of the physical characteristics of a given project site. In practice, however, wind turbine manufacturers hold liabilities associated with warranty provisions and may adjust the pricing structure for a given site to account for the level of the perceived risk associated with exposure to environmental conditions or other technologies used within the project.

Turbine transportation costs are included within the turbine supply agreement price. This assessment does not account for differences in wind turbine generator transportation costs that

may be associated with different sites. Based on recent market activity, NREL analysts expect that initially turbine original equipment manufacturers will fabricate wind turbine components at European facilities and ship them to U.S project sites. This situation is expected to change as the U.S. market matures and as projects emerge in regions that are logistically difficult to reach from Europe. NREL analysts expect that, subject to market outlook, turbine original equipment manufacturers will build new fabrication facilities to serve these locations for components that are difficult to transport (e.g., blades, towers), provided that sufficient deployment exists to support these supply chains. It could be argued that transportation costs may decrease as a higher content of components is produced domestically over time. At present, however, it is difficult to predict where fabrication facilities will be built; therefore, the analysis excludes any attempt to capture variability in turbine transportation costs.

6.1.2 Development

Development costs for offshore wind power projects can be segmented into four main categories: engineering, permitting, site characterization, and decommissioning assessment. Engineering costs include a pre-front-end engineering design study to inform permitting applications. A full study of this nature is typically conducted to inform procurement, and grid connection studies can be used to determine interconnection requirements (e.g., land-based substation and transmission line upgrades). Permitting costs encompass those efforts required to negotiate leases and obtain environmental permits, including environmental surveys, environmental impact studies, and public consultations. Site characterization costs include the collection and analysis of geophysical and geotechnical data, wind resource data,²⁷ and ocean data. The decommissioning assessment generally includes detailed analyses to estimate all costs associated with returning the project site to its original state before wind plant operations began. The party responsible for decommissioning is specified in the original site lease and assumes decommissioning responsibility will be transferred if a change of ownership takes place. Specific conditions for decommissioning will be set by the sea area owner but are expected to follow the above ideology. Although these costs are generally relatively low as a percentage of CapEx, they occur early in the life cycle (e.g., before financial close) and can have a large impact on the viability of the project.

NREL analysts estimated that the development costs for a 600-MW project would amount to approximately \$117 million, or \$196 dollars/kW based on available industry information that suggests this cost item comprises approximately 4% of combined balance of systems (BOS) and turbine capital costs. Although development costs have exhibited significant variability for offshore wind power projects in Europe, much of them have been driven by regulatory considerations and/or public opposition rather than by the physical or technical conditions at the project site. These costs are assumed constant in this analysis because there is not a clear relationship between physical site conditions and development costs.

6.1.3 Port and Staging

Port and staging costs cover the activities and equipment needed at the local staging port to receive and store components from suppliers. Typically, port and staging costs for offshore wind power projects include the costs of renting space for equipment storage, the use of port cranes

²⁷ Note that site resource characterization for floating offshore wind projects may depend on the successful validation of floating lidar technology that can produce bankable performance data.

and equipment, and port fees incurred by installation vessels (e.g., entrance/exit, dockage, loading/unloading). Essentially, this cost category represents assembly activities that occur on land or at the quayside.

NREL analysts estimated that port and staging costs for a 600-MW project could be approximately \$25 million. These costs are assumed constant in this assessment because of the small impact of ports and the difficulties of accurately predicting costs. These costs were derived based on NREL's internal offshore BOS cost model.

Industry information suggests that nearly any port will require upgrades in the range of tens to hundreds of millions of U.S. dollars to efficiently support industrial-scale offshore wind deployment. Accurately identifying the cost of these upgrades would require a detailed gap analysis of each individual port, which is beyond the scope of this analysis. The allocation of responsibility for these capital improvements is also unclear and might vary from project to another (e.g., federal, state, and/or local government agencies are likely to fund port improvements to attract economic development).

The remainder of this section summarizes cost multipliers and the parameter studies conducted for this analysis. The parameter studies were conducted to derive relationships among variable costs and spatial parameters. The four cost parameter studies cover substructure, electrical infrastructure, assembly and installation, and O&M. Details about fixed-cost assumptions and cost multipliers can be found in Appendix C, which also includes an expanded discussion of the parameter studies.

6.2 Cost Multipliers

Some cost categories are estimated as a percentage of other cost line items. These costs are expected to change and are not explicitly linked to individual spatial factors, but they tend to vary to reflect the complexity of other items. The CapEx factors summarized in Table 6 below are mostly based on industry information provided and NREL's offshore BOS cost model.

Table 6. Summary of Cost multipliers

Category	Description	Factor	Applies to:
Engineering and Management	Engineering and management costs incurred from financial close through commercial operations	3.5%	All CapEx
Insurance During Construction	All risk property, delays in start-up, third-party liability, and brokers fees	1%	All CapEx
Commissioning	Costs to integrate and commission the project	1%	All CapEx
Installation Contingency	-	30%	Installation CapEx
Procurement Contingency	-	5%	Noninstallation CapEx
Decommissioning	Surety bond lease to ensure that the burden for removing offshore structures at the end of their useful life does not fall on taxpayers ²⁸	15%	Installation CapEx

Construction finance costs are added to the overnight capital cost based on assumptions about the construction expenditure schedule. Wind power plant construction finance is split 40%, 40%, and 20% during a 2-year period (40% assumed upfront, 40% after the first year, and the remaining 20% after the second year). Construction periods vary for other technologies, ranging from 0–6 years.

6.3 Variable Costs

This section presents variable cost components, which have distinct relationships with spatial parameters. A series of parameter studies were conducted to derive these variable cost relationships. A detailed description of the methodology and assumption applied to derive these relationships are provided in Appendix C.

6.3.1 Substructure Parameter Study

The substructure parameter study investigated how the primary substructure components vary with respect to environmental and turbine parameters. The study was conducted for two fixed-bottom (monopile and jacket) and two floating (semisubmersible and spar buoy) substructures. This section outlines the methodology used to arrive at the minimal overall substructure mass, which is assumed to be directly related to cost in this study.

The parameter study uses three generic turbines (3 MW, 6 MW, and 10 MW), which are described in Appendix A. Nine representative sites were considered; they are listed in Table 7 together with water depths and key metocean parameters.

²⁸ This estimate does not include any potential residual value attached to assets that could be sold or reused at the end of the project's operating life.

Table 7. Site Metocean Parameters

Site Name	Depth (m)	50Y-Hs (m)	50Y-Hmax (m)	50Y-Tp (s)	Monopile	Jacket	Semi-	Spar
Long Island	41	9.50	17.63	12.50	✓	✓		
Frying Pan Shoals	24	10.80	18.33	13.30	✓	✓		
WIS 63067	50	9.20	17.04	13.60	✓	✓	✓	
SE Nantucket	66	12.50	23.37	11.10	✓	✓	✓	
WIS 63235	130	8.04	15.00	13.21			✓	✓
Cape Cod	218	10.82	20.10	9.80			✓	✓
Port Orford	420	13.57	25.20	10.76			✓	✓
Point Conception	632	9.93	18.50	13.60			✓	✓
WIS 83078	849	8.83	16.40	15.28			✓	✓

Note: Information from NREL analysis

6.3.1.1 Fixed-Bottom Systems

Because the focus was on substructures, the study had initially assumed turbine towers that could be used for both floating and fixed-bottom configurations. The towers were designed for given hub heights and assuming a soft-stiff approach. The soft-stiff approach designs the first system eigenfrequency to be placed between the rotor (1P) and the blade-passing (3P) frequencies. For fixed-bottom substructures, the analysis made use of two tools available within NREL’s Wind-Plant Integrated System Design & Engineering Model (WISDEM™) software suite. WISDEM integrates a variety of models for the entire wind energy system, including turbine and plant equipment, O&M, energy production, and cost modeling (Dykes et al. 2011). The tool set allows for trade-off studies and guides the design of components as well as the overall system toward a configuration that minimizes the LCOE through multidisciplinary optimization. The submodules used in this study were TowerSE for monopile optimization and JacketSE (Damiani 2016) for jacket optimization. These sizing tools are described in more detail in Appendix C. The models were run to attain minimum-mass configurations of monopile-tower and jacket-tower support structures for various wind turbine ratings, hub heights, and metocean conditions. CapEx costs associated with the devised structures were then calculated based on unit costs; these are given in Table 8.

Table 8. Fixed Component Cost

Component	Cost/t (USD)
Pile	\$2,250
Monopile Transition Piece	\$3,230
Jacket Main Lattice Structure	\$4,680
Jacket Transition Piece	\$4,599

The output from TowerSE and JacketSE were compiled into mass schedules and separated into piles, transition piece, and main structure (shown in Figure 18 through Figure 23 for monopile and jacket-based systems, respectively). For 3-MW and 6-MW systems, some data are available from actual installations and other consultancy studies; these are also shown in the plots.

The monopile systems matched industry data relatively well at the shallowest water sites (depths from 10 m–25 m), but data revealed a large difference with increasing water depths. Part of this difference arises from the discrepancy in transition piece mass estimates. The models returned much lighter transition pieces, which is likely because of the absence of fatigue damage assessment in this simplified analysis.

For the jacket-based systems, the comparison to industry data showed good agreement. To arrive at this level of agreement, however, the design variable bounds had to be changed to account for stepwise schedules available in the market for structural tubing dimensions. Additionally, the footprint maximum dimensions had to be adjusted to reflect industry data, and the tower dimensions were allowed to be changed by the optimizer rather than being fixed as in the case of the floating substructures.

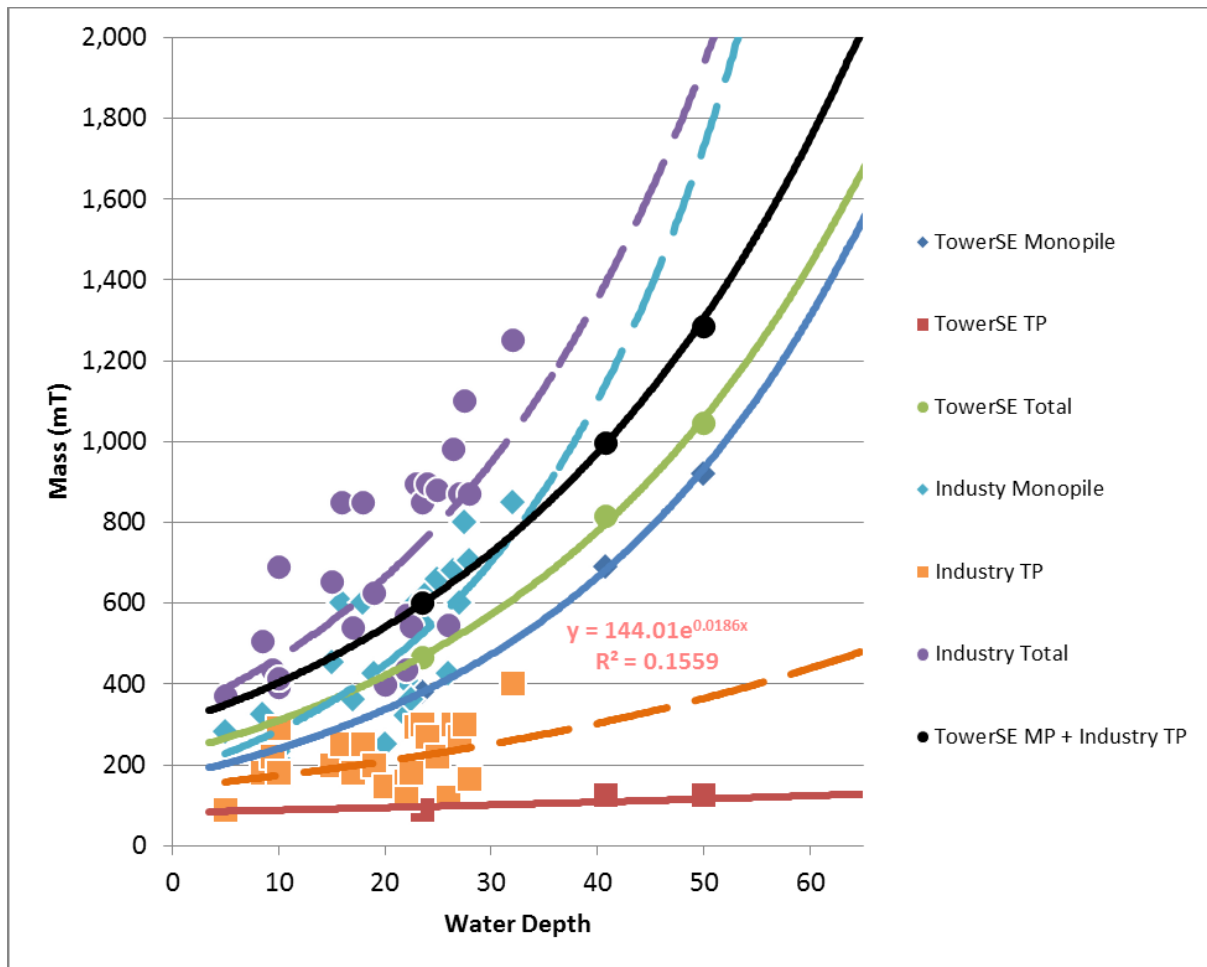


Figure 18. Mass results in metric tons for 3-MW monopile-based systems and comparison to industry data

Note: The lines represent best-fit curves of the data points.

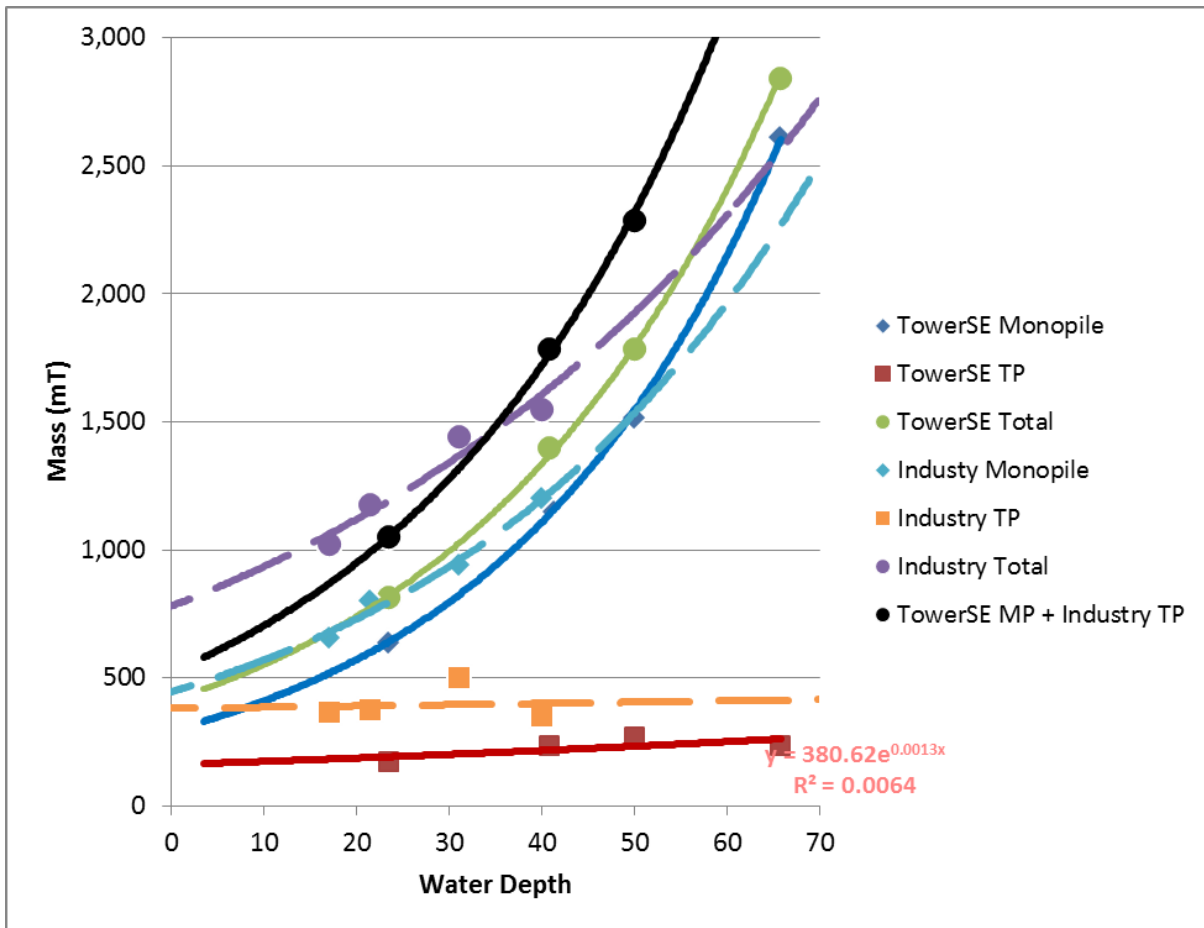


Figure 19. Mass results in metric tons for 6-MW monopile-based systems and comparison to industry data

Note: The lines represent best-fit curves of the data points.

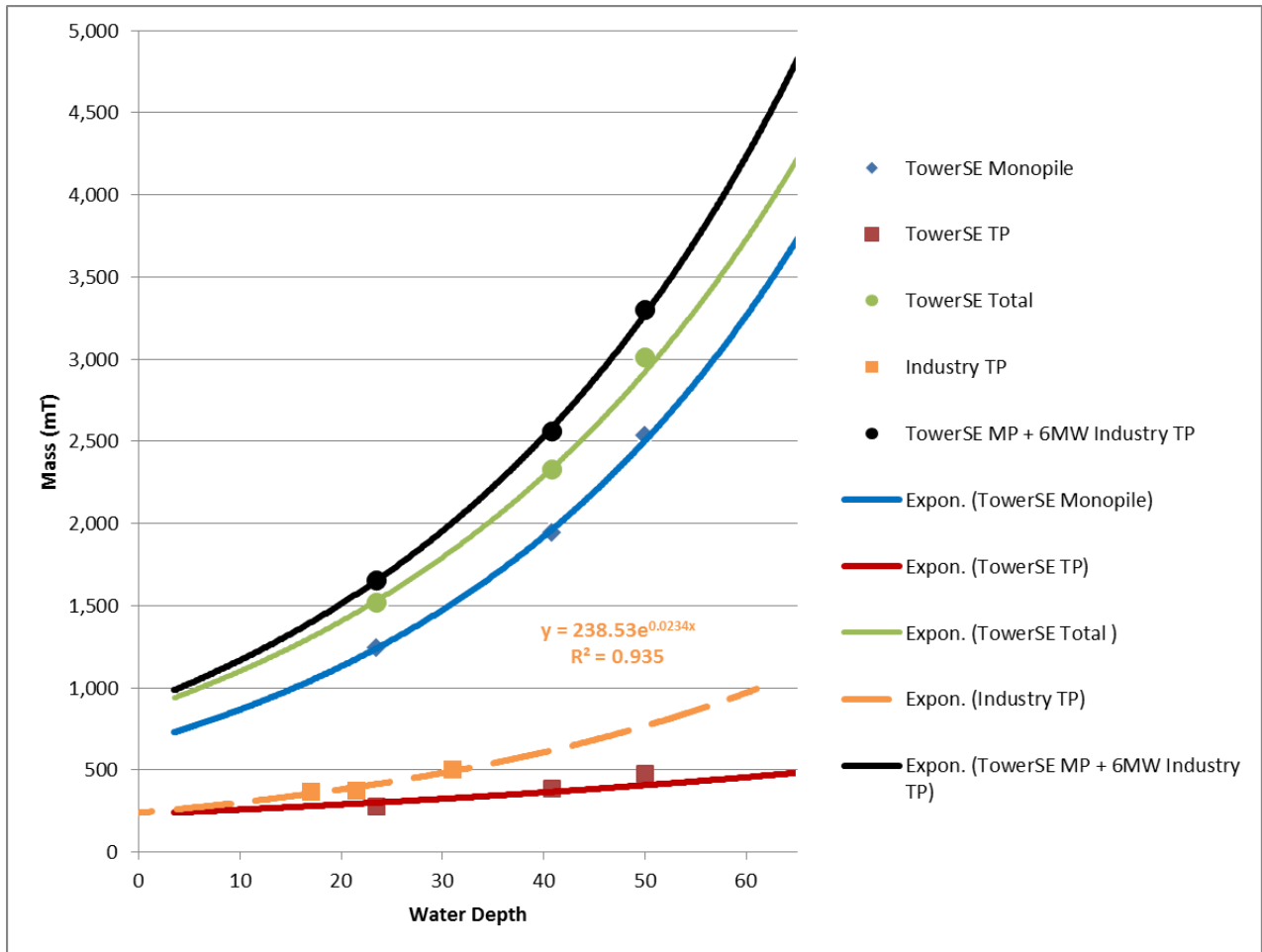


Figure 20. Mass results in metric tons for 10-MW monopile-based systems

Note: The lines represent best-fit curves of the data points.

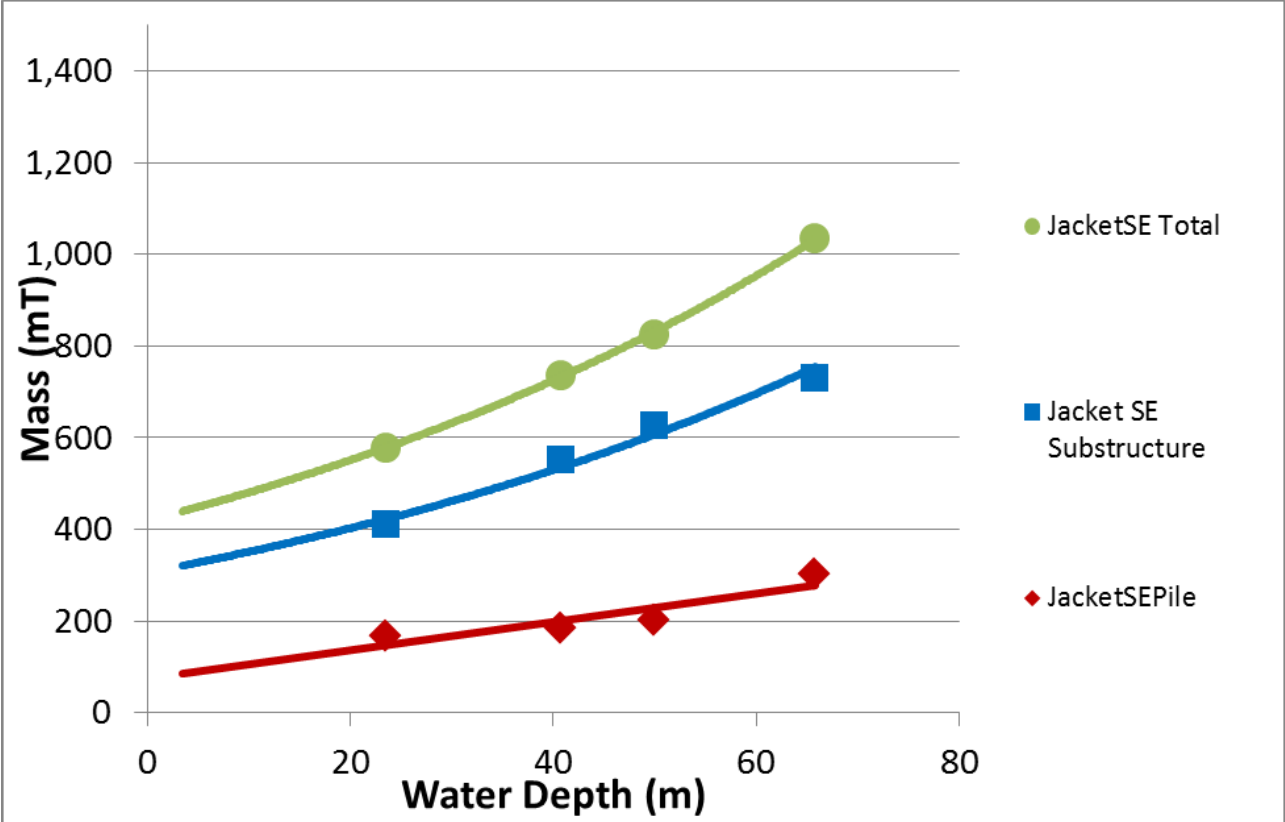


Figure 21. Mass results for the 3-MW jacket-based systems

Note: The lines represent best-fit curves of the data points.

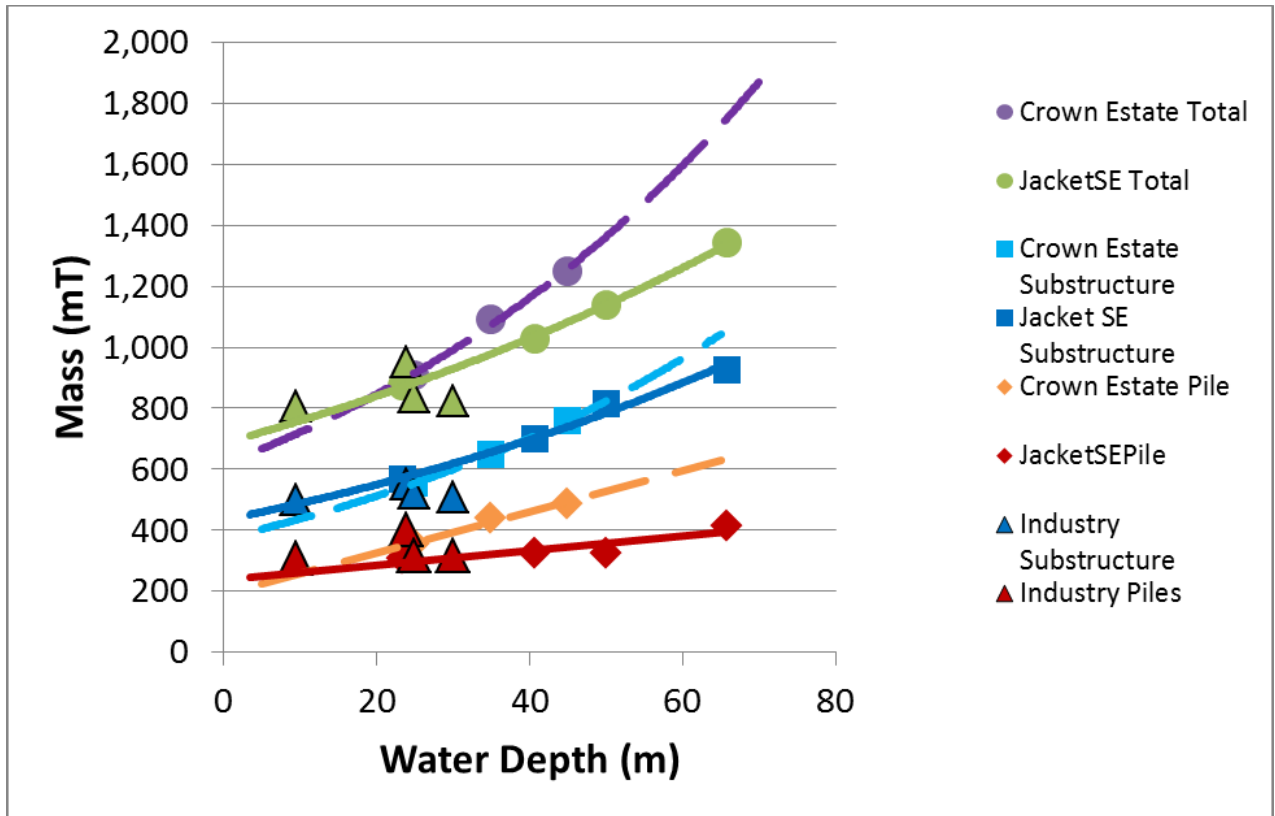


Figure 22. Mass results for 6-MW jacket-based turbine systems and comparison to industry data

Note: The lines represent best-fit curves of the data points.

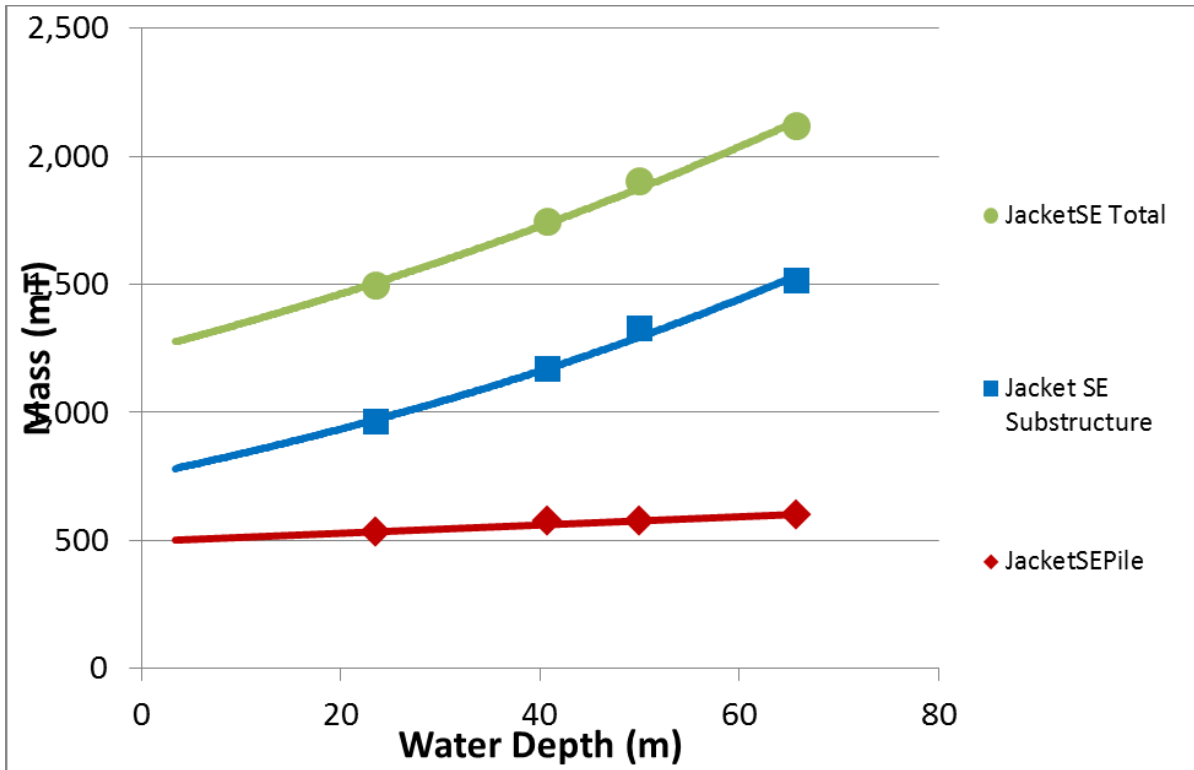


Figure 23. Mass results for the 10-MW jacket-based systems

Note: The lines represent best-fit curves of the data points.

6.3.1.2 Floating System

The assessment seeks the minimal overall mass for all substructure components, which are directly related to cost. It uses NREL’s Floater Sizing Tool to seek the minimal overall cost for all substructure components (e.g., the primary hull steel, outfitting steel, ballast, mooring lines, and anchors) given a set of constraints, which Appendix B describes in detail. The parameter study considers water depths ranging from 40 m–1,000 m for semisubmersibles and 80 m–1,000 m for spar buoys. The assessment also considers seabed soil conditions by developing cost estimates for the procurement of both drag embedment anchors and suction pile anchors.

To understand the cost of the substructure (see Table 9), the substructure needs to be broken down to components grouped by fabrication complexity (i.e., higher fabrication cost for more complex components). The spar mass is broken down to stiffened column, tapered column, and outfitting, whereas the semisubmersible is made up of stiffened columns, truss members (including pontoons), heave plates, and outfitting.

Table 9. Floating Component Costs

Component	Cost/t (U.S.\$)
Stiffened Column	\$3,120
Tapered Column	\$4,220
Truss Members	\$6,250
Heave Plate	\$5,250
Outfitting	\$7,250
Fixed Ballast	\$150

The substructure includes the mooring system, which consists of chain and anchors. The mooring chains are costed (USD) by providing the length (L) in meters and chain minimum breaking load (MBL) in kN:

$$\text{Chain Cost} = (0.0591 \times \text{MBL} - 87.6) \times L \quad (4)$$

Although a chain solution for the mooring system is advantageous in shallower water sites, the costs increase linearly with depth as a result of the lengths of chain required. Steel strand and fiber ropes are alternative options that could provide cost savings at deeper water sites; however, identifying the economic break points between the chain and these alternative configurations would require detailed application and qualification studies. These types of studies are beyond the scope of this assessment (chain was the only mooring system configuration considered).

Even though many anchor types are possible, the mooring line configuration in the Floater Sizing Tool has two built-in options: suction pile anchors and drag embedment anchors. This study applies only drag embedment anchors. The anchors are costed (in USD) by providing the minimum breaking load in kN:

$$\text{DEA Cost} = 10.198 \times \text{MBL} \quad (5)$$

NREL's Floater Sizing Tool calculates the cost of these anchors as a function of mooring line tension at the anchors, and NREL has not yet implemented codes to size anchors in a way that considers the anchor-holding capacity in the context of relevant soil parameters. These model limitations prevented NREL from conducting a quantitative parameter study to define anchor suitability in each soil type from an economic perspective. Instead, this analysis takes a simplified approach toward considering geotechnical conditions. The soil type is classified per the Folk classification, and NREL conducted a qualitative assessment to assign the appropriate anchor type to each soil type.

The substructure total mass for a specific turbine size is somewhat independent of water depth and more dependent on the environmental conditions at a given site. The main impact of depth is on the mooring system, which provides the restoring forces needed for station-keeping and transfer loads to the anchors on the seabed. As the lines get longer for deeper water, the chains

get heavier, which may impact the substructure. To accommodate the heavier chain, the system buoyancy needs to be offset by either providing longer stiffened columns or reducing ballast.

For the spar, the ballast reduction was not possible from the 130-m design to accommodate the heavier mooring chain for deeper waters, and the column had to be lengthened because its diameter remained fixed to provide the additional buoyancy. As a result, this requires additional stiffeners to compensate for the increased hydrostatic pressure from the deeper draft. Hence, the mass of the spar increases for deeper waters. The cost impact going to deeper waters for the spar is both from the hull and mooring system. The semisubmersible, on the other hand, was able to remain at the same draft and column diameter by reducing only the ballast to provide more buoyancy to accommodate the heavier chain.

The resulting masses are confidential; however, these values were used in the LCOE calculation presented in the cost section.

6.3.2 Electrical Infrastructure Parameter Study

The electrical infrastructure parameter study investigates the cost relationship between electric system elements and spatial parameters. The analysis assumes that the system is laid out according to the generic plant layout of 100 6-MW turbines (see Section 3). For this analysis, NREL divided the electrical infrastructure into the following three subsections: the array system, export system, and grid connection, as shown in Figure 24.

- The **array system** collects power from the transformers of individual wind turbines and delivers it to the offshore substation transformer(s) via a grid of 33-kV submarine cables.
- The **export system** steps power up to the export voltage and transmits it through subsea cables to the land-based substation.²⁹ It includes:
 - A high-voltage alternating current (HVAC) offshore substation and, if applicable, an HVDC converter terminal platform
 - High-voltage submarine cables (including cable landing)
 - A land-based substation and, if applicable, HVDC converter terminal platform.
- **Grid connection** covers transmission lines and substation upgrades or the construction required to link the project from the land-based substation to the point of interconnection.

NREL estimates grid connection through an algorithm that assigns each potential offshore wind power project to a “grid feature” based on the estimated capacity available at each feature. Grid features can be an existing substation, existing transmission line, load center (more than 10,000 people), or potential central export point.³⁰ Once a grid feature has been assigned, the algorithm estimates costs through the application of cost multipliers.

²⁹ Note that some technology that would be required to export power from floating offshore wind projects has not yet been qualified. Notable examples include 220-kV HVAC and 320-kV HVDC power cables. This analysis assumes that this technology will emerge to meet demand as floating offshore wind technology matures.

³⁰ The grid feature GIS layer is described in Appendix A.

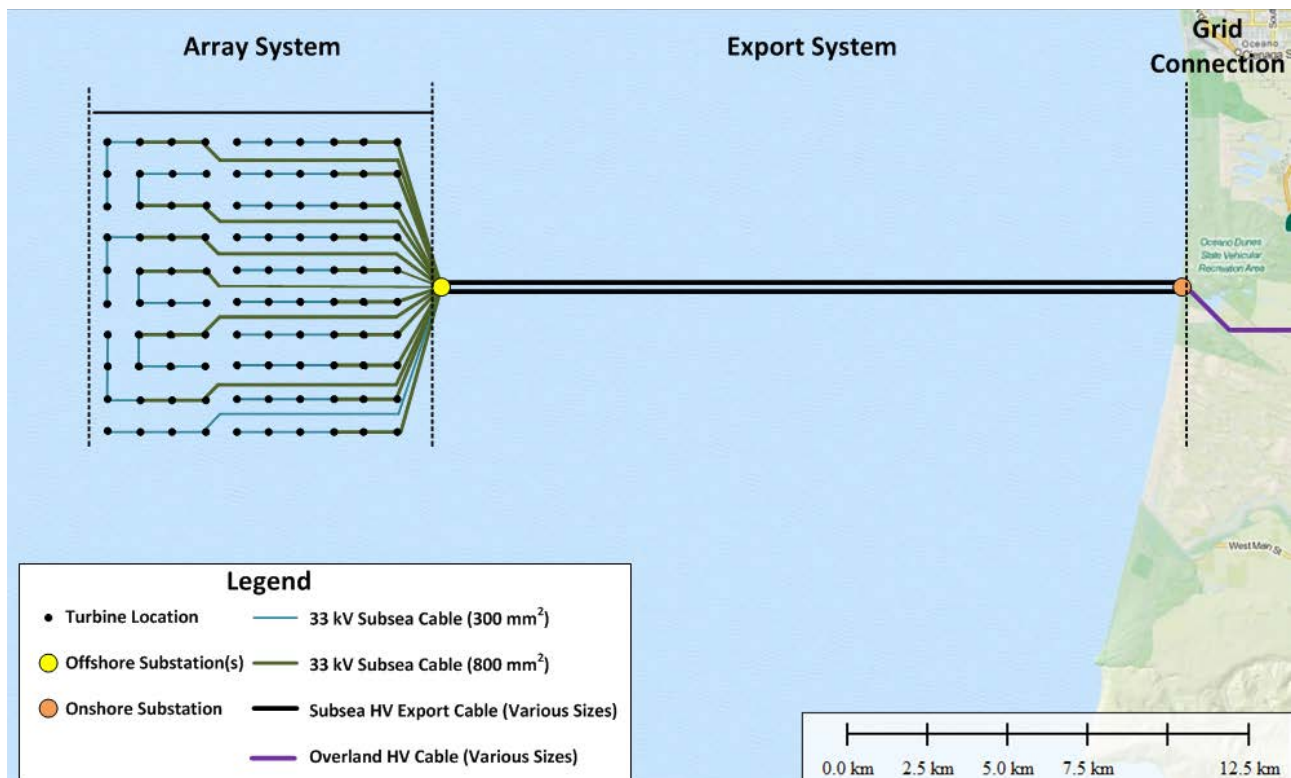


Figure 24. Map showing the boundaries among electrical infrastructure categories

Structural modeling of the cables to evaluate how possible configurations would perform with respect to strength and fatigue was not in the scope of this assessment. Instead, analysts used a simple, geometric method to reasonably approximate the relationship between the array cable system length and water depth. Once cable lengths are known, analysts apply factors for procurement and installation costs to the various quantities of cable. Figure 25 and Figure 26 show the total cost of procuring and installing the array system among the various water depths considered in this study.

Offshore wind power projects in the United States could be installed at sites that span a considerable range of distances from the nearest viable point where the power cable could be brought to shore. Variability in the distance between the project and substation will have implications for export system design given trade-offs among the costs of infrastructure (e.g., substation and converter stations), power cables, and restrictions on real power transfer. The cost of HVAC and HVDC transmission options depends on many factors, including transmission distance, plant capacity, and water depths. HVDC transmission is considered a more economic choice for longer transmission distances (>100 km) because of the lack of active power transfer capacity limitations (there is no need for reactive compensation at both the sending and receiving ends), lower cable costs, and lower active losses.

Given the variety of export systems that are possible and the scope of potential offshore wind power project sites considered in this report, it is essential to look at multiple designs to realistically characterize how system costs and losses will change with respect to distance from the point of grid connection. Four configurations are considered:

- 33-kV medium-voltage alternating current (power fed directly to shore with no substation)
- 132-kV HVAC
- 220-kV HVAC
- ± 320 -kV HVDC (bipolar HVDC topology assumed).

The export system parametric study characterizes how the total system costs (encompassing CapEx and lost revenue)³¹ changes with respect to the distance between the project and the point of interconnection. The parametric study considered costs and lost revenue (valued at \$150/MWh) for each of the four export systems for distances ranging from 0 km–200 km.

Results for each export system configuration are compared to identify economic break points between the export system technologies. Figure 25 and Figure 26 summarize the results of the parameter study by comparing CapEx and total system costs (CapEx + revenue losses) for each of the export systems considered in this analysis and fixed-bottom and floating technology, respectively.

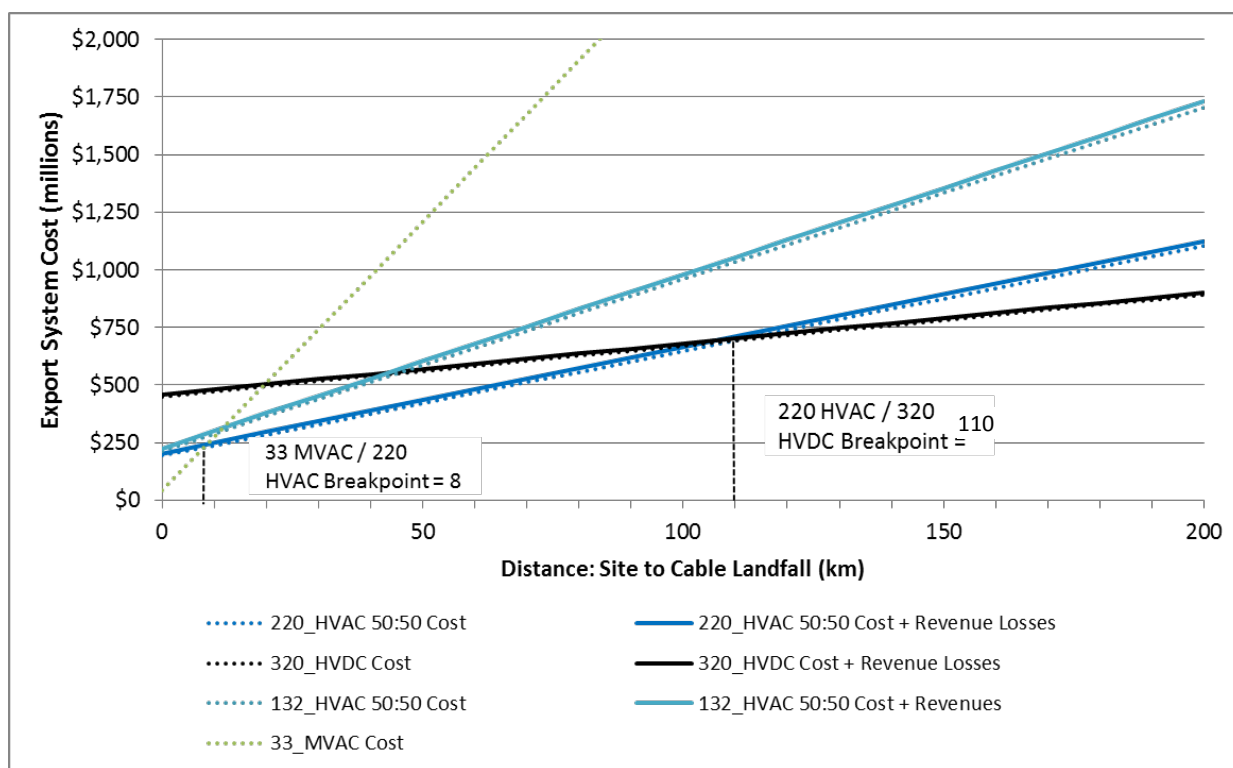


Figure 25. Summary of export system parameter study results for fixed-bottom technology

³¹ Each export system has different reliability and redundancy characteristics that will have implications for both OpEx and energy production (availability). These impacts are not considered in this analysis because of a lack of reliable information.

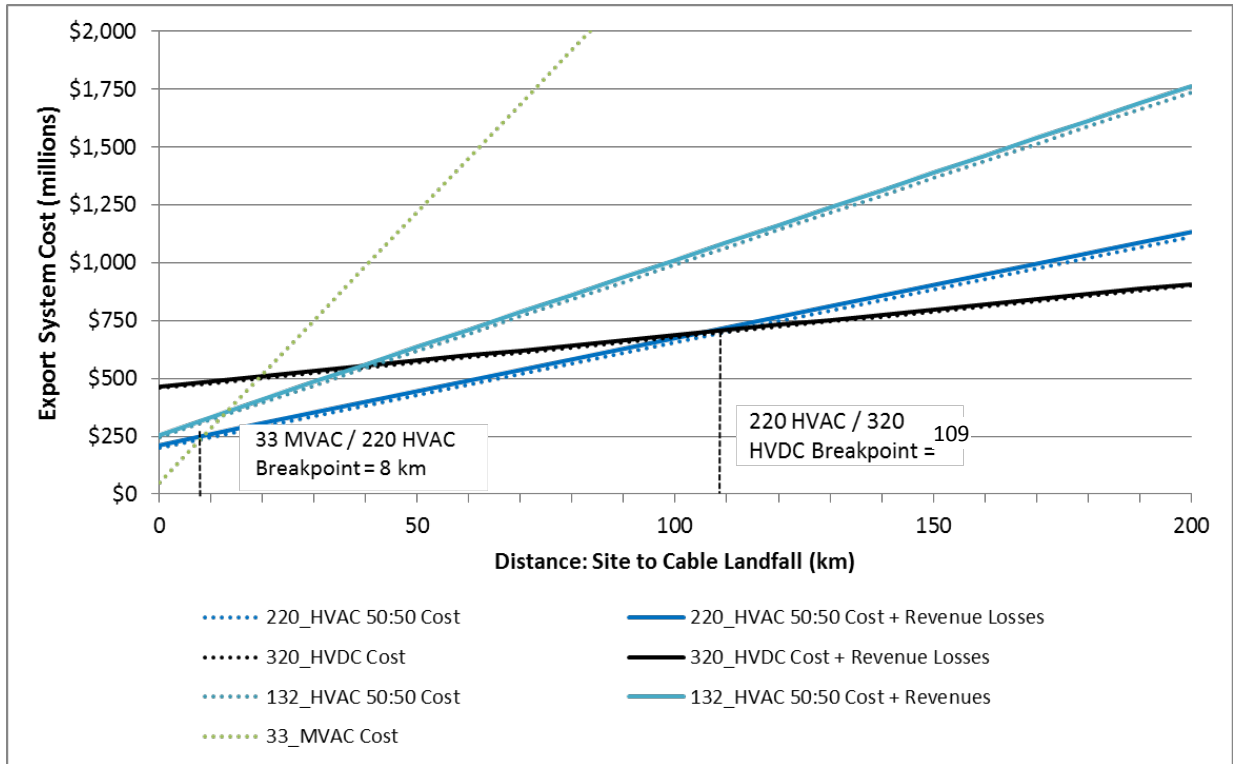


Figure 26. Summary of export system parameter study results for floating technology

Looking at total costs, the 33-kV system is the lowest cost option from 0 km–9 km. The 220-kV system becomes the lowest cost option from 9 km–115 km. HVDC systems appear suitable from 115 km onward. The 132-kV HVAC system is not the lowest-cost option at any distance because of the requirement for two substations. Although it is beyond the scope of this study, it is recognized that 132-kV systems may be the best option for some sites given local grid conditions at the point of interconnection. Other advanced collector system designs and higher voltages (e.g., 66 kV) have a promising potential for future cost reductions of offshore collector systems.

More details can be found in Appendix C.

6.3.3 Installation Parameter Study

The installation parameter study investigated how installation costs scale with substructure type, turbine size, and spatial parameters—specifically distance from project site to staging port, turbine nameplate rating or size, and metocean conditions.³² The installation parameter study was performed using NREL’s BOS cost model, which is an internal model, including installation costs.

The parameter study was based on three distinct installation strategies that are specific to substructure type.³³ For the fixed substructures, monopile and jacket, the substructures are

³² The costs to install the electrical infrastructure (e.g., array cables, export cables, and substation/converter platforms) were considered separately in the electrical infrastructure parameter studies (see Section 6.3.2).

³³ Installation strategies assume zero weather downtime. Weather downtime is assessed via a contingency factor; see Appendix C.

loaded onto an installation vessel at the staging port for transportation to the project site where the substructures will be installed. The turbine installation is performed in a fashion similar to that of the turbine components being loaded onto the installation vessel at the staging port, transported to the project site, and then assembled and installed onto the preinstalled substructure at the site.³⁴

Two strategies were analyzed for the spar; the first is based on a vertical-tow installation method. For this strategy, the installation of the turbine takes place at a protected inshore assembly area where turbine components are transported via barge and tug and assembled onto the upended spar substructures. Once assembled, the turbine is towed (in a vertical configuration) by a lead anchor-handling tug supply vessel and support vessels to the project site where the assembly is connected to its preinstalled mooring and anchor system.

The other spar installation strategy assumes that a purpose-built vessel has been developed for spar installation that can transport the spar and turbine assembly in a horizontal configuration and upend the assembly for installation at the project site. Spar substructures are towed horizontally to the staging port where the turbine is installed. The turbine and spar assembly is then towed, still in horizontal configuration, to the project site where it is upended, ballasted, and attached to the preinstalled anchor and mooring system. The advantage of using this strategy is that no sheltered inshore assembly area is required to carry out the installation of the turbine onto the substructure, but a 5% cost adder was applied to the turbine to account for upgrades that would allow the turbine to be assembled and transported in a horizontal configuration.

The semisubmersible platform installation takes a relatively simple approach. The substructure is either floated and towed to the staging port from the fabricator or assembled at a co-located fabrication facility. The semisubmersible hull is positioned at the quayside where the turbine is installed and precommissioned. Assembly takes place at the port facility, and there is no need to mobilize heavy lifting equipment to an inshore assembly area or to the project site. Once assembled, the turbine is then towed by a lead anchor-handling tug supply vessel and support vessels to the project site where it is attached to the preinstalled mooring and anchor system.

Each of these installation strategies yields different costs, and analysts used NREL's offshore BOS model to develop curves that relate the installation costs for each substructure and corresponding installation strategy to key spatial and technical parameters. The key parameters covered in this study include logistical distances, which are relevant for the transportation of components, and they include the distances from the staging port to the project site, from the staging port to the inshore assembly area, and from the inshore assembly area to the project site; the water depth, which is a driver of substructure size and mooring line length for fixed and floating substructures, respectively, as well as installation vessel selection; and, last, the turbine size, which also drives the substructure size and mooring line requirements. Distance bounds were set from 0 km–500 km from the relevant node (either staging port or assembly area). Water depths ranged from 0 m–100 m and from 100 m–1,000 m for fixed and floating substructures, respectively. The turbines analyzed in this study were 3 MW, 6 MW, and 10 MW in size. Parameterizations were performed for each of the three sizes considering the logistical distances

³⁴ The number of turbines or substructures loaded onto the installation vessel varies by turbine and substructure physical size and the operational limits of the selected vessel.

and the water depth parameters. Table 10 shows a breakout of the parameter ranges and increments considered in this study.

Table 10. Key Parameter Ranges

Variable	Fixed Substructure	Floating Substructure
Water Depth	10 m–100 m, 10-m increments	66 m–1,000 m, varying increments
Distance from Port to Site	50 km–500 km, 50-km increments	50 km–500 km, 50-km increments
Distance from Port to Assembly Area	—	50 km–500 km, 50-km increments (spar only)
Distance from Assembly Area to Site	—	50 km–500 km, 50-km increments (spar only)

Installation vessel selection is a key driver of installation costs and depends largely on operational limits of each vessel. Vessel operating limits—which include maximum lifting or crane capacity and operational water depth—depend on the turbine and substructure size as well as the water depth. The smallest, least-expensive vessel that had specifications within the selection criteria was selected; and as the key parameters were varied, larger-class vessels were selected once operational limits were exceeded. For water depths greater than 70 m, which is beyond the operational depth of any available jack-up vessel to date, a 10% premium was added to the vessel day rate to account for upgrades that would be required to operate it in deeper waters.³⁵ A 30% adder was applied to vessel day rates for the 10-MW case to anticipate future vessels and technologies.³⁶ Table 11 shows a detailed list of the vessels and their specifications used for installation, and a detailed breakdown of the vessel-selection strategy is provided in Appendix C.2.

³⁵ As of November 2015, the largest available jack-up vessel, the Seajacks Scylla delivered in November 2015, has an operational water depth limit of 65 m.

³⁶ Vessel day-rate cost adders are qualitative approximations based on information provided by industry.

Table 11. Installation Vessels. Photos provided by DONG Energy (Sea Power), Maritime Journal (MPI Resolution), MPI Offshore LTD (MPI Adventure), Swire Blue Ocean (Pacific Orca), and Heerema Marine Contractors (Thialf)

Vessel (From Offshore BOS Model)	Description	Max Payload (tonne)	Max Lift Capacity (tonne)	Max Operational Water Depth (m)	Comparable Industry Vessel	
Mid_Mid_Sized_Jack_Up_Vessel	Low capacity, low jack up height	1910	317	33.8	Sea Power	
Mid_Large_Sized_Jack_Up_Vessel	Medium capacity, low to medium jack up height	4400	717	45	MPI Resolution	
High_Mid_Sized_Jack_Up_Vessel	Medium to high capacity, medium jack up height	5750	1130	48.3	MPI Adventure	
High_Large_Sized_Jack_Up_Vessel	High capacity, high jack up height	8000	1375	57.8	Pacific Orca	
Semi_Submersible_Crane_Vessel	High cargo capacity, high lift capacity	10,000	7,100/14,200 single/tandem	∞	Thialf	

To estimate the sensitivity of installation costs to distance, NREL developed a data layer that identifies locations (World Port Index) that may be suitable when using filters that include channel depth, degree of shelter, and access to an offshore resource area. The indexed ports consist of 85 construction ports that are suitable for fixed-substructure staging and installation operations and 59 other construction ports with no overhead clearance limitations that are suitable for floating systems where turbines can be mated to the substructure in the port and towed out. Also included are 130 operations ports that are suitable to support the maintenance activities for offshore wind power projects. Operations ports have relaxed channel depth and infrastructure requirements relative to construction ports. Figure 27 shows the locations of the indexed ports and sheltered inshore assembly areas.

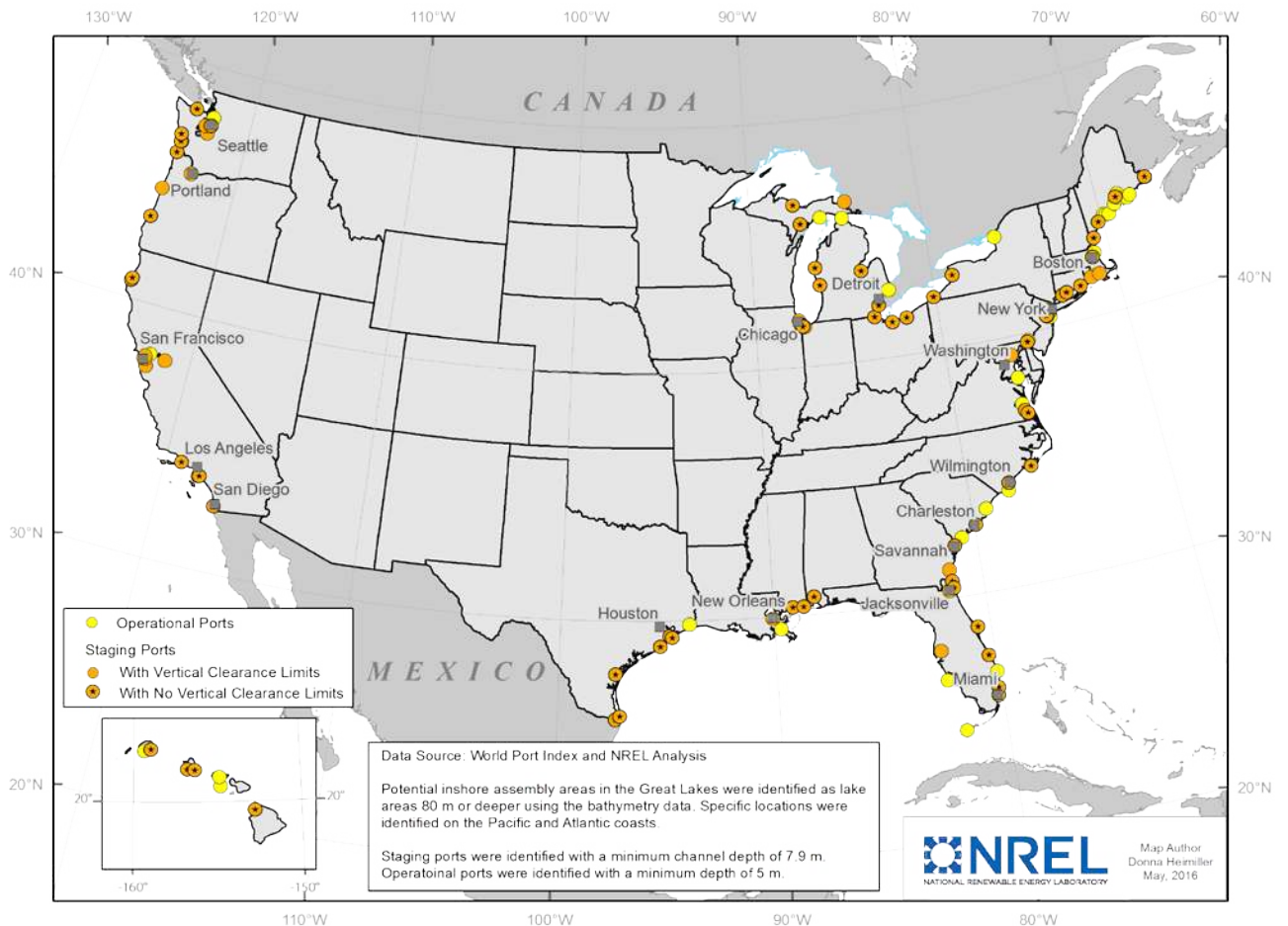


Figure 27. Construction and operations port and inshore assembly area locations

Sensitivities were performed using the offshore BOS cost model by varying each of the key parameters one at a time for each of the scenarios, which include three turbine sizes with four substructure types for a total of 12 unique scenarios. Cost outputs were then used to develop curve-fit relationships that scale with the key parameter inputs. Cost-estimating relationships were divided into three different categories: substructure installation cost; turbine installation cost; and port, staging, and transportation costs. Detailed information on the curve-fitting process and results are provided in Appendix C.2. The resulting curve fits were then used to build more complex algorithms implemented in the spatial-economic framework that apply various adjustment factors and can recognize inputs such as substructure type or turbine size and calculate costs accordingly. One key adjustment that was applied is a Jones Act-compliance adder. The Jones Act stipulates that only U.S.-flagged vessels can make trips between two U.S. ports. As a result, a cost multiplier is applied that accounts for the additional cost foreseen from using only U.S.-flagged vessels that have substantially lower installation capabilities compared to the purpose-built fleet of European turbine installation vessels. Therefore, two factors were developed that include a 23% adder for 2015 (COD) and 2022 (COD) and a 5% adder for 2027 (COD) in anticipation of a greater market share of U.S.-flagged turbine installation vessels.

These Jones Act values were determined by analyzing the differences in cost between using a European, purpose-built turbine installation vessel for installation and utilizing only U.S.-flagged vessels capable of performing the same installation. The cost differences were used to build an average cost percent adder that could be applied to installations assuming the use of a European turbine installation vessel to estimate the cost of a Jones-Act-compliant installation using only U.S.-flagged vessels (for more details, see Appendix C.3). The Jones Act cost adder is applied to assembly (CapEx), installation (CapEx), and maintenance (OpEx) cost items.

Another critical adjustment made was applying a factor to fixed substructure installation timing that scaled the time required to carry out installation activities with turbine size. The offshore BOS model does not take into account the increasing installation time required as turbine size increases; therefore, curves were developed for each scenario that show the relationship between installation time and turbine size.³⁷ For floating substructures, no adjustment was made because the relationship between turbine size and installation time is less clear and not considered as significant. More information about the factors applied in this parameter study can be found in Appendix C.3.

The end result of the installation parameter study was a series of equations that calculate the total installation cost of the offshore wind power plant but exclude electrical infrastructure installation costs. Three equations were developed for each of the 12 unique scenarios described in this study. For each scenario, we developed an equation that estimates turbine installation costs, one that estimates substructure installation costs, and one that estimates port and staging costs. These base equations accept site-specific input parameters such as water depth and logistical distances, and as part of the larger framework they will calculate installation costs based on the turbine size, substructure type, and overall size of the wind power plant. For a full list of the equations that were developed from this study and details regarding the development process, see Appendix C.2.

6.3.4 Operation and Maintenance Parameter Study

OpEx costs are expected to vary considerably among offshore wind power plant locations. From previous experience (Maples et al. 2013; Jacquemin 2011; Pieterman et al. 2011), the two largest locational drivers of O&M cost differences among offshore wind power projects are the distance between the project and maintenance facilities (e.g., O&M port and/or inshore assembly area) and the prevailing metocean climate at the project site.³⁸ An O&M port serves as the base from which the operator coordinates maintenance and repair operations; it does not require the same infrastructure as a staging port and could be built as part of a project. Figure 10 in Section 4 shows relevant logistical points that could support operations for offshore projects depending on the substructure technology. The O&M parameter study considers these locational drivers for both fixed-bottom (e.g., monopile or jacket) and floating (e.g., spar or semisubmersible) offshore wind technologies.

³⁷ Installation duration adjustments were added to capture directionality; however, these adjustments need to be substantiated with data collection or engineering analysis.

³⁸ O&M costs for floating projects will likely have some sensitivity to water depth because of different vessel and equipment requirements; however, enough information is not yet available to accurately quantify this relationship.

The Energy Research Centre of the Netherlands (ECN) developed the ECN O&M Tool, which is used to investigate the sensitivity of OpEx to these spatial parameters by holding constant assumptions about technology and project characteristics. The O&M analysis assumes different strategies for fixed-bottom and floating technologies. The fixed-bottom substructures assume that major turbine component replacements are conducted at the project site or in situ by mobilizing a jack-up crane vessel. The strategy for floating substructures assumes that a major turbine component is replaced by towing the turbine in a vertical configuration to an inshore assembly area or O&M port using an anchor-handling tug supply vessel with two assist tugs. As a result, components can be replaced in a sheltered environment and then towed back to their position within the project and reconnected to their respective moorings and power cables.

In practice, project sponsors optimize the spread of equipment that is used for a given project depending on its unique conditions—predominantly distance from O&M facilities and the metocean climate.³⁹ An optimized O&M strategy is one that simultaneously minimizes direct OpEx while maximizing the revenue that the project can generate through power sales (maximizing availability).

It is observed that the ECN O&M Tool is conservative in estimating the range of availability results when compared to other O&M models. It is nearly impossible to achieve availability results higher than 95% using the ECN O&M Tool, but operating projects are reporting that availability can reach 97%–98% in the best case; therefore, we apply a 2% adjustment factor increase in availability to the maximized availability results to compensate for this. Continued verification of O&M models and the collection of additional data on availability levels for modern offshore wind power projects is expected for further investigation on the lower-than-expected availability results.

This assessment approximates this optimization exercise by considering scenarios that vary the spread of vessels and equipment used to perform O&M activities within the broader in situ approach to maintenance for fixed-bottom substructures and the tow-to-shore approach for floating. The following four strategies are considered:

- **Close to shore.** Port-based with a “basic” crew transfer vessel (CTV), maximum operating wave limit = 1.5 m Hs, and transport speed = 20 kn
- **Close-to-shore plus (+).** Port-based with “advanced” CTV, maximum operating wave limit = 2.3 m Hs, and transport speed = 20 kn
- **Medium distance.** Port-based with surface effect ship, maximum operating wave limit = 2.5 m Hs, and transport speed = 35 kn
- **Far shore.** Mothership-based with a heave-compensated gangway and maximum operating wave limit = 2.5 m Hs.

Further details on each of the scenarios can be found in Appendix C. Note that several of these strategies rely on vessel concepts that are still in the proof-of-concept phase, in which the vessel is either undergoing sea trials or under construction. Although NREL used the best-available

³⁹ Other considerations include project size, technology type, local infrastructure availability, and so on; however, these considerations are assumed constant in this assessment.

information, uncertainties about the costs and capabilities of these new vessel types are still present.

The ECN O&M Tool requires inputs for wind and wave limitations on equipment utilized for O&M activities as well as time-series metocean data specifying significant wave height and wind speed. Because time-series data sets are not available for every location in the U.S. resource area, NREL developed three sites for use in the O&M analysis that are broadly representative of the different U.S. metocean conditions: mild, moderate, and severe. Analysts gathered and processed time-series wind and wave data from each of these three wave information system (WIS) stations to create an input deck for the ECN O&M Tool (i.e., 10 years of correlated wind and wave data at hourly intervals). Figure 28 shows how each location within the offshore resource area is assigned to one of the three representative sites based on its average annual wind speed and significant wave height characteristics. Details about the three representative sites are included in Appendix C.2.4.

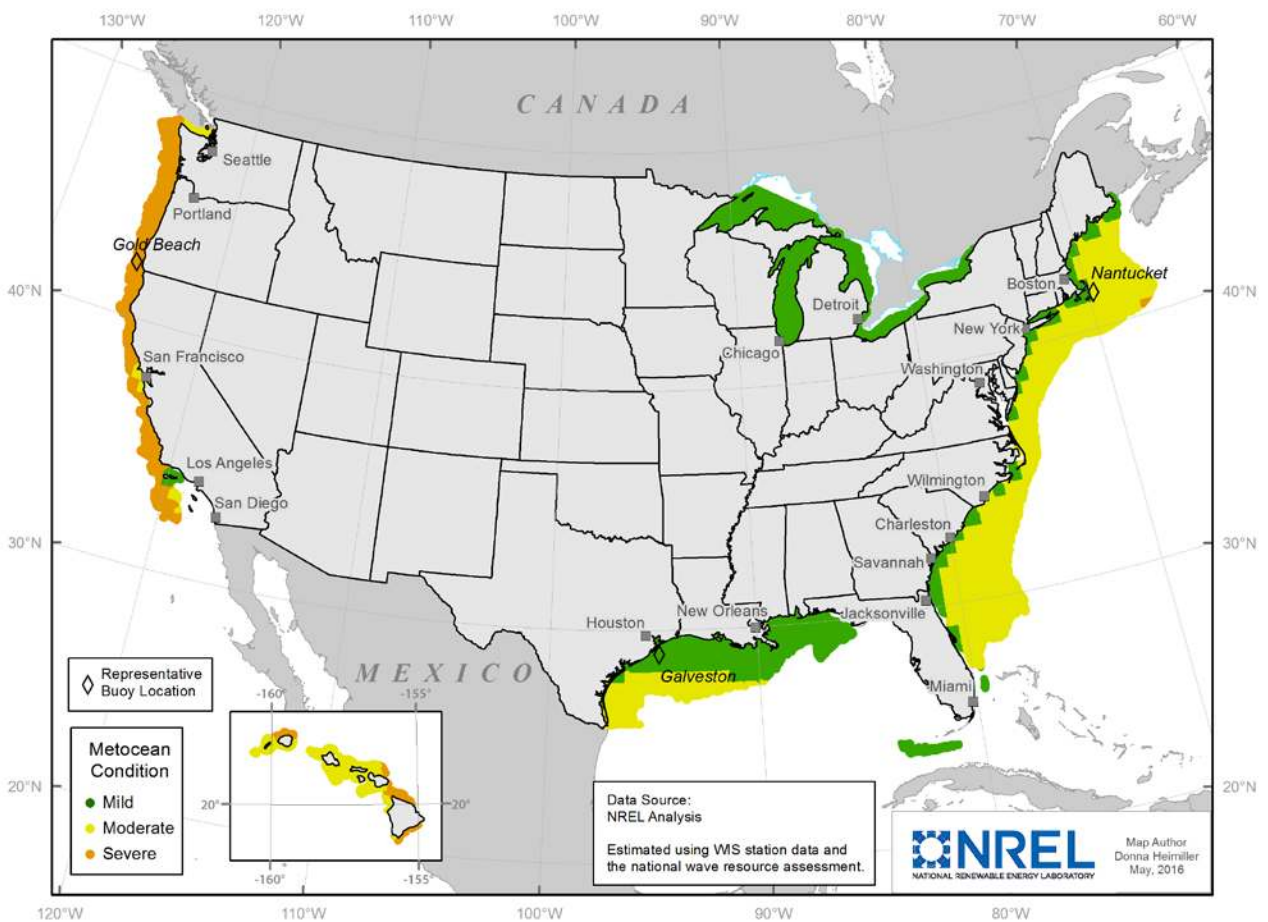


Figure 28. Representative WIS stations for O&M analysis

The parameter study investigates how OpEx and availability change with respect to metocean conditions, distance to shore, and O&M strategy for fixed-bottom and floating technologies for

each of the representative sites. Table 12 illustrates the matrix of O&M scenarios run for the analysis.⁴⁰ Analysts selected the three sites (i.e., mild, moderate, and severe) to represent the range of metocean conditions among the U.S. offshore wind resource areas. The ECN O&M Tool was set up and run using the 10 years of correlated wind and wave data for each of the representative sites. After completing the runs, analysts then interpolated the results across the OCS by using average significant wave height as an indicator of the severity of site-specific metocean conditions because wave height is the dominating parameter in determining vessel requirements and accessibility.

⁴⁰ Note that the variability associated with the distance between the project and assembly area is considered separately from this matrix to keep the number of O&M model runs at a reasonable level. Also, the operation has a linear relationship with depth, is insensitive to weather conditions, and is unaffected by O&M strategy (see Appendix A).

Table 12. Matrix of OpEx Modeling Parameters

Distance to O&M Port (km)	Metocean Conditions								
	"Mild" Site			"Moderate" Site			"Severe" Site		
	Mean Hs = 0.88 m Mean Wind Speed = 6.12 m/s ^a			Mean Hs = 1.39 m Mean Wind Speed = 7.32 m/s ^a			Mean Hs = 2.50 m Mean Wind Speed = 6.61 m/s ^a		
10	CS ^a	MD ^b	FS ^c	CS+ ^d	MD	FS	CS+	MD	FS
30	CS	MD	FS	CS+	MD	FS	CS+	MD	FS
50	CS	MD	FS	CS+	MD	FS	CS+	MD	FS
70	CS	MD	FS	CS+	MD	FS	CS+	MD	FS
90	***	MD	FS	***	MD	FS	***	MD	FS
110	***	MD	FS	***	MD	FS	***	MD	FS
150	***	MD	FS	***	MD	FS	***	MD	FS
200	***	***	FS	***	***	FS	***	***	FS
300	***	***	FS	***	***	FS	***	***	FS
400	***	***	FS	***	***	FS	***	***	FS
500	***	***	FS	***	***	FS	***	***	FS

^a Mean wind speed at 10 m above mean sea level

^a Close to shore

^b Medium distance

^c Far shore

^d Advanced close to shore

*** Distance exceeds the 2-hour limit for transporting technicians between the O&M port and the project

The parameter study results in a matrix of outputs for OpEx, availability, and total O&M costs (OpEx + lost revenue).⁴¹ Analysts evaluated total O&M cost results to identify economic break points among O&M strategies for each of the three representative sites. The total O&M cost results for fixed-bottom and floating scenarios specific to the moderate site are presented in Section 6.3.5 and Section 6.3.6, respectively. The results for the mild and severe sites for fixed-bottom and floating substructures can be found in Appendix C.

6.3.5 Fixed-Bottom Technology

This analysis considers fixed-bottom technologies to include both monopile and jacket substructures because the differences in the substructure technologies do not significantly impact the O&M cost estimates. For this reason, we categorized monopile and jacket substructures as fixed-bottom substructures for the O&M parameter study. In general, the scenarios with a fixed-

⁴¹ Analysts calculated lost revenue as the opportunity cost of power that could have been generated if availability losses were equal to zero; this was valued at \$150/MWh.

bottom substructure technology assume that a jack-up crane vessel is mobilized to conduct major component replacements at the project site with all other inspections and repairs executed by technicians transported to the project site on a CTV with assistance from a supply vessel when necessary. The BOS maintenance is generally executed by technicians, and a cable-laying vessel is mobilized to repair export and array cables when necessary. The resulting total O&M costs (OpEx + lost revenue) specific to a fixed-bottom substructure for the moderate site are shown in Figure 29.

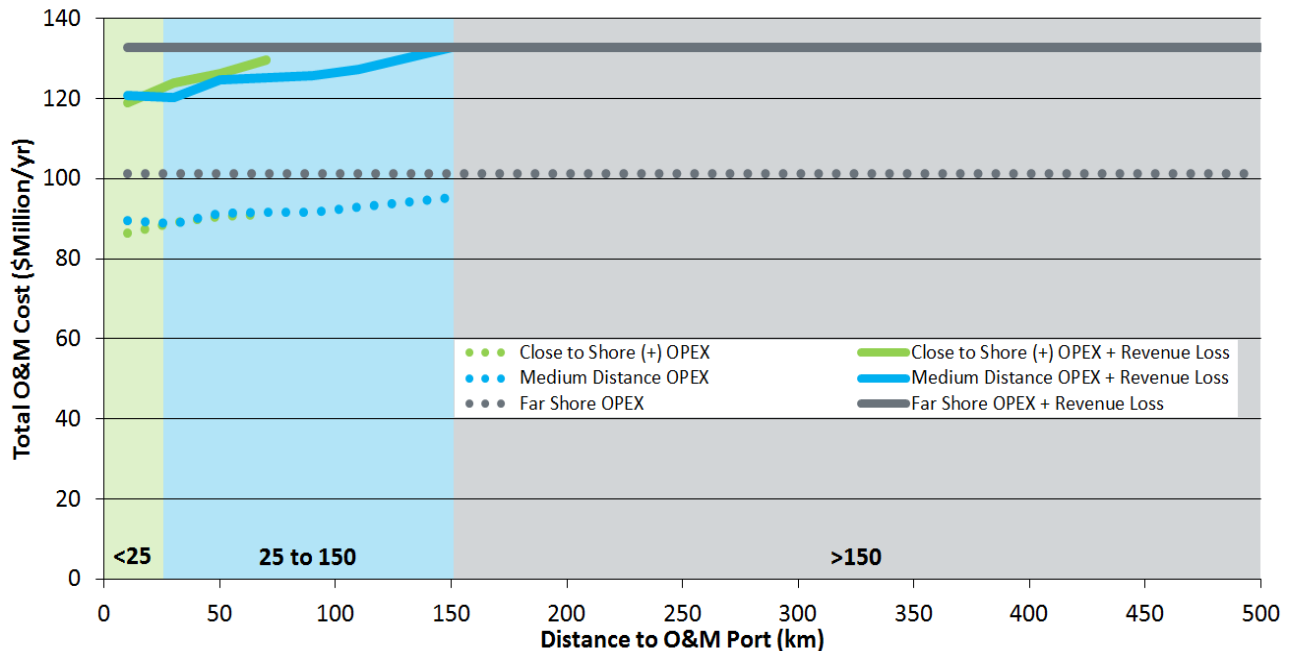


Figure 29. Moderate site total O&M costs for the fixed-bottom substructure

Figure 29 illustrates the economic break points among O&M strategies. The close-to-shore (+) strategy is the low-cost approach from 0 km–25 km. However, once the distance is greater than 25 km, revenue losses begin to increase sharply, and the optimal strategy becomes the medium-distance approach. The medium-distance approach remains the optimal strategy until reaching the imposed transportation limit of approximately 2 hours (one way). After this point (~150 km), the far-shore strategy is the only viable approach.

After identifying the low-cost O&M strategy at each distance, we disaggregated results into their constituent parts to determine how OpEx and availability might realistically change with distance to port. Next, we fit curves to the OpEx and availability result data to describe the relationship among OpEx, availability, and relevant spatial parameters (e.g., logistical distances and metocean conditions). Figure 30 shows the disaggregated OpEx results, whereas Figure 31 shows the availability curves for each site type. For reference, the figures also show the economic break points among O&M strategies that were identified for the mild, moderate, and severe sites.

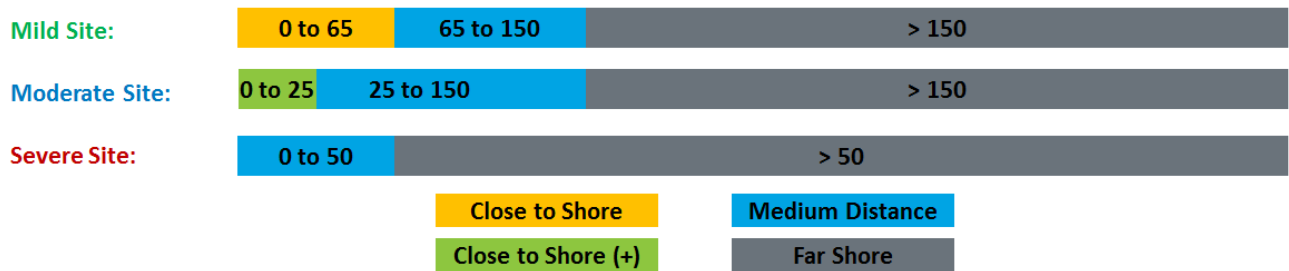
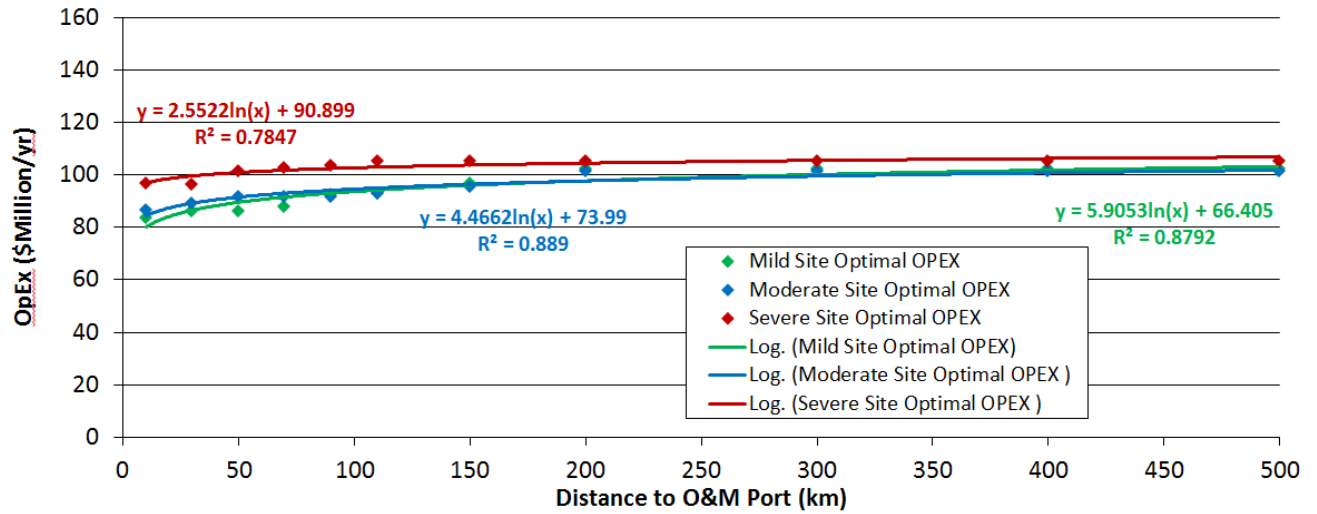


Figure 30. OpEx results for the fixed-bottom substructure

Note: Mild, moderate, and severe sites are denoted in km.

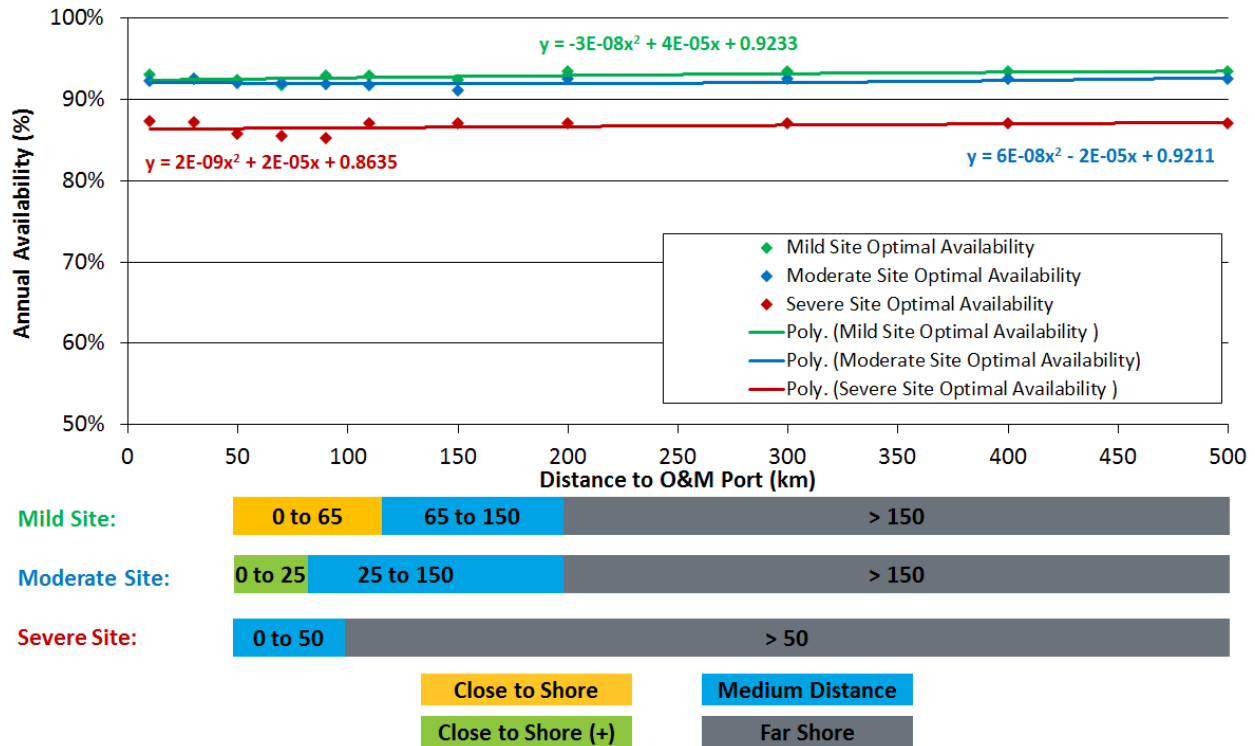


Figure 31. Availability results for the fixed-bottom substructure

Note: Mild, moderate, and severe sites are denoted in km.

Each of the representative sites shows similar trends. OpEx costs increase as the projects get farther from shore, but the slope tends to flatten out at greater distances because the far-shore strategy, which uses a mothership within the project as the base for most maintenance operations, is relatively cost-insensitive to distance. Availability is relatively flat across the parameter study, again because of the characteristics of the far-shore strategy. Note that the availability curves do not fit the output data well compared to the cost curves and may miss some of the trend at distances where the close-to-shore or medium-distance scenarios provide the low-cost option (<150 km at mild and moderate sites; <100 km at severe sites).

The severe site has significantly higher costs and lower availability than either the mild or moderate sites. This is because wind and wave conditions for this site exceed limits of 2.5 m Hs and 20 m/s wind speed more than 60% of the time. This limits the ability of technicians to access the turbine for inspection and maintenance. It also means that maintenance vessels and equipment will spend a considerable amount of time waiting on weather windows that meet criteria for the repair mission and at the project's expense. The combination of these factors means that turbines will remain down for longer after a failure event and that costs of repair will be higher than at a less severe site.

The conditions at the severe site, which characterizes many of the locations in the Pacific Ocean, extend beyond the offshore wind industry's experience. We recommend that O&M strategies for severe sites could be investigated in more detail to identify chartering strategies (e.g., clustered

repairs) or equipment capabilities that may reduce the delta among the severe sites and other locations.

6.3.6 Floating Substructure

The floating substructures considered in this analysis include the spar buoy and semisubmersible technologies. Each of these substructures considers a strategy for large corrective maintenance activities that involves a reversal of the installation process in which turbines are towed to port or suitable inshore assembly areas by an anchor-handling tug supply vessel, with assistance from two standard tugs, for major components to be replaced. All other inspections and repairs assume the use of technicians transported to the project site with support of a supply vessel when necessary. The floating substructures assume the same maintenance equipment used for the fixed-bottom (i.e., CTWs and cable-laying vessels); however, they assume a different equipment spread for major up-tower corrective maintenance because the floating substructure turbine can be towed to port or a suitable inshore assembly area. Additionally, activities such as mooring line repairs are considered for floating.

Analysts considered towing the turbine to shore for each of the floating substructures; however, the vertical-tow spar requires deeper waters and is towed to the project's inshore assembly area for a major component replacement, whereas the semisubmersible or horizontal tow-spar has less restriction on water depth and can be towed to the project's O&M base port. Therefore, the repair of a major turbine component placed on the spar is assumed to be conducted by a crawler crane placed on an offshore barge (similar to installation). If the turbine is placed on a semisubmersible, then the turbine can be repaired by a standard crawler crane at the portside. Because the repair equipment for the vertical-tow spar is assumed to be mobilized, the OpEx results are generally higher when compared to the horizontal-tow spar and semisubmersible. Results for the spar and semisubmersible substructures are presented in Section 6.3.6.1 and Section 6.3.6.2, respectively.

6.3.6.1 Spar (Vertical Tow)

The total annual O&M costs (OpEx + lost revenue) specific to the spar placed in the moderate site is shown in Figure 32. The spar's results for the mild and severe sites can be found in Appendix C.

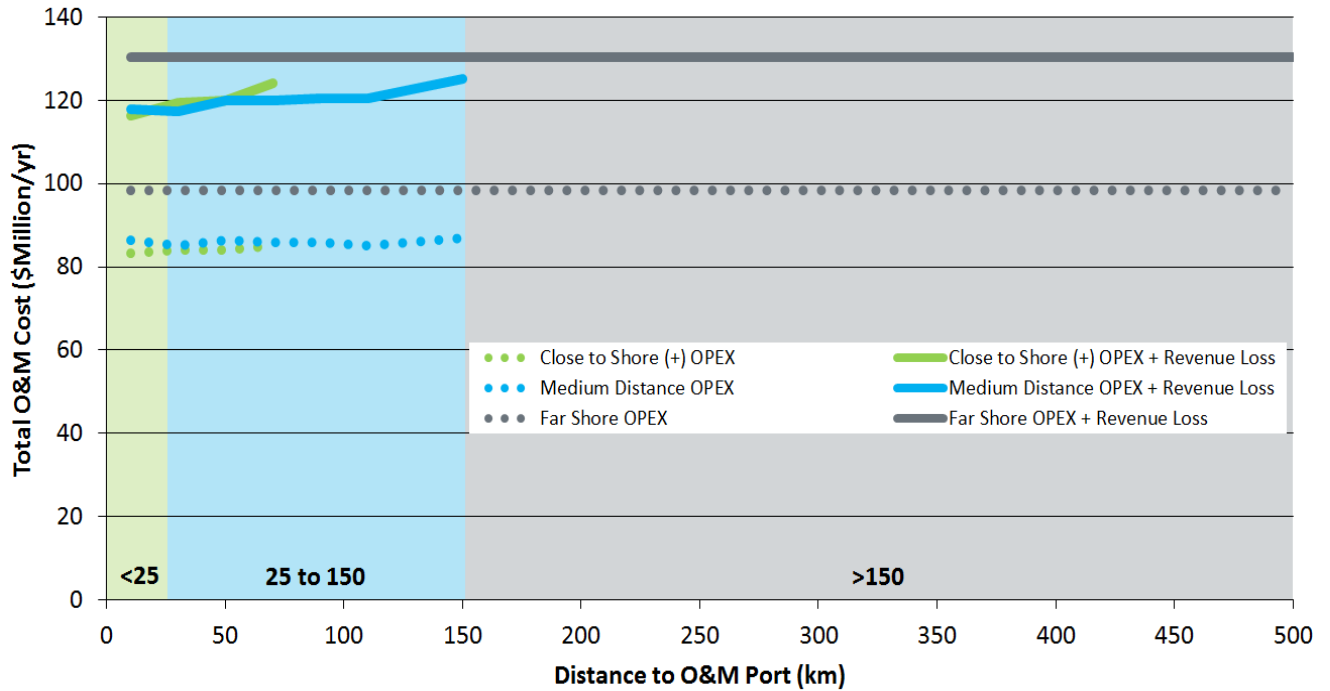


Figure 32. Moderate site total O&M costs for the spar substructure

Figure 32 illustrates the break points between O&M strategies: the close-to-shore (+) strategy for distances less than 25 km, medium-distance strategy from 25 km–150 km, and the far-shore strategy for distances greater than 150 km from port. Again, economics drive the break point between the close-to-shore (+) and medium-distance strategies, whereas excessive transport time drives the break point between the medium-distance and far-shore strategies.

Figure 33 and Figure 34 show the disaggregated OpEx and availability curves, respectively, for each site type for the spar in addition to the economic break points among O&M strategies that were identified for the mild, moderate, and severe sites.

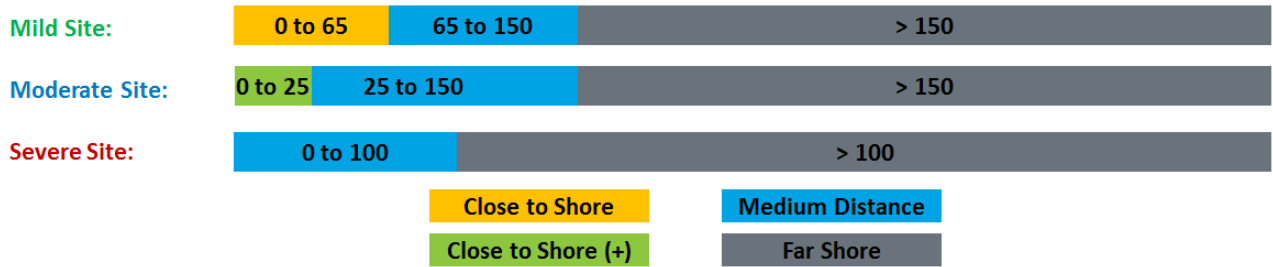
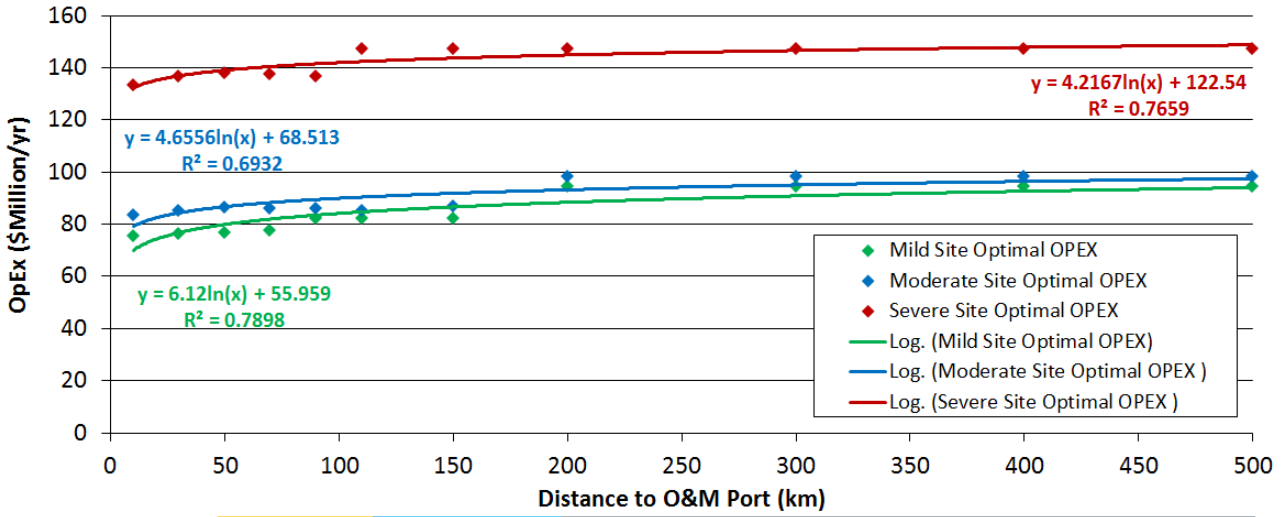


Figure 33. OpEx results for the spar buoy substructure

Note: Mild, moderate, and severe sites are denoted in km.

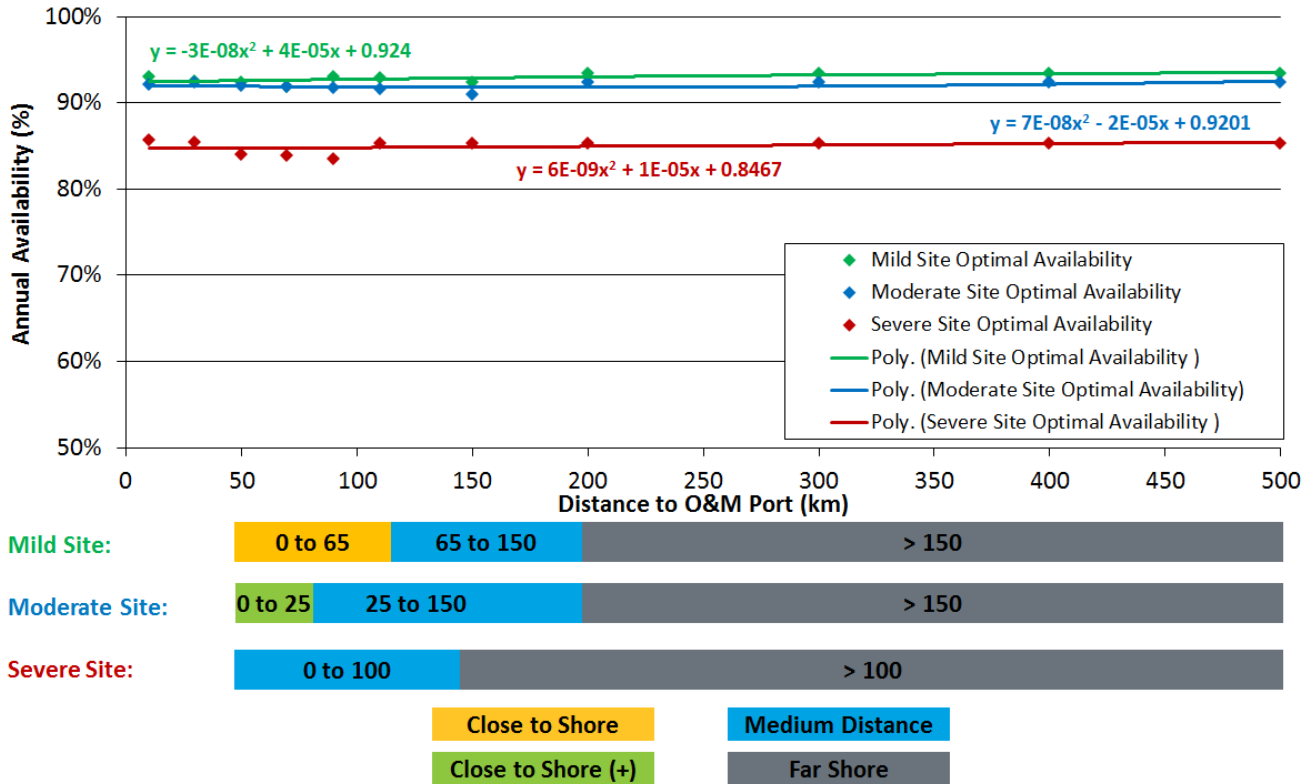


Figure 34. Availability results for the spar buoy substructure

Note: Mild, moderate, and severe sites are denoted in km.

Each of the representative sites for the spar buoy show similar trends. As described for the fixed-bottom substructure, OpEx costs increase as the projects get farther from shore, but the slope tends to flatten out at greater distances because in the far-shore strategy availability is relatively flat across the parameter study.

Again, the severe site has significantly higher costs and lower availability than either the mild or moderate sites. The higher cost is influenced by the limited ability for technicians to access the turbine for inspection and maintenance and the accrued waiting time for maintenance equipment during good weather windows.

One additional scenario for the spar buoy substructure was considered for the analysis. The additional scenario is a sensitivity that explores the option of towing the spar in a horizontal configuration versus vertically. This sensitivity assumes that there is no need to mobilize the inshore assembly area equipment; instead, the major turbine repair would be conducted by a standard crawler crane stationed portside. Details about the spar horizontal-tow sensitivity are described in Appendix C.

6.3.6.2 Semisubmersible Substructure

The total O&M cost results and economic break points for the semisubmersible substructure in a moderate site are presented in Figure 35. As with the other offshore substructure technologies,

the results for the semisubmersible in mild and severe metocean sites are presented in Appendix C.

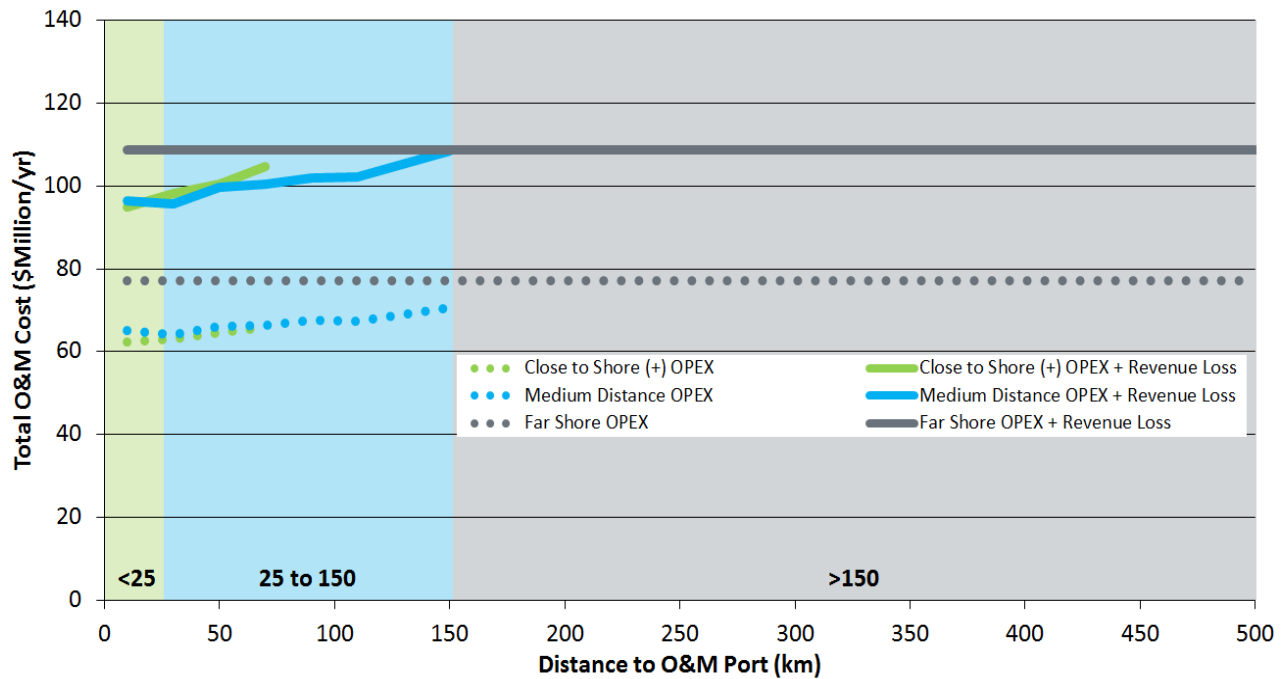


Figure 35. Moderate site total O&M costs for the semisubmersible substructure

The economic break points for the semisubmersible are similar to those of the spar buoy for moderate site conditions: the close-to-shore (+) strategy for distances less than 25 km, medium-distance strategy for distances greater from 25 km–150 km, and far-shore strategy for distances greater than 15 km from shore.

Figure 36 and Figure 37 show the disaggregated OpEx and availability curves, respectively, for each site type for the semisubmersible substructure. Also shown in the figures are the economic break points among O&M strategies that were identified for the mild, moderate, and severe sites.

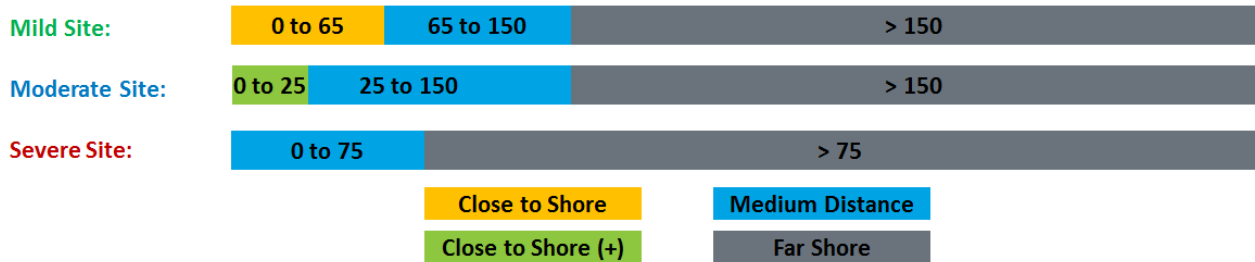
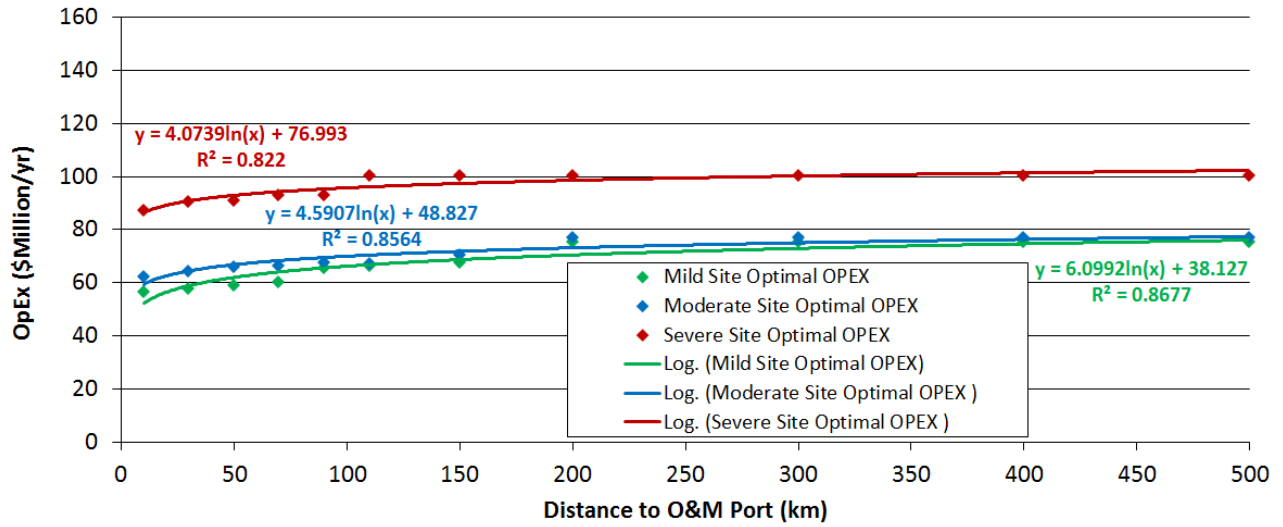


Figure 36. OpEx results for the semisubmersible substructure

Note: Mild, moderate, and severe sites are denoted in km.

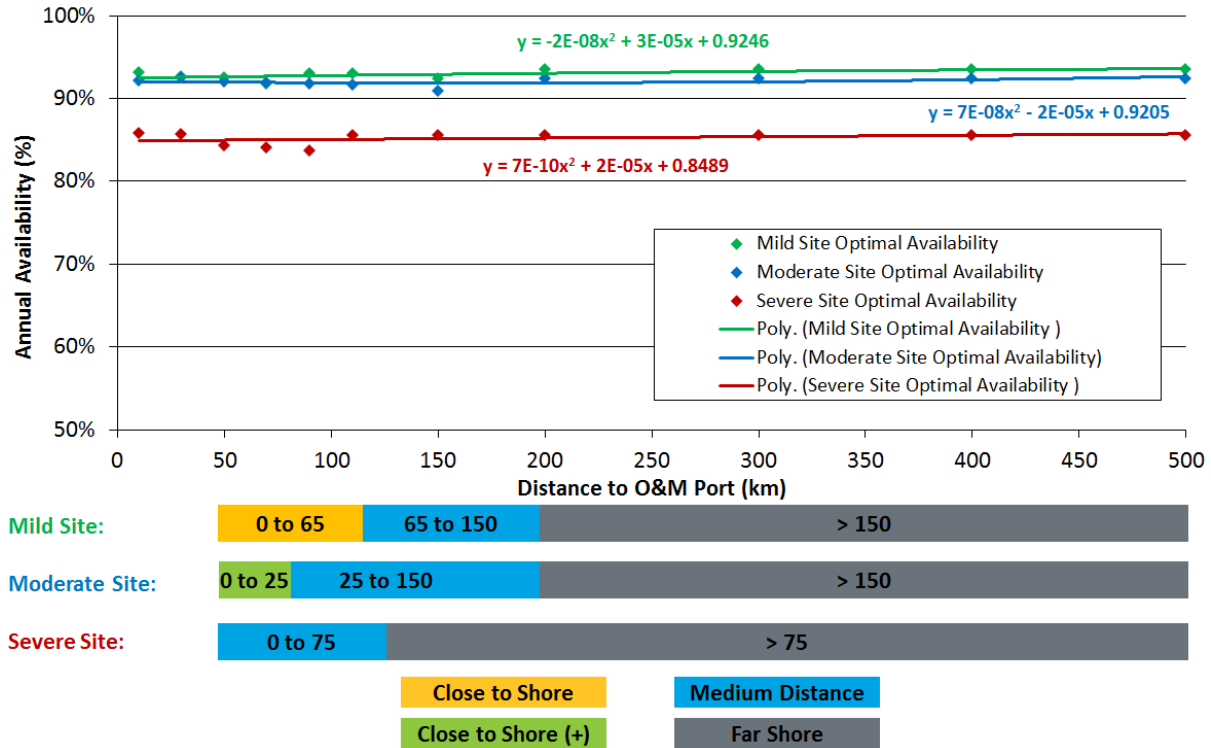


Figure 37. Availability results for the semisubmersible substructure

Note: Mild, moderate, and severe sites are denoted in km.

The semisubmersible has similar trends to the spar and results in a lower OpEx than the fixed-bottom substructures because the semisubmersible can be repaired at port.

The availability results for the semisubmersible are similar to the spar and show a large delta in availability between the moderate and severe sites. Further investigation into alternative O&M strategies and innovative vessel designs may reduce the availability difference between the sites.

We carried out the O&M analysis assuming a 6-MW turbine size for the O&M parameter studies. Consideration of other turbine sizes through parameter studies would add multiples of the current number of scenarios depending on the number of turbine sizes considered. Therefore, to analyze various turbine sizes ranging from 3 MW–10 MW without analyzing an additional number of scenarios, adjustment factors through cost multiplier equations are applied that relate the number of turbines to the overall maintenance effort. The cost multiplier adjustments were compared to other O&M studies by comparing the maintenance costs for variously sized turbines. However, these relationships should be investigated in the future through additional analysis of the impact of turbine size on maintenance cost by either running a limited number of cases to further refine the cost multiplier equations or by rerunning a full set of parameter studies for different turbine sizes and fitting complex multidimensional curves.

7 Cost-Reduction Pathways

7.1 Cost-Reduction Model

NREL's Offshore Wind Cost Model includes both the geospatial variables to address changes in LCOE across a wide geographic area and the time-dependent cost-reduction variables that assess future cost-reduction pathways. Because no single innovation can achieve the cost reductions necessary for offshore wind to compete long term, a set of innovations and supply chain effects is needed to achieve a total system cost reduction. In practice, multiple combinations of innovations lead offshore wind to a lower LCOE, and each set can be considered a pathway to the target cost. The model aggregates each set of user-defined inputs from 58 potential technology innovations and supply chain effects and estimates the resulting LCOE at two future focus years: 2022 (COD) and 2027 (COD), projected from the base year set at 2015 (COD). These estimates were examined at more than 7,000 sites throughout the U.S. technical resource area to provide estimations of how offshore wind costs might progress along specific cost-reduction pathways into the future. The main purpose of this analysis is to demonstrate that significant cost reductions are possible for both fixed and floating offshore wind turbines and to document the methodology for higher fidelity cost analyses in the future.

The portion of the NREL Offshore Wind Cost Model that relates to future cost-reduction pathways, or the temporal cost variables, was derived from the DELPHOS tool. DELPHOS was developed in the United Kingdom by BVG Consulting and KIC InnoEnergy (Valpy 2014). It builds from the Crown Estates' *Offshore Wind Cost Reduction Pathways Study* (2012) and copious expert European offshore wind experiences. The approach is a comprehensive bottom-up assessment of the potential to reduce cost from elements in the cost breakdown structure as well as by improving system reliability and performance. The model indicates that small but significant improvements in cost from each subassembly in the offshore wind system can lead to LCOE reductions of sufficient magnitude to achieve economic competitiveness, and these reductions can be shown in a transparent way. The DELPHOS tool applied data obtained from the Crown Estates 2012 study based on expert elicitations from 54 entities involved in the offshore wind industry and projected the Crown Estate FC 2020 cost targets out to FC 2025.

The maximum potential cost impact of each technical innovation under a best-case scenario was input into the DELPHOS tool while considering its relevance to specific site conditions (e.g., water depth and turbine size). The model takes into account that it may take years to achieve full commercial readiness and that innovations will be commercialized at different rates depending on their complexity, cost-reduction potential, and ability to demonstrate acceptable risk. Finally, the model requires the user to anticipate the potential market share of each innovation. In many cases, several innovations may be applied simultaneously to the same technology. To prevent the cost-reduction benefits of two incompatible technologies from being double counted, the DELPHOS tool has a market share control feature that prevents market share from exceeding 100% for any single subsystem (e.g., geared drivetrains and direct-drive generators).

In addition to technology innovation, most offshore wind cost studies also recognize that commercialization and supply chain maturity have their own unique cost-reduction pathways through increased competition, the learning curve, and the benefits of economies of scale. These are considered separately in the tool and are based on studies conducted by E.C. Harris (2012).

The 40 technology innovations, commercial-readiness, and market share assumptions that were used by DELPHOS (Table 13) were retained in the NREL Offshore Wind Cost Model under this preliminary assessment. This preserved the expert judgements that established the potential for cost reduction for each innovation. In addition, NREL identified some gaps that were not considered by the original DELPHOS tool. These gaps were addressed by creating new innovation categories and adding them to the DELPHOS tool. These new innovation opportunities include:

- Seven opportunities for electrical export cable infrastructure of the wind power plant's system performance
- Eleven alternative cost-reduction opportunities to address floating wind turbine technology.

The first version of the NREL Offshore Wind Cost Model uses the same focus FC years as the DELPHOS tool: 2013, 2020, and 2025, respectively. Assessments of costs that are made in any other year are based on interpolations or extrapolations from these reference FC years. For this study, the costs to 2030 (COD) were extrapolated to provide an approximation of the cost-reduction potential over a wider range. Although these costs were based on less rigorous analysis, evidence from historic rates of commercial maturity and market share growth in the wind energy industry suggests that during the 3-year extrapolation cost reductions are likely to continue.

7.2 Limitations and Caveats to DELPHOS Analysis

The cost-reduction pathway analysis presented in this report should be considered preliminary at the present stage. The main purpose of this analysis is to demonstrate that significant cost reductions are possible for both fixed and floating offshore wind turbines using expert elicitation and a system model to aggregate multiple cost and performance contributions. It will also be important to document the methodology so that higher fidelity cost analyses can be conducted in the future. The analysis tool does not yet provide enough resolution to establish pathways for specific technology components, but it can provide qualitative guidance to estimate the relative importance among various subassemblies in achieving cost-reduction goals.

The analysis inputs are strongly dependent on experience from land-based wind and the existing European offshore wind market. The methods that depend on expert elicitation have been shown in other studies to be a reasonable predictor of future outcomes (E.C. Harris 2012). This analysis has not independently verified the quantitative values provided in the DELPHOS bottom-up analysis; the general trends are supported by macroscopic economic indicators such as historic learning curves from similar industries that show that cost reductions of this magnitude can be reasonable under current market conditions (see, e.g., Bloomberg New Energy Finance [2015]).

As part of this analysis, additional innovations and cost-reduction opportunities were included in the DELPHOS analysis that did not undergo the same diversity of analysis as the original 40 Crown Estate cost-reduction areas. These additional cost-reduction areas are compelling for the possibility of significant floating offshore wind cost reductions, but due to lack of industry experience and the preliminary status of this analysis, there is a higher degree of uncertainty in the floating criteria presented.

Ultimately, the applicability to the U.S. market depends on supply chains and deployment rates that are similar to the current European offshore market and assumes that they would be replicated, although complexities with global trade from the European supply chains are not yet studied. Table 13 provides a list of all the variables used in the DELPHOS tool, including the variable added by NREL for floating wind and to fill gaps.

Table 13. Temporal Technology and Supply Chain Cost-Reduction Variables Used in NREL Offshore Wind Cost Model

	Temporal Cost-Reduction Variables	NREL Floating Innovation	NREL Innovation Addition
Nr	Development		
1	Introduction of floating meteorological stations		
2	Greater level of geophysical and geotechnical surveys		
3	Introduction of multi-variable optimization of array layout		
4	Greater level of optimization during Front End Engineering and Design (FEED)		
5	Introduction of reduced cable burial depth requirements		
	Turbine Rotor and Nacelle		
6	Improvements in blade tip speed		
7	Improvements in blade aerodynamics		
8	Improvements in blade design standards and processes		
9	Improvements in blade materials and manufacture		
10	Improvements in blade pitch control		
11	Improvements in rotor swept area to generator ratio		x
12	Array models, controls, optimization (A2e)		x
13	Introduction of inflow wind measurement		
14	Introduction of active aero control on blades		
15	Improvements in hub assembly components		
16	Improvements in mechanical geared high-speed drivetrains		
17	Introduction of mid-speed drivetrains		
18	Introduction of direct-drive drivetrains		
19	Introduction of superconducting drivetrains		
20	Introduction of continuously variable transmission drivetrains		
21	Improvements in workshop verification		
22	Improvements in AC power-take-off design		
23	Improvements in DC power-take-off design		
24	Optimized floating turbines	x	

Substructure and Foundation			
25	Holistic tower design		
26	Optimization of floating platform designs	x	
27	Improvements in floating hull design standards	x	
28	Improvements in floating hull manufacturing	x	
29	Optimization of mooring systems	x	
30	Shared anchors	x	
Array Cable System			
31	Improvements in array cable standards		
32	Introduction of array cables with higher operating voltages		
33	Introduction of alternative array cable materials		
34	Improvements and standardization of dynamic cables and hang-off equipment	x	
35	Mid-depth transfer systems	x	
Export Infrastructure			
36	HVAC and HVDC offshore transmission modules		x
37	Standardization of transmission and substation modules		x
38	Introduction of DC clusters shared between projects		x
39	Introduction of alternative export cable materials		x
Assembly and Installation			
40	Improvements in the installation process for Floating Support Structures	x	
41	Improvements in the range of working conditions for support structure installation	x	
42	Improvements in anchor installation techniques (industrialized for mass installation)	x	
43	Improvements in cable installation		
Operations and Maintenance			
44	Improvements in weather forecasting		
45	Improvements in inventory management		
46	Introduction of turbine condition-based maintenance		
47	Improvements in hull-condition monitoring		
48	Improvements in Operation, Maintenance & Service strategy for far-from-shore projects		
49	Improvements in personnel transfer from base to turbine location		
50	Improvements in personnel access from transfer vessel to turbine		
51	Introduction of wind power plant-wide control strategies		
52	Introduction of unmanned aerial vehicles for inspections		

Supply Chain			
53	Increased competition within supply chain (Europe/United States)		x
54	Increased competition from low-cost entrants (Asia)		
55	Economies of scale		
Contracting			
56	Vertical cooperation		
57	Horizontal cooperation		
58	Contract design		

Note: Data from NREL and Valpy (2014)

7.3 Floating Offshore Wind Innovations

Although floating offshore wind cost-reduction opportunities appear to be significant, they are different than fixed-bottom systems and require an augmented capital cost breakdown structure with some different assumptions. In the NREL offshore cost model, fixed-bottom and floating offshore wind are separated into two distinct technology classes; therefore, it was necessary to create a set of floating innovations corresponding to areas where technology advancements in this nascent sector have been focused (Musial and Ram 2010; Carbon Trust 2015; Catapult 2015). In the DELPHOS report by Valpy et al. (2014), each DELPHOS innovation was described in terms of its state of practice, its relevance to the baseline technology in the model, its commercial readiness, and its market timing and expected market penetration.

The floating offshore wind innovations that were added by NREL are described below:

- Optimized floating turbines:
 - Practice today: The few offshore floating turbines that have been deployed globally use wind turbines that have been designed to operate on fixed-bottom foundations.
 - Relevance: This innovation applies to all floating offshore systems.
 - Commercial readiness: This sector of the industry has not yet begun to develop due to the nascent stage of the industry. Turbine optimization is expected when market certainty is great enough to attract investment in new turbine technology.
 - Market share: The redesign and optimization of a purpose-built fleet of floating turbines requires a relatively large technical commitment from turbine manufacturers. It is anticipated that this innovation will be implemented after commercial markets emerge beginning in approximately FC 2025, with full industry participation by FC 2030.
- Optimization of floating platform designs:
 - Practice today: Floating platforms used on the early prototypes for floating offshore wind are adapted from oil and gas practices and rely heavily on concepts developed in fixed-bottom offshore wind. They have not functionally adapted yet to take full advantage of independence from bottom conditions, large vessel

construction, mass production and supply chain synergies, and quayside assembly and O&M.

- Relevance: This innovation is broad, but it applies to all floating offshore wind systems.
- Commercial readiness: This sector of the industry is developing at the prototype stage, but due to the nascent stage of the industry it has not gained any commercial maturity. Platform optimization is expected to precede turbine optimization, however, with platform designs that use conventional fixed-bottom turbines.
- Market share: Optimized platforms will evolve continuously. It is expected that commercial markets will adopt new platform technologies readily as they are demonstrated at the prototype and pilot scale by 2025.
- Improvements in floating design standards:
 - Practice today: International design standards for floating systems are immature and have not been validated with field experience in wind. They are adopted from oil and gas and fixed offshore wind.
 - Relevance: This innovation is broad, but it applies to all floating offshore wind systems.
 - Commercial readiness: Floating standards are essential for industry commercialization and regulatory compliance. Three-year cycles are common in standards writing. This does not appear to be a limiting factor yet, but reducing uncertainty in the design standards is a part of several cost-reduction pathways.
 - Market share: Currently all systems being designed comply with standards developed for other industries or fixed-bottom offshore wind. Floating offshore wind standards are expected to achieve full market adoption once written.
- Improvements in floating hull manufacturing:
 - Practice today: Current practices use existing oil and gas methods, which are based on single-unit production methods and tooling. Mass production and supply chain benefits have not been addressed. In addition, concrete floating hulls are now in design development and could affect local content.
 - Relevance: This innovation is broad, but it applies to all floating offshore wind systems.
 - Commercial readiness: This sector of the industry is an important part of the supply chain, but it has not yet begun to develop due to the nascent stage of the industry. Volume production is expected when commercial projects begin. Alternative hull materials such as concrete are likely to be introduced as early as 2018.
 - Market share: Commercial projects that may induce volume production of floating hull manufacturing may begin around 2025.

- Optimization of mooring systems:
 - Practice today: Standard oil and gas moorings and mooring line design and installation practices are being applied, but shallower water depths, different station-keeping requirements, lower investment risk (relative to oil and gas), and multiturbine arrays warrant a more modular and optimized approach.
 - Relevance: This innovation is broad, but it applies to all floating offshore wind systems.
 - Commercial readiness: Innovations on mooring systems may not be realized commercially until at least 2025, when larger commercial arrays are expected.
 - Market share: Commercial projects that may induce volume production of optimized anchors and mooring lines may begin around 2025.
- Shared mooring systems:
 - Practice today: This wind power plant design approach uses single-turbine independent designs.
 - Relevance: This innovation is broad, but it applies to floating offshore wind systems with catenary mooring systems at water depths where turbine spacing would not be significantly altered.
 - Commercial readiness: Shared mooring lines may be implemented in array designs where turbine layouts are compatible beginning in 2025.
 - Market share: Shared anchors may not penetrate the entire floating offshore wind sector, but they may become a significant lever to reduce cost in catenary moored systems by 2025.
- Improvements and standardization of dynamic cables and hang-off equipment:
 - Practice today: Dynamic cabling can add additional cost. Current systems are mostly custom designed.
 - Relevance: This innovation is broad, but it applies to all floating offshore wind systems.
 - Commercial readiness: This issue is addressed on individual prototype turbines, but further standardization may occur around a single solution to save costs with the introduction of commercial-scale wind power plants.
 - Market share: Market share will grow rapidly to 100% after industry supply chains are commercial.
- Mid-depth transfer systems:
 - Practice today: The current system used is identical to that of fixed-bottom offshore wind. Mid-depth electrical transfer systems are a potential way to reduce array cable lengths, but benefits are offset by the increased need for ancillary equipment. Innovation may have a negative impact on maintenance, but it would reduce losses.

- Relevance: This innovation applies to floating offshore wind power projects located in water depths greater than 200 m.
- Commercial readiness: Innovations on array systems may not be realized commercially until at least 2025, when large deep water arrays are expected.
- Market share: Commercial projects that may induce volume production of deep water arrays may be expected beginning around 2025.
- Improvements in the installation process for floating support structures:
 - Practice today: Preliminary cost analysis assumes that floating costs will be the same as fixed-bottom costs. Strong evidence supports lower costs for floating offshore wind installation and construction depending on the substructure technology and availability of marine construction equipment. This cost reduction is realized through less labor done at sea.
 - Relevance: This innovation is broad, but it applies to all floating offshore wind systems.
 - Commercial readiness: Some evidence suggests that all systems will use different lower cost installation methods for floating offshore wind (see e.g., Principle Power, Inc.⁴²).
 - Market share: Market share will be 100% based on the assumption that floating commercial wind power plants will use the least-cost options.
- Improvements in the range of working conditions for support structure installation:
 - Practice today: Preliminary cost analysis assumes that floating costs will be the same as fixed-bottom costs. Strong evidence supports lower costs for floating offshore wind installation and construction due to a lower sensitivity to weather disruptions depending on the substructure technology type.
 - Relevance: This innovation is broad, but it applies to all floating offshore wind systems.
 - Commercial readiness: Some evidence suggests that all systems will use different lower cost installation methods for floating offshore wind (see e.g., Principle Power, Inc.).
 - Market share: Market share will be 100% based on the assumption that floating commercial wind power plants will use the least-cost options.
- Improvements in anchor installation techniques (industrialized for mass installation):
 - Practice today: A few anchors are installed on individual turbines using conventional oil and gas practices. Commercial-scale wind projects will require hundreds of anchors at a time. There is a high potential for learning through scale and volume production.

⁴² Source: <http://www.principlepowerinc.com/>; Accessed July 2016.

- Relevance: This innovation is broad, but it applies to all floating offshore wind systems.
- Commercial readiness: Innovations on array systems may be realized when commercial-scale arrays are expected to be introduced, around 2025.
- Market share: Market share will be 100% based on the assumption that floating commercial wind power plants will use least-cost options.
- Other offshore wind innovations introduced by NREL:
 - In addition to the floating innovations described above, NREL identified other gaps that were not given sufficient attention in the original DELPHOS tool. These gaps were addressed by creating new innovation categories and adding them to the DELPHOS tool. These new innovation opportunities include seven opportunities for the electrical export cable infrastructure of the wind power plant's system performance. The original DELPHOS tool developed by Valpy et al. (2014) did not consider cost-reduction opportunities that extended beyond the offshore substation. As such, the export cable infrastructure was not considered in the scope, but it is a key cost item in the NREL Offshore Wind Cost Model.
- HVAC and HVDC offshore transmission modules:
 - Practice today: AC power cables connect individual wind projects to onshore grids through radial export systems.
 - Relevance: This innovation could apply to all commercial-scale offshore wind power projects that are located farther than 90-km from shore.
 - Commercial readiness: HVDC is available now. High-capacity power cables are being implemented in Europe now, but they are not considered part of the NREL baseline. HVDC will become commercial when large offshore projects are placed farther from the land-based grid connections.
 - Market share: Full build out of the offshore wind resource in key states will require remote placement of wind projects and some HVDC aggregation of power cables. Up to 50% of projects may use this technology.
- Standardization of transmission and substation modules:
 - Practice today: Substations are custom designed for individual projects and deployed as a standalone platform. New designs may integrate substations onto individual turbines and modularize them for volume production.
 - Relevance: This innovation could apply to all commercial-scale offshore wind power projects.
 - Commercial readiness: This technology will be available by 2020.
 - Market share: Wind project developers will likely adopt this technology. Full market penetration may take 10 years on new projects.
- Introduction of DC clusters shared among projects:

- Practice today: AC power cables connect individual wind projects to onshore grids through radial export systems.
- Relevance: This innovation could apply to all commercial-scale offshore wind power projects in close proximity to other wind projects where the aggregation of power cables may result in lower costs.
- Commercial readiness: This innovation may not be implemented immediately because it will add additional regulatory complexity and requires cooperation among competing developers. The primary barriers are not technical, but some engineering complexities may hinder maturity.
- Market share: Potentially, this innovation could become a valuable grid integration option wheeling power and managing large variable offshore wind loads. Low market penetration is expected before 2030.
- Introduction of alternative export cable materials:
 - Practice today: Standard export cables are made from copper conductors, and cable costs are high.
 - Relevance: This innovation could apply to all commercial-scale offshore wind power projects.
 - Commercial readiness: Transition to 66 kV has several benefits including lower array electrical losses. However, in order to realize this benefit, efforts must be made to overcome technical issues surrounding the implementation of such voltages.
 - Market share: The industry is trending toward the adoption of 66KV collector systems and HVDC export cables where distance and project scale warrant this approach.
- Increased competition within supply chain (Europe/United States):
 - Practice today: At present there are no commercial-scale projects in the United States, and the United States is reliant on Europe and Asia for significant offshore wind power project content in the first few projects, which is leading to higher initial costs.
 - Relevance: The innovation is relevant to all offshore wind power projects.
 - Commercial readiness: The U.S. market is expected to reach deployment levels at the gigawatt scale between 2020–2030. Benefits from increasing U.S. domestic content will be realized during this period.
 - Market share: The transition of greater offshore wind content and the development of a supply chain based in the United States is a primary challenge toward reaching cost targets. It is anticipated that this innovation will begin implementation with the first projects in 2020 and established U.S. supply chains by 2025.

8 Results

In this analysis, geospatial data layers (Section 4), wind power plant performance data (Section 5), spatial cost relationships (Section 6), and cost-reduction pathways (Section 7) were processed in a novel Offshore Wind Cost Model to derive cost parameters, including CapEx, OpEx, and AEP at a high geospatial resolution. These parameters were evaluated based on a defined LCOE equation (Section 3.2) and considered jointly with an initial estimation of available offshore wind revenue sources, or LACE (Section 3.3), to obtain an indication of economic viability for offshore wind and its geographic variability between 2015–2030.

Results were generated in the form of heat maps and tables. This section summarizes these results by providing a map of LCOE break points among fixed-bottom and floating technologies and heat maps for LCOE and economic potential for different U.S. coastal regions.

8.1 LCOE Break Points between Fixed-Bottom and Floating Technology

A significant determinant of offshore wind costs throughout the U.S. technical offshore wind resource area is the choice between fixed-bottom and floating technology. Section 2 describes four substructure technology types that were examined in this study: two fixed-bottom and two floating structures. Based on a cost-optimization algorithm in our Offshore Wind Cost Model, NREL determined the lowest cost option between fixed-bottom and floating technology at each of the 7,454 offshore wind sites assessed. Figure 38 depicts the break points among the fixed-bottom and floating foundation technologies.⁴³ Because of the shallower water depth, fixed-bottom technology is significantly more prevalent throughout the Eastern Seaboard and the Gulf of Mexico than it is along the West Coast, where water depths drop off from shore more rapidly. The results for the Great Lakes show only fixed-bottom foundation technology because floating technology is considered unfeasible at this time due to unacceptable high risks associated with survival under surface ice floes.

⁴³ This report does not present the details of the individual technology types (e.g., monopile versus floating semisubmersible) because this data was considered too preliminary at the time of this writing.

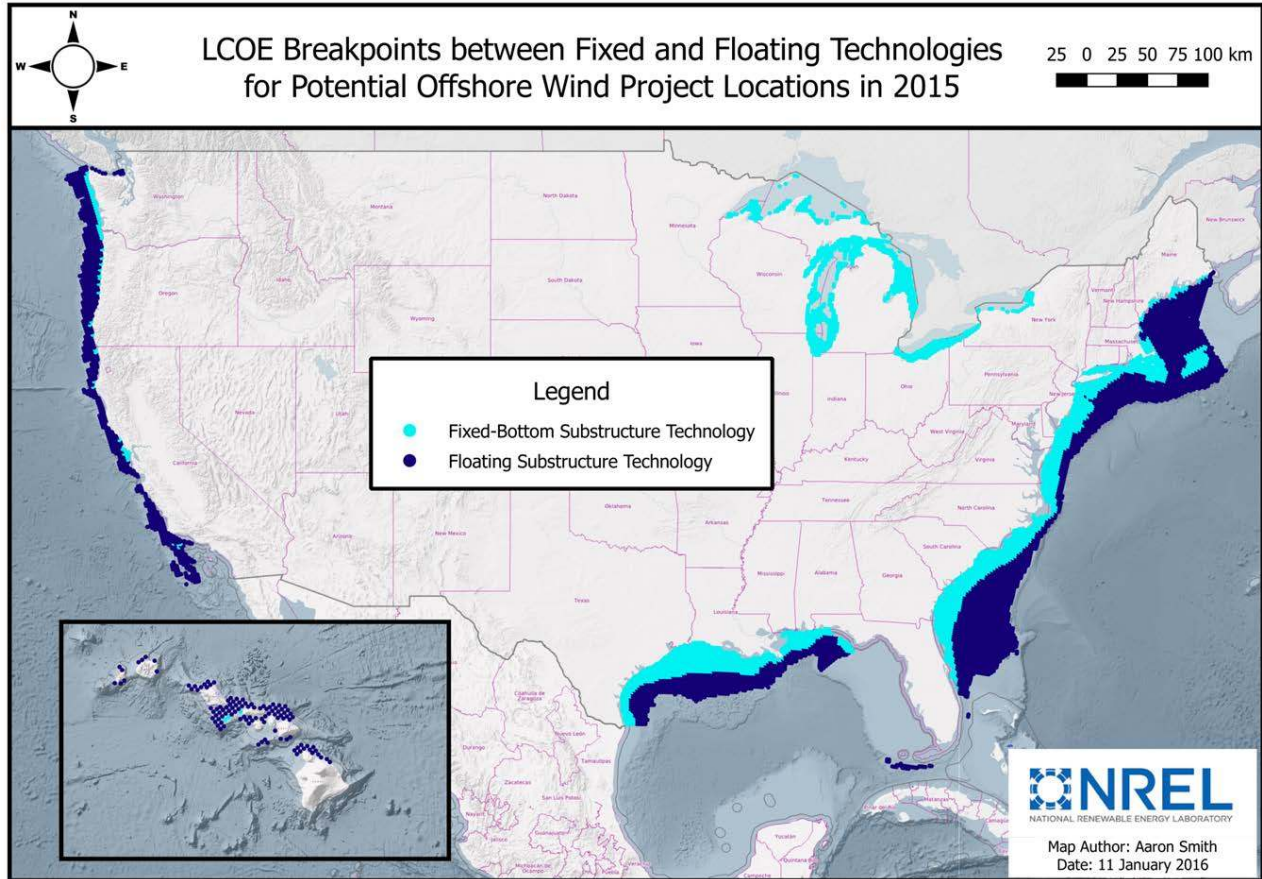


Figure 38. Estimated LCOE break points at U.S. offshore wind sites for 2015 (COD)

8.2 LCOE

LCOE is the principle metric of interest in this study; it indicates the costs to produce electricity at any given location and deliver it to the point of interconnection, excluding any subsidies. Cost reductions were estimated for 2015 (COD), 2022 (COD), and 2027 (COD). For the regional cost assessment (figures 39–43; Table 15), costs are reported for these three focus years. For the purpose of reporting the national results in the form of a cost-reduction curve and the cost-reduction scenarios (Figure 44, Table 14), data was plotted with an exponential curve fit through the modeled LCOE values (2015, 2022, and 2027 [COD]) for a time range 2015 (COD) through 2030 (COD). The LCOEs shown represent the optimal technology choice (e.g., fixed versus floating technology, substructure type) for a given site depending on spatial characteristics.

Figures 39–43 show the calculated LCOEs among U.S. coastal regions for the most competitive technology (i.e., cost-optimized substructure type) at each site, including the Atlantic Coast, Pacific Coast, Gulf Coast, Great Lakes, and Hawaii for the study focus years 2015, 2022, and 2027 (COD). In addition to some general caveats specified in Section 3 of this report, note that a number of simplifications have significant design variables that were not considered and should be treated with caution:

- Surface ice exposure will limit accessibility during winter months for projects in the Great Lakes and may have potentially large impacts on OpEx and availability. Surface ice floes may also necessitate structural modifications (e.g., ice cones).
- Hurricane exposure may have structural implications for turbines and substructures in the Gulf of Mexico through the mid-Atlantic regions, which may have impacts on OpEx (e.g., failure rates, insurance costs).

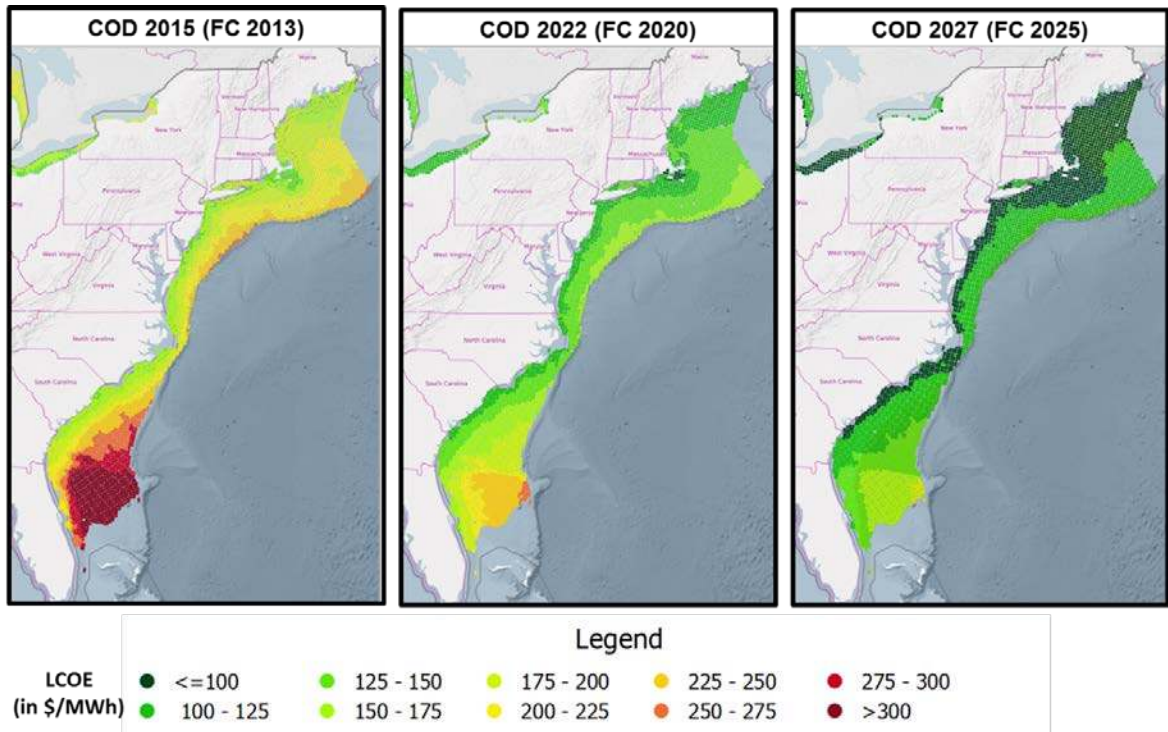


Figure 39. Estimated LCOE in the Atlantic Coast region

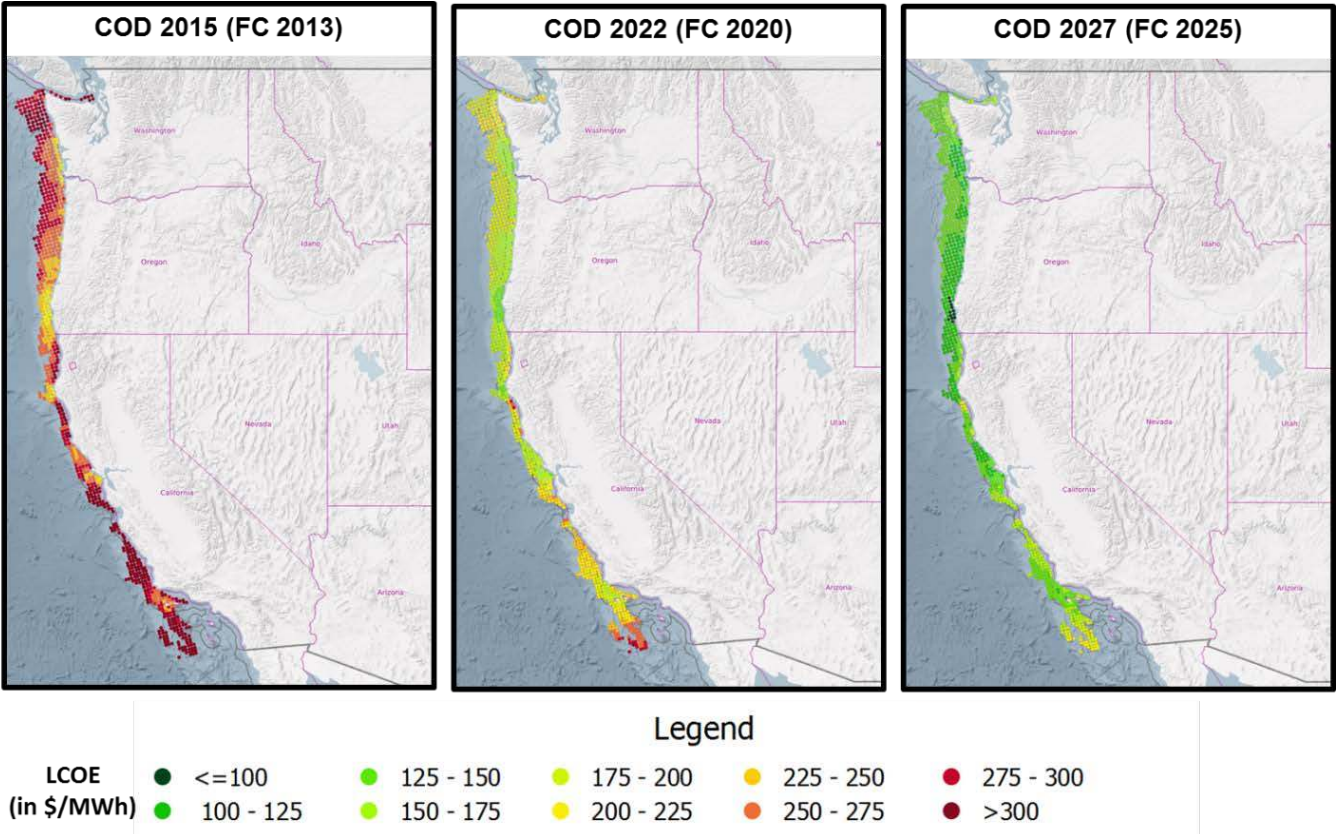


Figure 40. Estimated LCOE in the Pacific Coast region

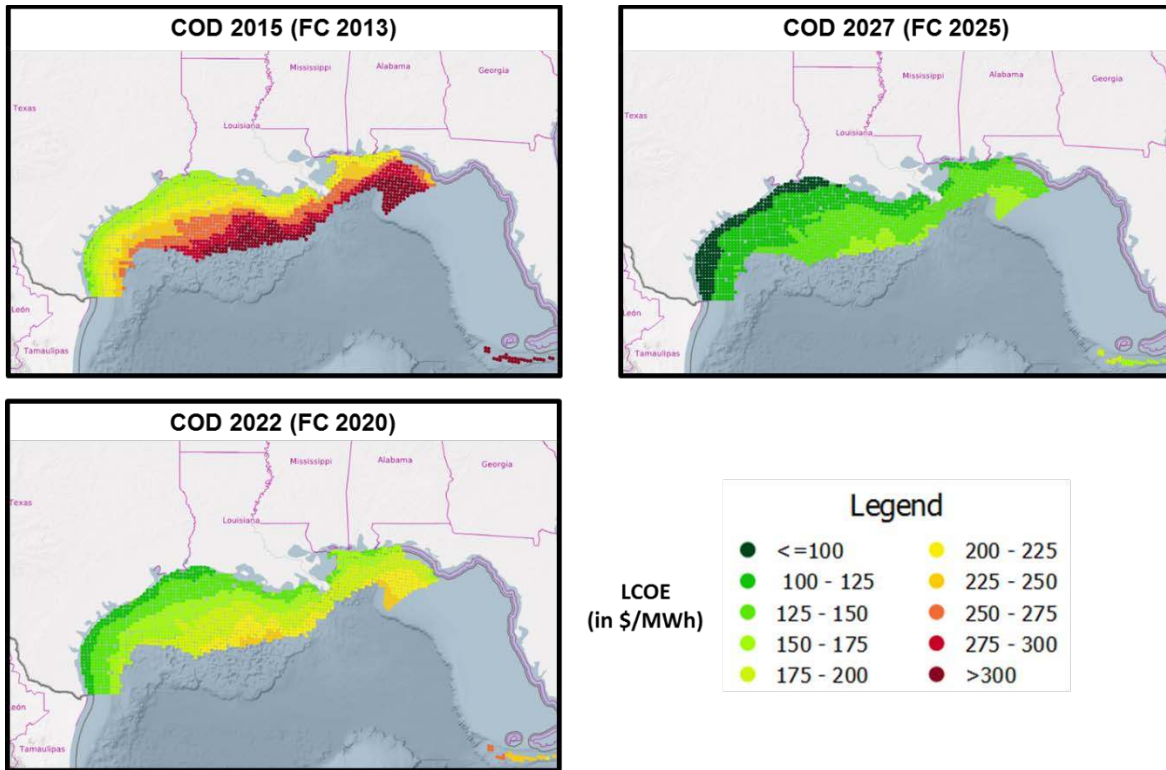


Figure 41. Estimated LCOE in the Gulf Coast region

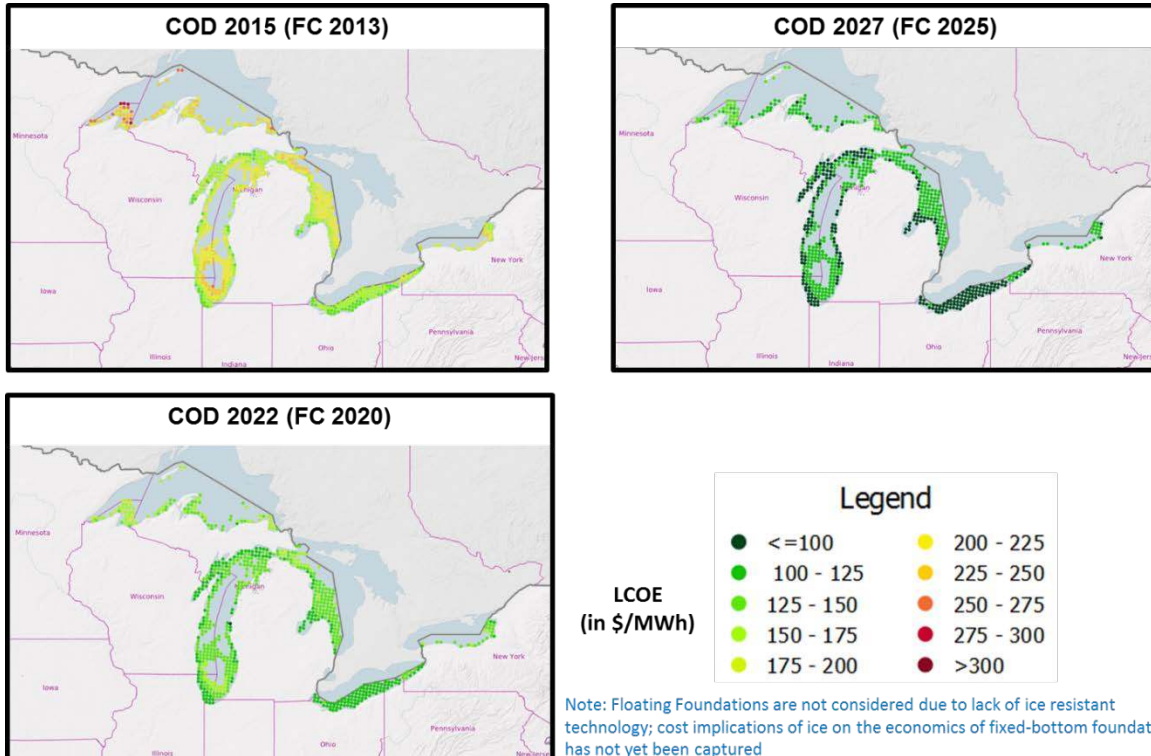


Figure 42. Estimated LCOE in the Great Lakes region

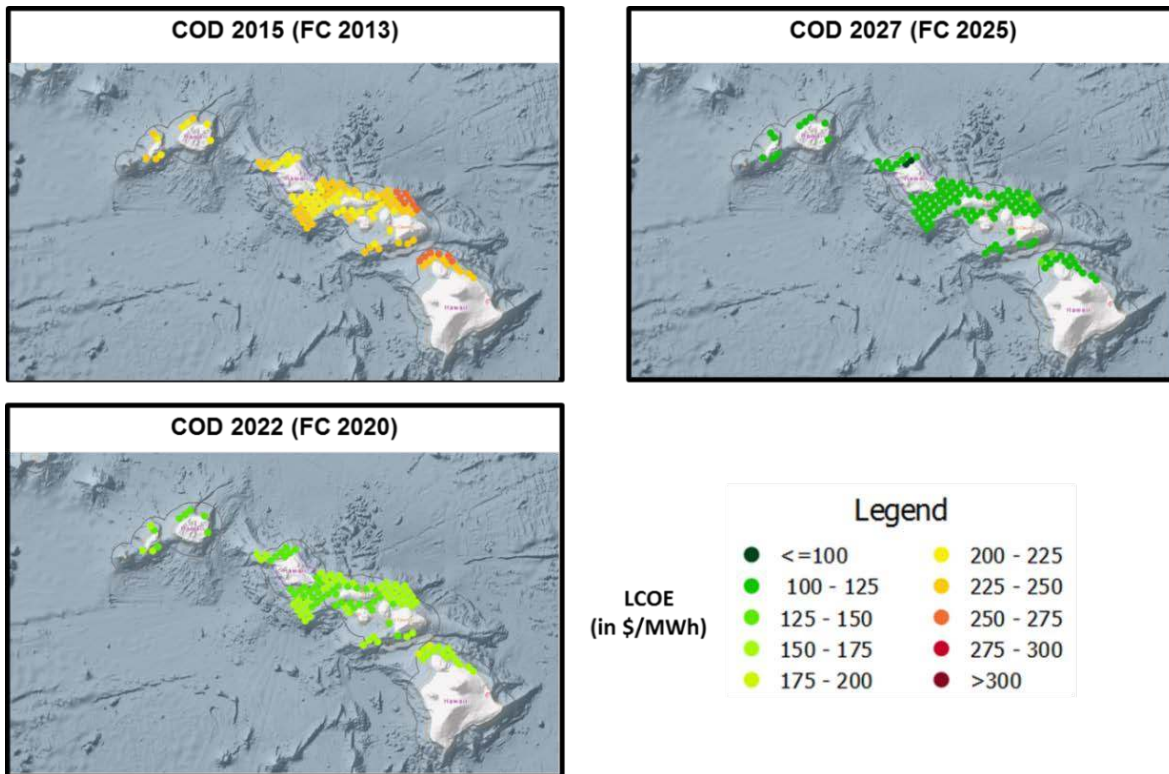


Figure 43. Estimated LCOE in Hawaii

8.2.1 LCOE in 2015 (COD)

In 2015 (COD), the lowest LCOEs in the country ranged from approximately \$130/MWh—to \$150/MWh, which can mostly be found along the coast of Massachusetts, the Great Lakes regions, and more sparsely scattered along the Eastern Seaboard and Texas. LCOE among U.S. coastal sites increases gradually to a maximum of \$450/MWh because the projects are sited farther from shore. Distance from shore is correlated with several major variables, including distance from cable landfall, water depth, and the severity of metocean conditions.

These promising locations—in the Eastern Seaboard, Great Lakes, and the Gulf of Mexico—share many common characteristics, including:

- Strong wind resources, ranging from 8.5 m/s–10 m/s, which result in net capacity factors between 40%–50%
- Close proximity to shore (less than 50 km), which minimizes electrical infrastructure and maintenance costs
- Adjacent location to an inshore assembly area (less than 300 km), which minimizes installation costs
- Shallower water depths, which minimize substructure costs.

Along the East Coast, LCOE ranges from 125\$/MWh–\$270/MWh in the Northeast and \$145/MWh–\$360/MWh in the mid-Atlantic regions, respectively.

The results show that the lowest LCOE in the Northeast region and the Great lakes region is approximately the same: at \$125/MWh in 2015 (COD). However, the range of LCOEs in the Great Lakes region is higher, with a maximum LCOE in 2015 (COD) at approximately \$300/MWh compared to \$270/MWh in the Northeast. The principal reason for the LCOE delta between the two regions is that the Great Lakes have a less energetic wind resource, with annual average wind speeds ranging from 8.0 m/s–9.5 m/s. The Great Lakes are relatively homogenous with respect to the physical variables considered in this assessment; the standard deviations for CapEx and OpEx are only 2% and 5% of totals, respectively. The variability of the wind resource within the region seems to explain the majority of the variations in LCOE; the best locations are in Lake Michigan and Lake Superior, which have strong wind resources in sites that are close to shore. Again, note that these results do not take into account the impacts of icing exposure on structural design, OpEx, or technical availability, which suggests that LCOEs for the region may be underestimated.

The lowest LCOEs in the Pacific region are approximately \$180/MWh in 2015 (COD) and range to up to \$450/MWh. The Pacific is characterized by generally strong winds⁴⁴ and deep water that is close to the shore—attributes that are favorable for floating offshore wind technology. The metocean conditions in the Pacific region are, however, much more challenging than those that the offshore wind industry has experienced in the North and Baltic seas in Europe. These metocean conditions, where the 1-year significant wave heights for sites among the region average 2.5 m, suggest that a high percentage of weather downtime is likely during marine operations. This weather downtime has implications for installation CapEx, OpEx, and availability losses, and it suggests that Pacific sites are likely to be more expensive than similar sites in the Atlantic or Great Lakes. Although it is beyond the scope of this study, NREL envisions that technical advancements in vessel design could address the challenges associated with severe meteorological ocean conditions and reduce the LCOE premium for Pacific sites.

8.2.2 Cost-Reduction Pathways

Figure 44 shows modeled reductions in LCOE over time for all U.S. offshore sites included based on the relationships and assumptions developed in Section 7. The upper range of LCOE estimates among all U.S. offshore wind sites showed decreases from \$450/MWh in 2015 (COD) to \$300/MWh in 2022 (COD), \$220/MWh in 2027 (COD), and \$190/MWh in 2030 (COD). The lower range of LCOE estimates among all U.S. offshore wind sites indicates decreases from \$130/MWh in 2015 (COD) to \$95/MWh in 2022 (COD), 80\$/MWh in 2027 (COD), and \$60/MWh in 2030 (COD). Figure 44 also includes two offshore wind cost-reduction reference scenarios for fixed-bottom and floating technology, respectively. The characteristics of these generic reference scenarios are specified in Section 3.2 to represent spatial criteria that are typically found in existing BOEM lease areas. However, note that the generic reference scenarios represent averages and do not reflect any specific BOEM lease area. The two reference scenarios follow the same general cost-reduction slopes that are reflected in the upper and lower boundary of LCOEs. Based on this NREL analysis, although the LCOE for floating technology is significantly higher in 2015 (COD), the two technologies are expected to converge over time (see also Table 14).

⁴⁴ Note that sites south and east of the Channel Islands generally have low wind speeds and may not be suitable for offshore wind project development.

Table 14. Estimated Potential LCOE Ranges for the Cost-Reduction Scenarios (Fixed-Bottom and Floating) between 2015–2027 (COD)

Cost-Reduction Scenarios	\$/MWh			
	2015 (COD)	2022 (COD)	2027 (COD)	2030 (COD) ⁴⁵
Fixed-Bottom	185	141	106	93
Floating	214	145	108	89

Note: Values are rounded and based on a defined scenario that assumes that the U.S. offshore wind industry can leverage the recent European offshore wind technology and industry experience while accounting for some significant physical, regulatory, and economic differences. The cost-reduction pathway under this scenario applies projected cost reductions developed for European projects and assumes sufficient deployment in the United States and domestic supply chain maturity to support these cost reductions during the analysis period from 2015–2027 (COD). Data is modeled for the focus years 2015, 2022, 2027 (COD), and an exponential curve fit is used for the 2030 (COD) data. The generic reference sites approximate the average site conditions at the current BOEM wind energy areas along the East Coast, but they do not represent any specific site. Policy or direct subsidies are not considered.

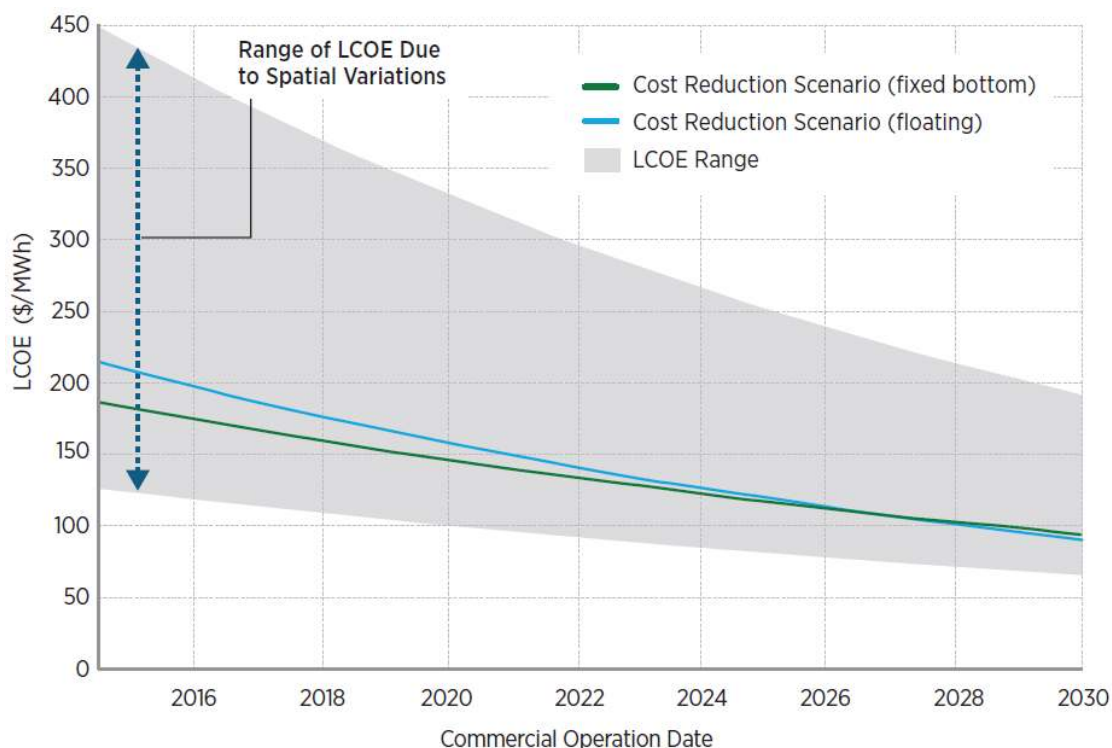


Figure 44. Levelized cost of energy (unsubsidized⁴⁶) for potential offshore wind power projects from 2015–2030 throughout the U.S. technical resource area

Note: Data plotted are an exponential curve fit through the modeled LCOE values (2015, 2022, and 2027 [COD]). The generic reference sites (“Cost Reduction Scenario”) approximate the

⁴⁵ An exponential curve fit through the modeled LCOE values (2015, 2022, and 2027 [COD]) allowed the calculation of an LCOE value for 2030 (COD).

⁴⁶ Without considering any potential impacts from policy (e.g., state renewable portfolio standards, production tax credits, carbon pollution and other greenhouse gas regulation, or loan guarantee programs); Accelerated depreciation (MACRS) is considered.

average site conditions at the current BOEM wind energy areas along the East Coast, but they do not represent any specific site

Regionally, note that the cost-reduction pathways determined in Section 7 were applied consistently to all U.S. offshore wind sites.

Table 15 shows the estimated LCOE ranges in different regions from 2015–2027 (COD). Between 2015–2027 (COD), LCOE decreases consistently among regions. By 2027 (COD), the lowest LCOE ranges from \$80/MWh–\$85/MWh, with the Pacific region and Hawaii showing a lower bound LCOE of \$100/MWh. The high end of the LCOE estimates among regions varies from \$130/MWh in the North Atlantic to \$220/MWh in the Pacific region.

Table 15. Estimated LCOE Ranges for Different U.S. Coastal Regions from 2015–2027 (COD)

U.S Coastal Region	\$/MWh					
	2015 (COD)		2022 (COD)		2027 (COD)	
	Low	High	Low	High	Low	High
North Atlantic	130	270	95	180	80	130
South Atlantic	145	360	110	250	85	170
Great Lakes	130	300	95	200	80	140
Gulf Coast	140	390	110	260	80	180
Pacific	180	450	130	300	100	220
Hawaii	200	270	130	180	100	130

Note: Values are rounded and based on a defined scenario that assumes that the U.S. offshore wind industry can leverage the recent European offshore wind technology and industry experience while accounting for some significant physical, regulatory, and economic differences. The cost-reduction pathway under this scenario applies projected cost reductions developed for European projects and assumes sufficient deployment in the United States and domestic supply chain maturity to support these cost reductions during the analysis period from 2015–2027 (COD). Policy or direct subsidies are not considered.

As discussed in Section 7, the analysis inputs for the applied cost reductions are strongly dependent on experience from land-based wind and the existing European offshore wind market. Ultimately, the applicability to the U.S. market depends on supply chains and deployment rates that are similar to the current European offshore market and assumes that they would be replicated, although complexities with global trade from the European supply chains are not yet studied. In addition, because of the lack of industry experience and the preliminary status of this analysis, there is a higher degree of subjectivity in the floating criteria presented.

8.3 Economic Potential

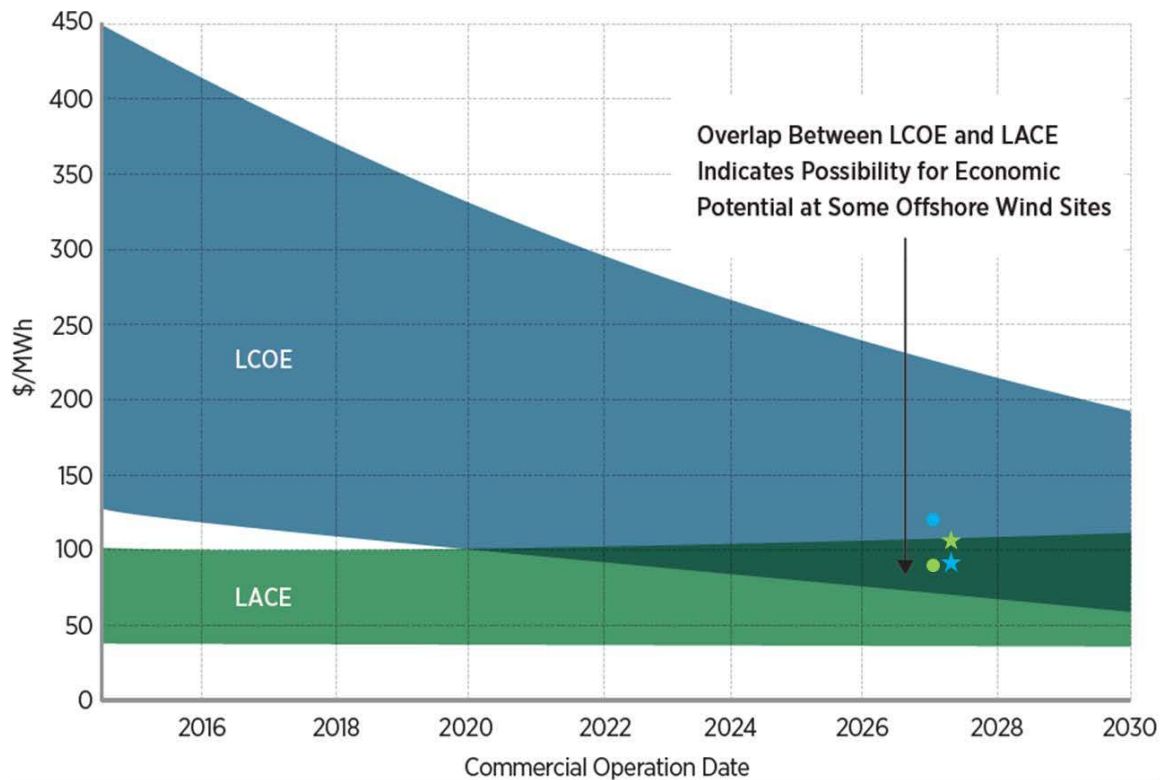
The LCOE assessment alone does not include a consideration of the policy, market, and regulatory factors that create demand for offshore wind within state or regional power markets. A subset of these factors related to markets are addressed in this study by comparing LCOE to the LACE metric, which has been described in Section 3. LACE can be used as a proxy for

available revenue to a potential offshore wind power project and captures marginal generation prices and capacity value at a given location.

LACE is generally predicted to increase gradually among U.S. coastal areas over time as a result of increased power generation and delivery costs (EIA 2015a).⁴⁷ These increases in LACE vary by region. Figure C-47 in Appendix C provides an illustration of the spatial variation in LACE estimates among U.S. coastal regions in 2025 (COD). The highest LACE can be found in the northeastern Atlantic coast because of relatively high electricity prices in that area. Moderate LACE can generally be found on the West Coast, and relatively low LACE can be found in the Southeast, Gulf Coast, parts of the northern Great Lake areas, and Northern California.

A comparison of LACE to LCOE can provide an indication for the economic viability of potential offshore wind power projects. If LACE exceeds LCOE at a given offshore wind location, it is an indication that the available revenue is greater than the required revenue. The associated capacity and electricity generation for that site can be counted as economic potential. Figure 45 shows the LCOE cost curve from Figure 44 with the corresponding LACE estimates for U.S. coastal sites. The figure indicates that as LCOE decreases and LACE grows marginally on average, the possibility for economic potential at some U.S. offshore wind sites grows over time.

⁴⁷ Although EIA (2015a) and other sources generally predict an increase in power generation and electricity delivery costs, a range of factors may influence future electricity costs, of which some are challenging to predict. These may include (but are not limited to) future developments in the energy efficiency, transportation, and storage sectors; changes in fuel prices and generation technologies; market structures; and macroeconomic factors.



- ★ ★ Stars illustrate an economically viable location in Massachusetts where LACE (green) is greater than LCOE (blue) in 2027 (COD)
- ● Dots illustrate an economically unviable location in Massachusetts where LACE (green) is less than LCOE (blue) in 2027 (COD)

Figure 45. Comparison of levelized cost of energy and levelized avoided cost of energy (unsubsidized⁴⁸) estimates from 2015–2030

Note: Data plotted are an exponential curve fit through the modeled LCOE values (2015, 2022, and 2027 [COD])

Figure 45 also illustrates the assessment of economic viability for two contrasting offshore wind locations in Massachusetts using floating technology. A set of markers (stars and dots) included for focus year 2027 (COD) show site specific LCOE and LACE estimates. The first site, indicated by dots, has a water depth of 926 m and has a distance of 264 km distance from site to cable landfall. Its LACE of \$93/MWh (green dot) compares to an LCOE of \$122/MWh (blue dot) in 2027 (COD); therefore, this location is not considered economically viable. On the other hand, the second site, indicated by stars, has a water depth of 221 m and a distance of 72 km from site to cable landfall. Its LACE of \$103/MWh (green star) compares to an LCOE of \$92/MWh (blue star) by 2027 (COD); because LACE is greater than LCOE, this location is considered to be economically viable by 2027 (COD).

While Figure 45 indicates national trends in LCOE and LACE over time, Figure 46 provides a site-specific assessment of economic potential. It shows that by 2027 (COD), in some areas

⁴⁸ Without considering any potential impacts from policy (e.g., state renewable portfolio standards, production tax credits, carbon pollution and other greenhouse gas regulation, or loan guarantee programs); Accelerated depreciation (MACRS) is considered.

within the U.S. offshore technical resource area LACE exceeds LCOE, indicating economic potential. In the near-term, these offshore wind sites are mainly located in the northeastern Atlantic Ocean and in a small number of locations along the mid-Atlantic coast. As discussed in more detail in Section 3, a set of assumptions and associated limitations will need to be considered with respect to the cost estimation, cost-reduction pathways, and LACE estimation. Most importantly, a full assessment of economic viability would incorporate a comparison of the offshore wind LACE/LCOE difference to other generation technologies to determine the technology that can provide the highest system value at lowest cost.

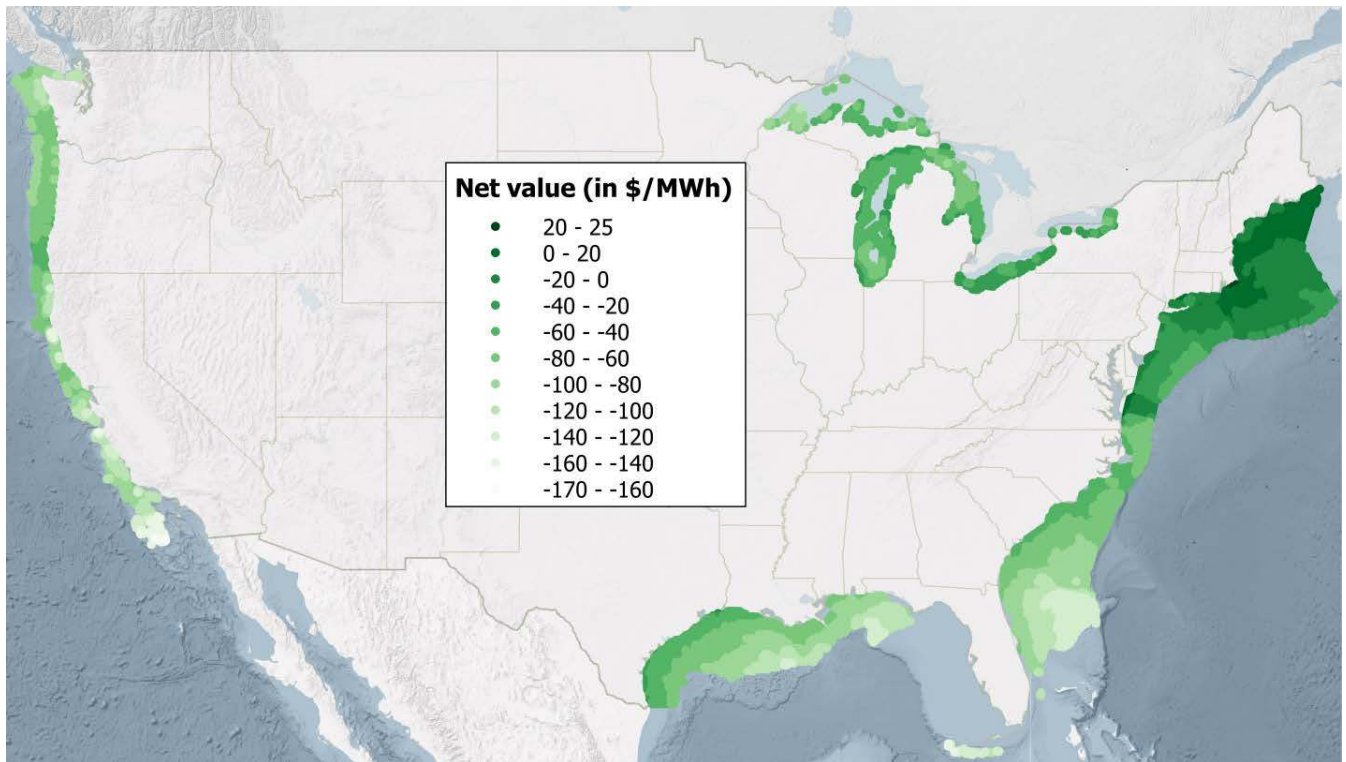


Figure 46. Economic potential (unsubsidized⁴⁹) of U.S. offshore wind sites in 2027 (COD)

Note: Net value captures the difference between LACE and LCOE and indicates economic potential as defined in this study. Hawaii is not included in this figure because of data limitations with LACE.

Figure 46 also illustrates that even a relatively small difference in either LCOE or LACE can make a considerable difference in terms of economic viability. This cautions us to interpret these results carefully (because of margins of error) and stresses the significant impact of regulatory, technological, or economic burdens or subsidies on the economic viability of offshore wind power projects. Policy makers at the local, state, and federal levels may choose to establish conditions that would enable deployment by providing incentives, such as tax incentive structures, offshore wind capacity carve-outs, or feed-in tariffs. For instance, the impact of the production tax credit has been estimated to reduce wind LCOEs (or, alternatively, increase LACE) by \$17/MWh (Bolinger 2014). Within the LACE/LCOE framework developed in this

⁴⁹ Without considering any potential impacts from policy (e.g., state renewable portfolio standards, production tax credits, carbon pollution and other greenhouse gas regulation, or loan guarantee programs); Accelerated depreciation (MACRS) is considered.

report, this can be thought of as reducing the LACE at a specific location by \$17/MWh, which would effectively increase the chance for economic viability at a given location. Such mechanisms could be used to support the deployment of above-market cost resources and may be motivated by considerations, such as environmental benefits, economic development benefits, and electrical system benefits. The gap between local LACE and LCOE could also be viewed as an approximation of the subsidy value that would be necessary to support initial deployment in any given year at a specific location.

9 Next Steps

Through the course of this study, several areas were identified where the analysis could be improved upon by additional research in the following categories: use analysis framework to refine insights into potentially favorable sites; address key limitations associated with the current analysis; and perform sensitivity analyses.

- 1. Use analysis framework to refine insights into potentially attractive sites that the current assessment identified for site-selection processes at the state and regional levels.**
 - A. Perform detailed analysis of output data set to provide additional insight into results for promising sites.
 - B. Evaluate promising sites by considering competing use and environmentally sensitive areas from the Black & Veatch (2010) data set as well as other information that NREL has collected.
 - C. Conduct more detailed demand-side analysis to explore market, political, and regulatory drivers for promising locations.
 - D. Perform additional analysis to clearly specify the optimal turbine design at minimal project cost at each of the offshore wind sites assessed.
 - E. Generate additional (graphical) output in the form of offshore wind supply curves that would indicate the available capacity at certain levels of LCOE and net value.
 - F. Conduct an analysis that takes into account the distribution of LCOE and LACE (e.g., density functions of LCOE and LACE), and perform an analysis that would redefine economic potential based on thresholds of LCOE and LACE distributions (e.g., compare 50th percentiles of LCOE and LACE for assessing economic potential).
- 2. Address key limitations associated with the current analysis.**
 - A. Develop or incorporate additional layers and/or analysis approaches to address spatial limitations:
 - i. Icing
 - ii. Hurricanes
 - iii. Geotechnical seabed conditions
 - iv. Extreme conditions (wind, wave, current)
 - v. Refine cost relationships (e.g., O&M modeling with different turbine sizes).
 - vi. Explore O&M strategies that could minimize the impact of the severe metocean conditions found at Pacific sites on LCOE. Perform analysis to identify chartering strategies (e.g., clustered repairs) or equipment capabilities that could reduce the delta between the severe sites and other locations.

vii. Develop national data sets and quantitative relationships to consider the relationship between foundation design and bottom conditions throughout the U.S. resource area.

B. Develop the cost-reduction pathway assumptions.

- i. Cost-reduction potential was adapted from Valpy et al. (2014); however, these cost reductions were not modified to correspond to specific U.S. characteristics (e.g., domestic supply chain) that may influence the cost considerably. Further analysis could identify reasonable assumptions about supply chain formation, manufacturing, and transportation to characterize the cost-reduction potential more accurately.
- ii. Cost-reduction potential for floating technology was based on an initial assessment. An assessment based on consultation with a wider group of experts or bottom-up engineering analysis could validate these assumptions.

C. Incorporate additional factors into the LACE metric.

- i. Consider competition among technologies, dynamic feedbacks from increasing renewable deployment on wholesale electricity prices, export or import situations, and new available data.
- ii. Include policy-related factors or subsidies as part of LACE, either nationally or in individual states. These factors may include renewable energy support mechanisms (e.g., the production tax credit, carbon pollution and other greenhouse gas regulation, state renewable portfolio standards, and loan guarantee programs), energy sector and environmental regulations, or benefits from portfolio diversification (EIA 2015b).

3. Perform sensitivity analyses.

A. For a more robust understanding of the cost and avoided cost components and their relationship to spatial parameters, a comprehensive set of sensitivity analyses can help us understand the impact from individual components.

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Appendix A. Overview of Geographic Information System Layer Development

The National Renewable Energy Laboratory (NREL) obtained geographic data from several publicly available data sets and commercial licenses. This appendix provides a more detailed account of the various geographic layers than could be presented in the main body of the report.

A.1 Wind Data

Wind data licensed from AWS Truepower consists of gridded data at a 200-meter (m) resolution, with separate shape files for annual, monthly, and diurnal distributions of wind speed and wind direction. Additionally, NREL utilized a previous data product licensed from AWS Truepower that includes binned capacity factor data on a 20-kilometer (km) grid. Analysts checked the gridded wind resource data against the Modern Era-Retrospective Analysis for Research and Applications (National Aeronautics and Space Administration 2014) data and National Oceanic and Atmospheric Administration (NOAA) buoy data (NOAA 2014) to ensure that mesoscale model results from AWS Truepower spatially aligned with available empirical information. Analysts then made scalar adjustments as necessary and processed these corrected data layers into wind resource grid files, which are used as inputs to the wind power plant performance modeling.

The input data for the wind resource grid files consist of AWS Truepower shape files of model output at a 200-m resolution. At NREL's request and to accommodate Openwind's native Universal Transverse Mercator (UTM) coordinate system, these shape files were to cover individual UTM zones 10, 11, 14, 15, 16, 17, 18, and 19. The actual product delivered by AWS differed slightly from initial specifications. No Zone 14 or Zone 16 shape files were delivered, but points from Zone 14 and western Zone 16 were found in UTM Zone 15, with coordinate values from Zone 15 merely extended to higher values not normally found in the UTM zone limits. Points in the Long Island region in UTM 18 were found in the UTM 19 files, with Zone 19 coordinates extended in the same manner.

Shapefiles for UTM zones 10, 11, 15, 17, 18, and 19 were used in the final processing. Points that would normally fall in UTM 14 were accessed from UTM 15 extended coordinates, and points in UTM 16 were accessed from UTM 15 or 17.

The wind resource grid file format was originally specified by the Technical University of Denmark for use in the WAsP wind flow and plant modeling software and is also the native wind map format used in Openwind. Wind resource grid files are normally created using linear flow models in software such as WAsP or Openwind and consist of frequency tables of wind speed and direction. In this case, analysts had to combine shape files for wind speed profiles and wind direction profiles into frequency tables of wind speed and direction. Wind resource grid files were created in blocks of 2-by-2 degrees, 6-by-6 degrees, and 10-by-10 degrees within each UTM zone to cover all of the offshore regions.

Parameters included in the processed wind resource grid files are as follows: wind speed, wind direction, wind speed frequency distribution by wind speed bin and direction sector, and wind direction frequency distribution by wind speed bin and direction sector. Figure 7 and Figure 8

show annual average wind speed and wind direction distributions across the U.S. offshore resource area, respectively.

A.2 Bathymetry

NREL obtained bathymetry data layers from the Bureau of Ocean Management (BOEM) Marine Cadaster (BOEM and NOAA 2014) and processed it to determine depths associated with the wind power plant placement grid. Parameters in the processed bathymetry files are included and grouped as follows: elevation from 0 m–10 m, elevation from -10 m–100 m, elevation from -100 m–300 m, elevation from -300 m–700 m, elevation from -700 m–1000 m, and elevation below -1,000 m.

A.3 Logistics

Locations and characteristics of U.S. ports were obtained from the 2015 World Port Index (NGA 2015). The ports were then filtered to identify those that may be suitable to support offshore wind power project development. World Port Index ports were filtered for access to open water, a channel depth of at least 7.9 m, and a shelter parameter of excellent, good, or fair to create a geographic information system (GIS) layer representing staging ports that may be suitable to support the deployment of spar, jacket, or monopile foundation technologies. Staging ports were further filtered to identify the subset of ports that do not have vertical clearance limitations (for at least part of the port). Note that quantitative data on both horizontal and vertical clearance limits are not available within the World Port Index; however, NREL visually inspected vertical clearances using Google Earth. Ports without overhead obstructions for at least part of the port were classified into the subset of staging ports with no overhead limits. Finally, because operational ports do not have to accommodate larger vessels or components, NREL made a subjective assessment of suitability and relaxed the channel depth filter for operational ports from a minimum of 8 m to a minimum of 5 m.

NREL identified potential inshore assembly areas through the inspection of geospatial data. Five inshore assembly areas were identified based on the following criteria: a minimum depth of 80 m at the inshore assembly area, a path to open water maintaining at least a depth of 60 m, and shelter from waves and currents. These inshore assembly areas include the North Pacific inshore assembly area in the Strait of Juan de Fuca near Seattle, Washington; the South Pacific inshore assembly area adjacent to the Channel Islands near Santa Barbara, California; the Atlantic inshore assembly area in Penobscot Bay near Searsport, Maine; the Oahu inshore assembly area off of Kāneʻohe Bay near Kahaluu, Hawaii; and the Hawaii inshore assembly area off of Hilo Bay near Hilo, Hawaii. Additionally, the Great Lakes appear to meet the criteria. NREL assumes that any location within the Great Lakes that is greater than 80 m deep could support assembly activities for floating spar technology.

Parameters included in the logistics files are as follows: latitude and longitude of ports, latitude and longitude of filtered ports, and latitude and longitude of inshore assembly areas. Figure 10 shows a map of these logistics points.

A.4 Grid Features

NREL identified potential interconnection points for each potential offshore wind power project from ABB's Velocity Suite database of existing energy assets in the United States (ABB 2014).

These interconnection points are used to approximate the amount of transmission line that would be necessary to reach the existing electricity grid from the point of cable landfall. NREL also uses the ABB database to provide a first-order approximation of the interconnection cost by identifying whether an existing substation can be upgraded or if a new substation needs to be built, given assumptions about existing utilization.

Parameters included in the grid features are as follows: interconnection point latitude and longitude (proprietary and not shared).

A.5 Meteorological Ocean

NREL obtained annual average information about meteorological ocean (metocean) conditions throughout the U.S. offshore technical resource area from the NREL marine and hydrokinetic (MHK) Atlas (NREL 2014). NREL also obtained time series information on metocean conditions for specific locations within the U.S. offshore resource area from the Wave Information Studies (WIS) program of the U.S. Army Corps of Engineers.

The MHK Atlas divides the offshore resource technical area into a total of 19,968 cells. Each cell is 4 minutes of latitude/longitude square (15 cells per degree, 225 cells per square degree). This analysis looks at only annual average significant wave height and average annual wind speed, although other variables are available. Figure 9 shows the average annual significant wave height in the United States. Note that the data in the Great Lakes region is extrapolated from a coastal wave height data set. The conditions in the center of the lake are largely unknown, though they are quite calm relative to the open ocean areas.

Analysts also extracted time series hindcast data for each of the WIS stations, which are available for periods of approximately 30 years at hourly or 3-hour intervals. Figure A-1 shows the WIS stations (time series data) overlaid on the MHK Atlas grid (annual average data) for the offshore resource area off the northwestern Pacific Coast.

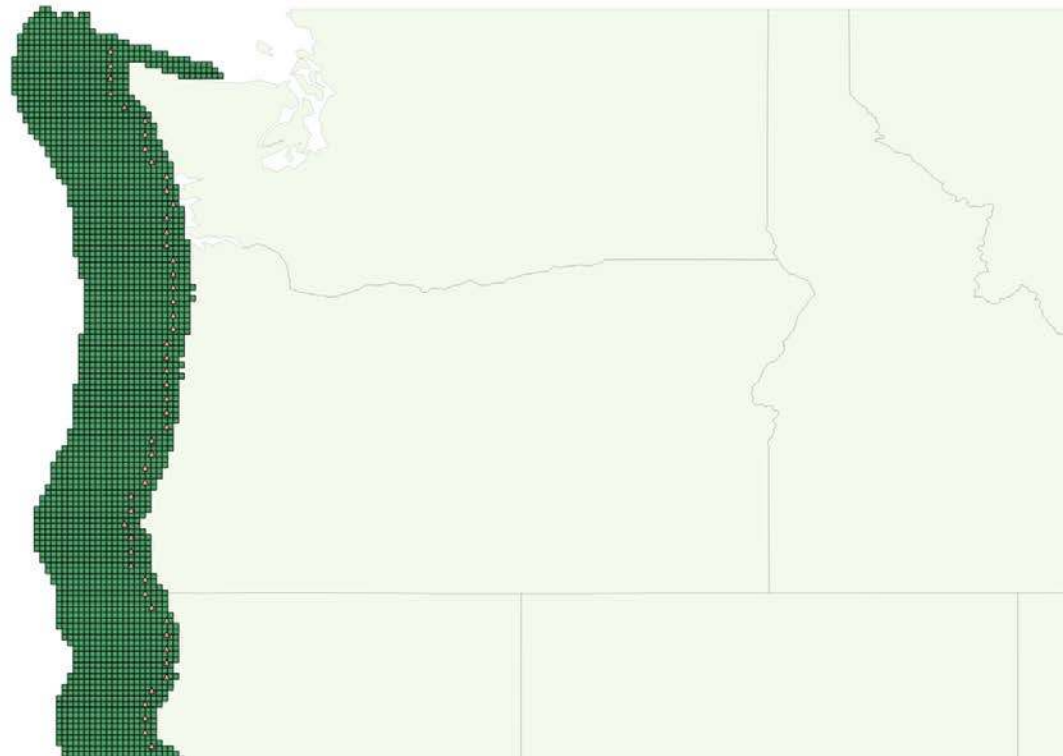


Figure A-1. WIS stations (triangles) overlaid on the MHK Atlas grid (green squares)

These data sets have a different resolution and provide information at varying levels of granularity. NREL considers them jointly in this analysis to inform the creation of two processed GIS layers. The first layer describes the percentage of time wherein weather conditions are likely to exceed operational limits for marine assets during the installation phase of any given project. This data layer is used to estimate the installation capital expenditures (CapEx) for each location. The second layer segments the resource area into three sites that represent the range of site conditions that offshore wind power projects may encounter in the United States. Each of these representative sites is associated with a WIS station that represents average site conditions. Data from each of these three WIS station are used to develop input files for the European Research Centre of the Netherlands (ECN) operation and maintenance (O&M) tool, which requires 10 years of correlated time series wind and wave data. This layer is used to identify which parametric curves best describe operational expenditures (OpEx) and availability for any project location.

Analysts developed weather downtime estimates using detailed time series data from each WIS site. Each WIS station was analyzed to create a joint distribution of wind speeds and wave heights. The weather information is scaled throughout the offshore resource area. First, the scaling algorithm assigns each grid cell to the nearest WIS station. Then the cumulative probability density function for the pertinent WIS station is scaled based on the ratio of annual average wind speed and wave height between the WIS station and the grid cell. Finally, the algorithm computes weather downtime for the grid cell based on the scaled joint probability distribution by estimating the proportion of time when weather conditions are outside of the

installation window, defined here as the period when wind speeds are less than 16 m/s and significant wave heights are less than 2.5 m.

The installation parameter study was conducted without considering weather downtime. The data processing framework applies site-specific weather downtime estimates to the gross installation CapEx estimate for each location to estimate total installation CapEx. Figure A-2 shows the installation weather downtime estimate for each location in the U.S. technical resource area. Note that there is no data for the Great Lakes because the wave resource data set does not cover these locations. Because metocean conditions within the Great Lakes are much less severe than those in open-ocean sites, this analysis assumes that there is zero weather downtime in these locations.

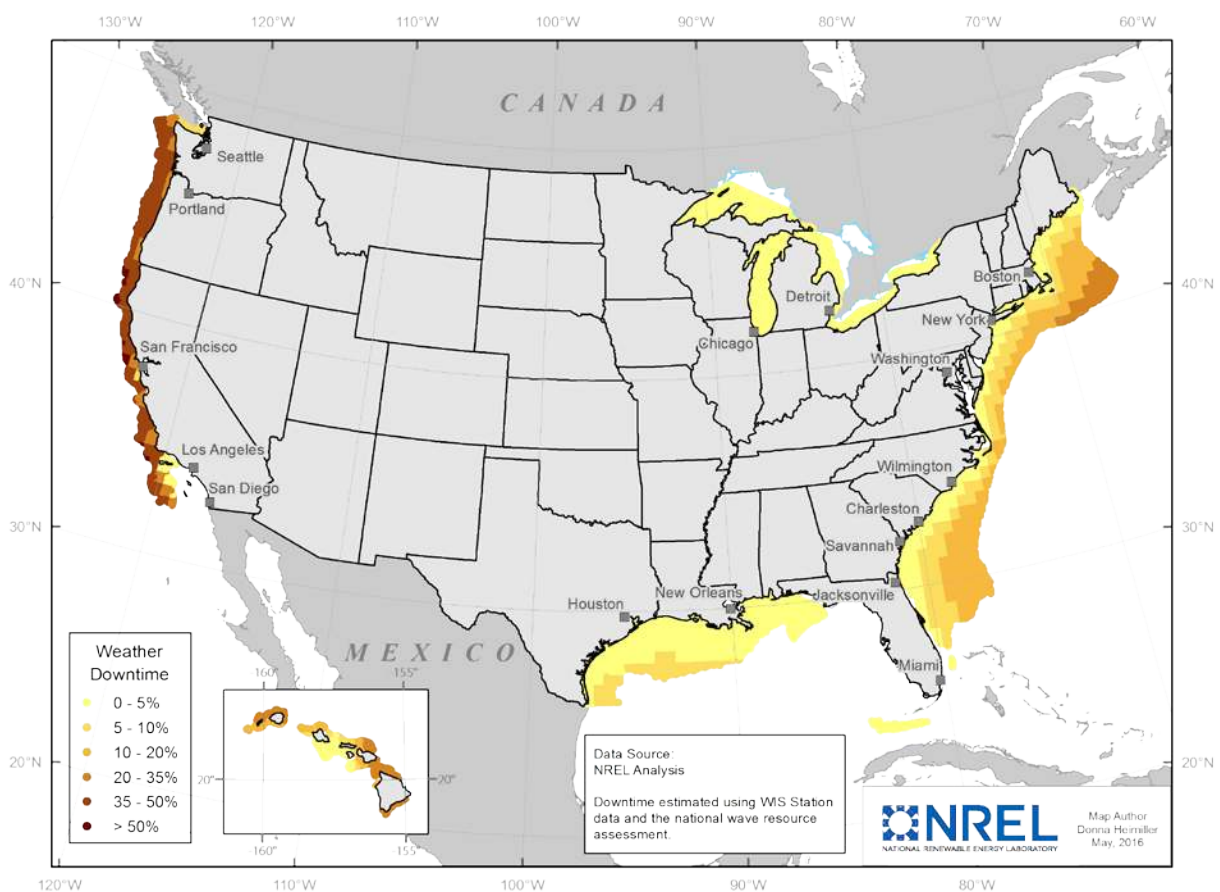


Figure A-2. U.S. weather downtime estimates for installation CapEx

The ECN O&M model requires detailed inputs on wind and wave conditions during a 10-year period. Time series data sets are not available for every location in the U.S. technical resource area, and the data processing requirements to conduct the O&M parameter study for each site would be immense. Instead of processing this data for each location, analysts decided to simplify the analysis by segmenting the U.S. offshore resource area into representative bins that could be represented by a single point. As a first step, analysts plotted annual average wind speed and

wave height data from the MHK Atlas in a joint distribution limited to sites with depths less than 1,000 m. Figure A-3 shows this distribution with a contour plot overlaid on the data.

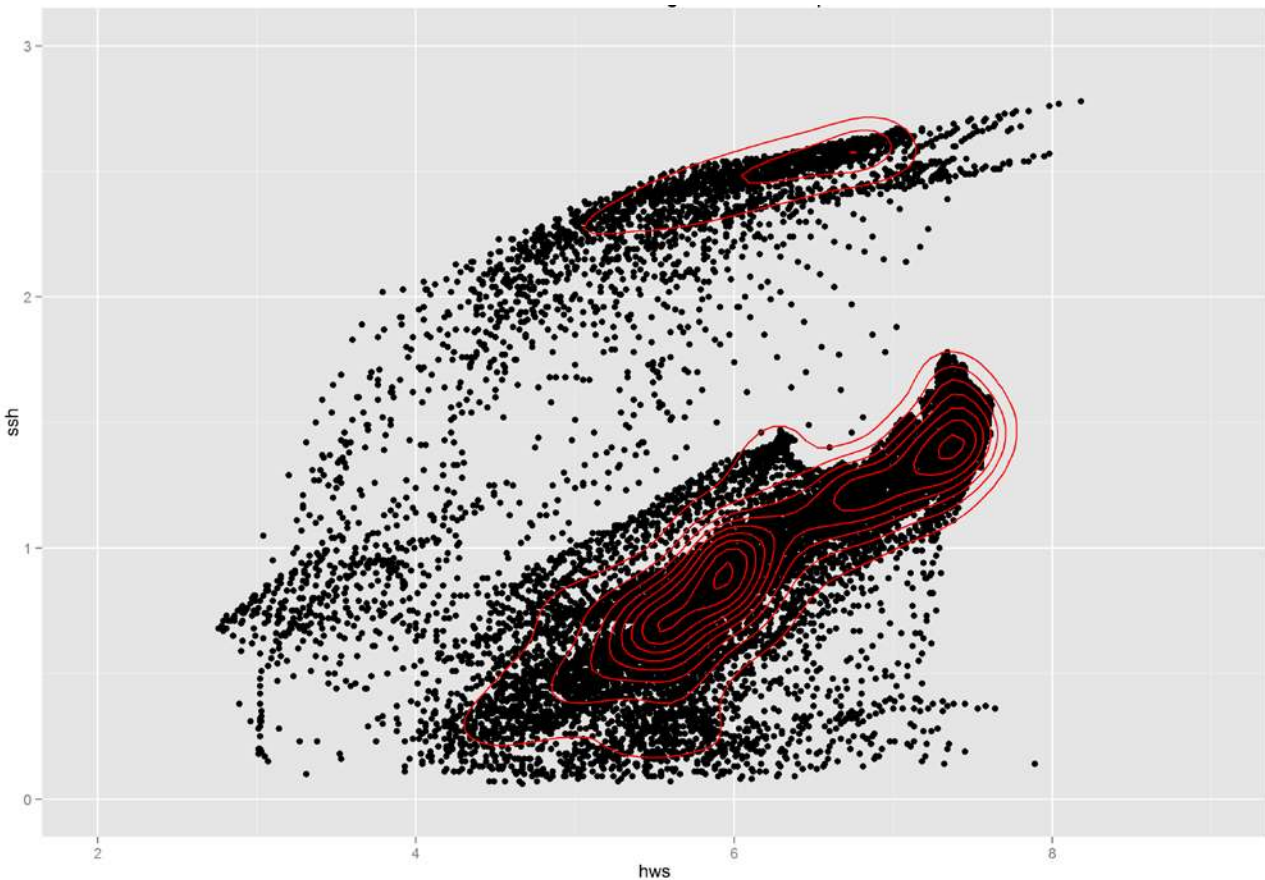


Figure A-3. Joint distribution of annual average significant wave height and wind speed (at sites <1,000 m)

This analysis shows three distinct local maxima. Analysts queried the WIS station data set to identify WIS stations that most closely matched the local maxima.

Table A-1 shows details for three sites selected to represent the mild, moderate, and severe metocean conditions, including the WIS site identification and geographic coordinates.

Table A-1. Details for Representative Wave Sites

Name	WIS Site Identification	Location Description	Latitude (Lat.), Longitude (Long.)	Average Significant Wave Height (m)	Average Wind Speed at 10-m Elevation (m/s)
Mild	73075	Southeast of Galveston, Texas	Lat. 28.950, Long. -94.500	0.88	6.12
Moderate	63080	Southeast of Nantucket, Massachusetts	Lat. 41.170, Long. -69.670	1.39	7.32
Severe	83038	Southwest of Gold Beach, Oregon	Lat. 42.330, Long. -124.670	2.50	6.61

Time series data for each of these locations are used to create three input decks for the ECN O&M tool. These input decks are used in the O&M parameter study, allowing analysts to capture how variability in weather conditions can impact O&M costs.

Each potential offshore wind power project location is assigned to one of the three O&M metocean conditions using a weighted least-squares method in which each 0.5-m Hs increment counts equally as a 1-m/s increase in wind speed. Figure A-4 shows the segmentation of sites into the three O&M metocean representative sites.

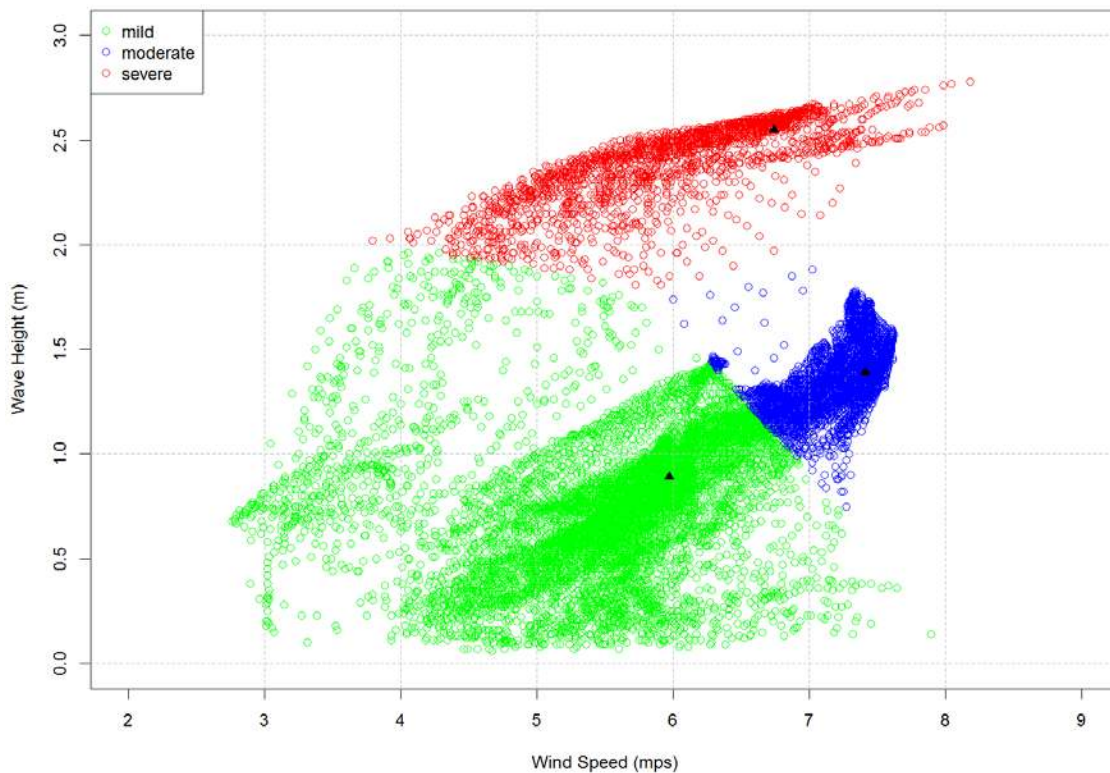


Figure A-4. Segmentation of sites into metocean conditions for O&M analysis

Figure A-4 shows the assignment of locations into metocean representative sites on a map. The severe locations all occur in the Pacific, and the moderate sites are predominately in the Atlantic, although some can be found in the Pacific. Mild sites are distributed among the Gulf of Mexico, Atlantic, and southern Pacific regions. Although the data set did not contain information about the Great Lakes, these sites are assumed to fall within the mild site because of the generally less severe conditions relative to open-ocean sites.

Note that in some locations wind speed is low, but annual average wave heights are high. These sites, which predominately occur in the southern Pacific region near Los Angeles, California, are assigned to the mild site. This may cause some bias in OpEx and availability results at these locations.

A.6 Areas of Competing Use

Areas of competing use are represented in a series of data layers that NREL obtained from Black & Veatch in 2009. Although Black & Veatch (2010) identified many important GIS data sources, much of the data needed to comprehensively characterize potential limitations on offshore wind deployment are not publicly available or could not be obtained within the study time frame. For example, other studies of smaller coastal zones in the United States have added exclusion criteria to account for sand-borrow areas, high-density avian flyways, and visibility from tourist areas with high economic value. Figure 12 shows the competing use and environmentally sensitive areas in the U.S. offshore region. Table A-2 lists layers included in the areas of competing use. To remain conservative in estimating LCOE, further reductions were assumed to account for visual impacts and other possible conflicts near shore (see section 4 for more details).

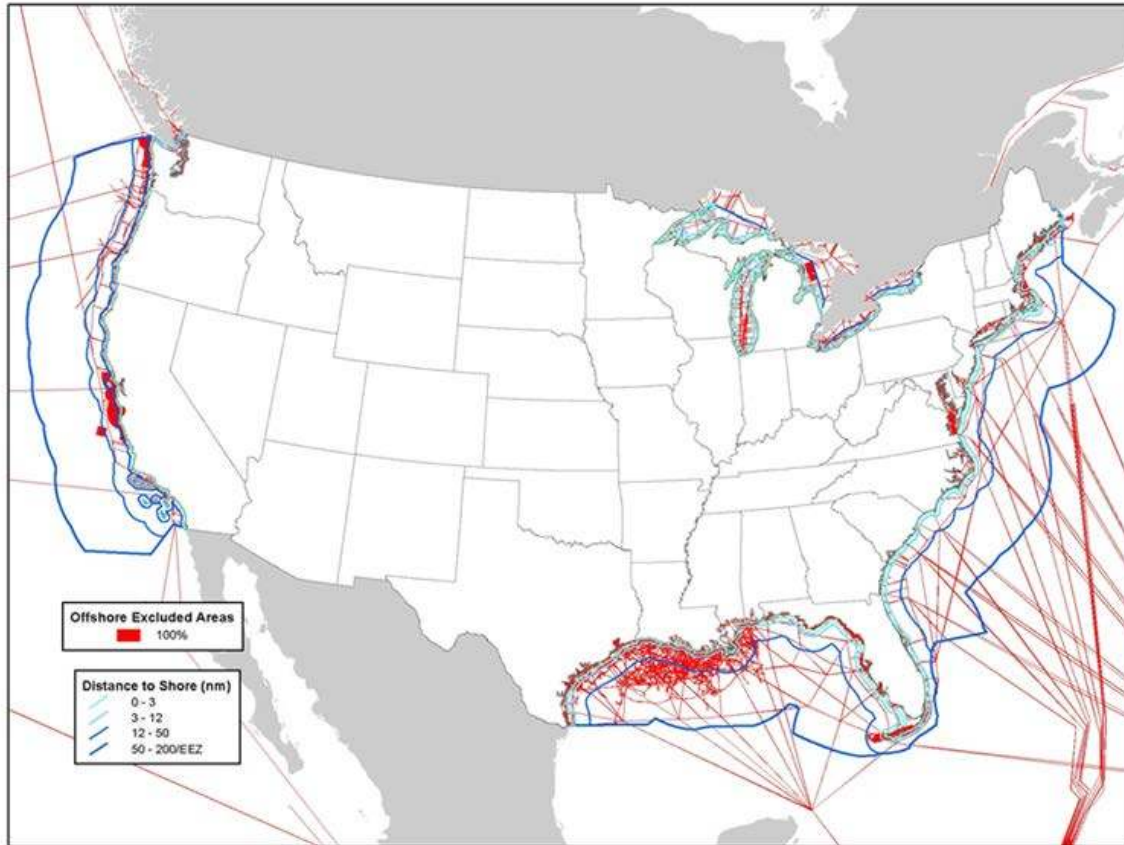


Figure A-5. Estimated excluded areas due to competing use and environmental exclusions. *Image from Black & Veatch (2010)*

Table A-2. Layers Describing Competing Uses and Environmental Exclusions

Layer Name	Layer Name
or_nearshoreBoundary	pac_efh_seagrass
wa_vegetationSkagit_1996	ca_stellarSeaLion
wa_salmonSteelhead	pac_ph_deis4efh_lessthan3500ft
wa_vegetationWhatcom_1995	pac_hapc_estuaries
pac_ecologicalPreserve	pac_hapc_canopyKelp
ocs_pac_leaseBlocks	pac_hapc_segrass
or_underwaterCables	pac_hapc_rockyReefs
ocs_EEZ_MMS	pac_efh_conservationAreas
pac_planningArea_MMS	pac_efh_groundfish_2
pac_tectonicStructures	wa_salmon
or_dredgeDisposal	ocs_shoreline_dtl
ocs_ports	pac_offshorePipelines_MMS
pac_oac_obstructions	pac_activeLeases_MMS
pac_3nmBoundary	pac_offshorePlatforms_MMS
pac_8gBoundary	pac_offshoreWells_MMS
pac_seabirdData_COASST	or_refuges_USFWS
or_ports	or_ESInearshoreBoundary
wa_marineShorelines	ocs_refuges
ocs_obstructions_AWOIS	pac_ih_protectedAreas
ca_cordellBanksClosedArea	or_energyProjects
ocs_mpa	wa_overwaterStructures
ocs_mpa_EXCLUDE	pac_ship_towlanes_2
ocs_shippingLanes_MMS	pac_ship_towlanes
wa_killerWhales	ocs_underseaFeatures
ocs_adminBoundaries_MMS	

A.7 Surface Sediment and Anchor Types

NREL processed existing surface sediment data at various resolutions to assign the closest sediment type parameter to each turbine location. Sediment types are used in this assessment to determine anchor types. Parameters contained in the surface sediment layer are as follows: gravel, gravelly mud, gravelly muddy sand, gravelly sand, mud, muddy gravel, muddy sand, muddy sandy gravel, sand, sandy gravel, sandy mud, slightly gravelly mud, and bedrock. Parameters contained in the anchor type layer are as follows: drag embedment anchor and suction pile anchor.

Figure A-6 shows the available surface sediment data for the U.S. offshore technical resource area.

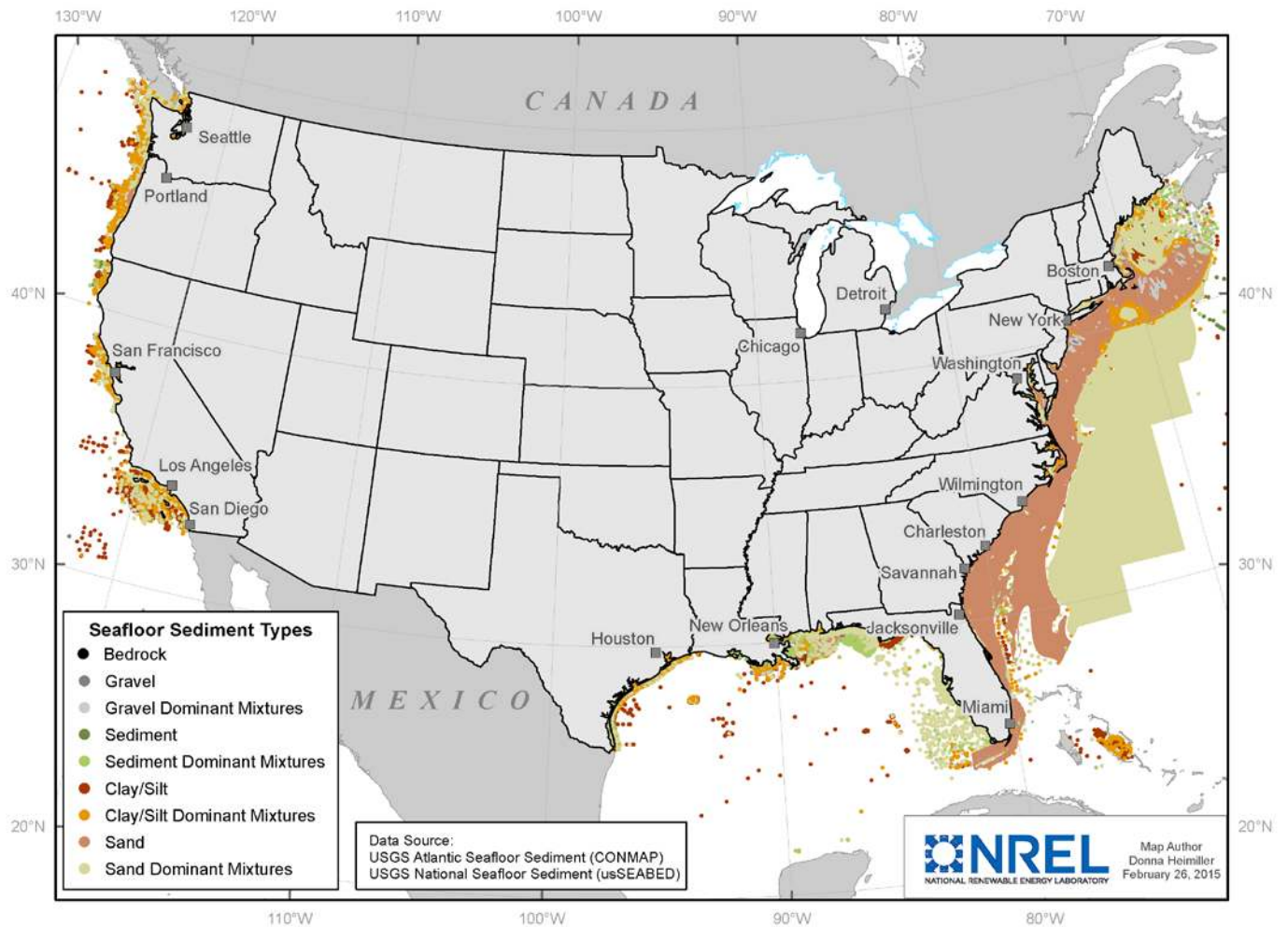


Figure A-6. U.S. surface sediment layers

A.8 Regional Cost Multipliers

In addition to the base capital cost for each representative wind power plant, this analysis imposes regional cost multipliers that are intended to reflect the impact of remote location costs, costs associated with seismic design that might vary with region, and labor wage and productivity differences by region. Figure A-7 shows regional capital cost multipliers based on cost multipliers developed by Science Applications International Corporation for use in electric sector capacity expansion modeling (Beamon and Leff 2013). The multipliers have been adjusted so that Massachusetts is the index value; the original cost that underpins this assessment was developed for the 600-megawatt (MW) commercial-scale scenario. These multipliers are organized based on the regions used in the Renewable Energy Deployment System (ReEDS), NREL's capacity expansion model. Note that the ReEDS model does not cover Hawaii, and to account for this lack of representation, NREL assigned Hawaii with cost multiplier values equal to that of one of the more expensive regions in the ReEDS model. Although such a technique is appropriate for Hawaii, it is thought to potentially underestimate the costs of developing offshore wind power projects in this expensive region.

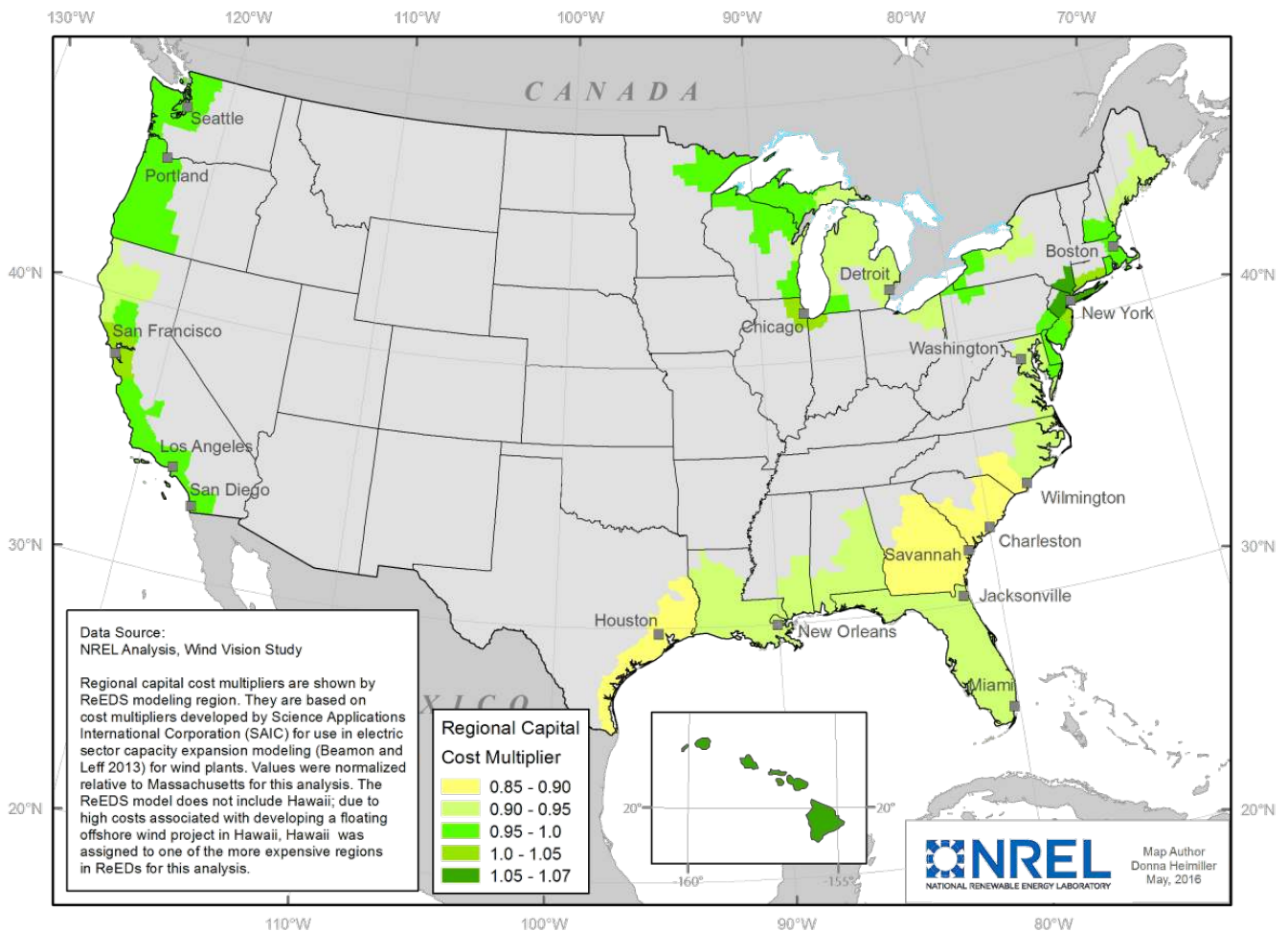


Figure A-7. Regional CapEx multipliers

Regional spur line costs are used to connect the project to the existing electrical grid from the point of cable landfall. Regional spur lines are assumed to have a base cost of \$3,667/MW-mile to build a 230-kilovolt line (Eastern Interconnection Planning Collaborative [EIPC] 2012). The costs of building transmission change considerably based on region and are subject to a different set of regional cost multipliers derived from Eastern Interconnection Planning Collaborative EIPC (2012). Figure A-8 shows the cost of building spur transmission lines after accounting for regional multipliers.

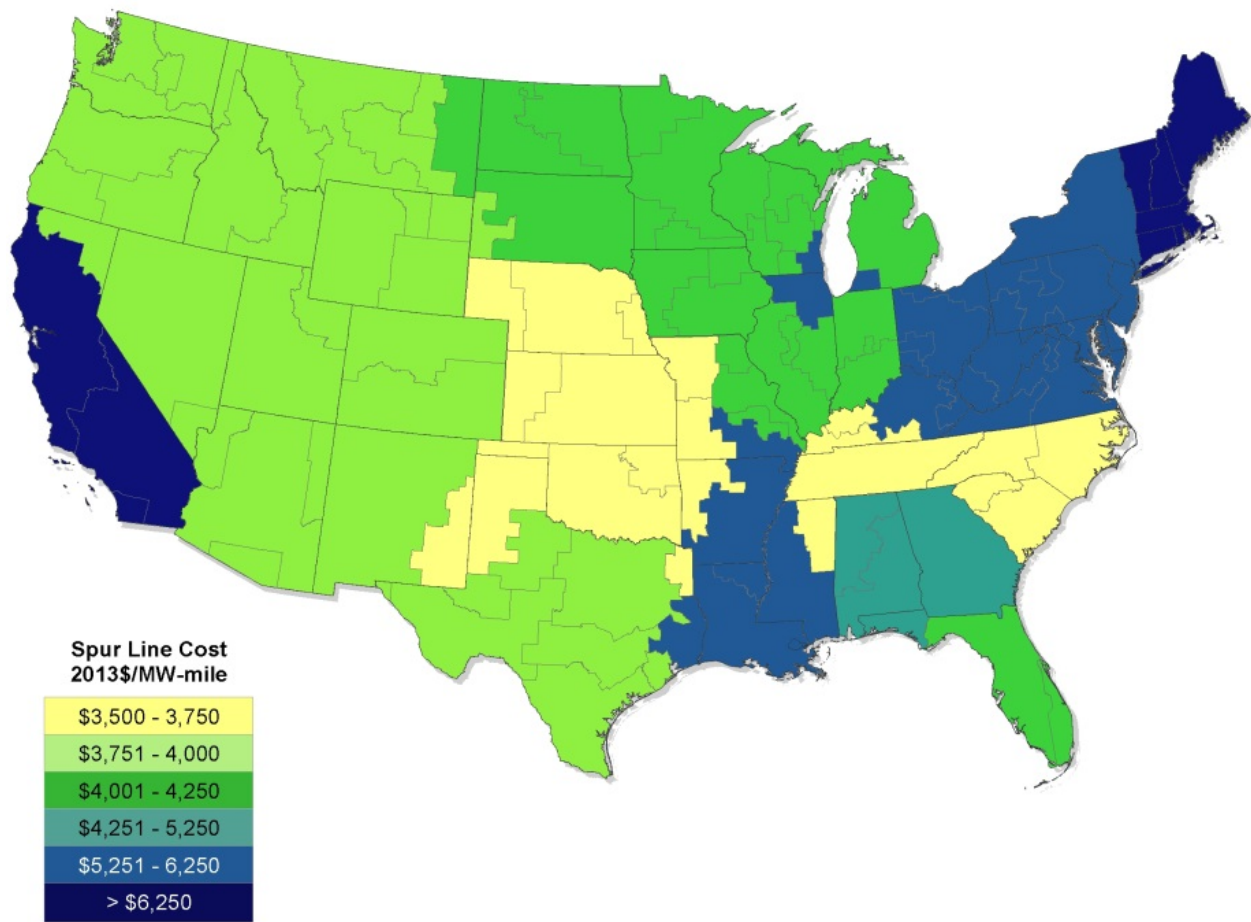


Figure A-8. Spur line regional transmission costs including regional multipliers

Appendix B. Performance Modeling

To characterize performance, the U.S. offshore area was segmented into 7,159 distinct wind power plant layouts of 600 MW each. Analysts developed a new code for Openwind that enables it to automatically process wind resource grid data throughout the entire U.S. offshore technical resource area. This automated process yields wind power plant performance results for each wind project location. These results, including gross annual energy production and wake losses, are fed into the data processing framework and enable the calculation of site-specific leveled cost of energy (LCOE). This appendix describes this process in detail.

B.1 Scripting Performance Modeling

Geographic coordinates for 1,051,800 turbines, each with unique identifiers, from the wind turbine grid were assigned to wind power plant grid cells using scripted routines and stored to a master location reference file for each Universal Transverse Mercator (UTM) zone. These locations are referenced by additional scripts that placed turbines into layouts in Openwind workbooks by UTM zone. The subdivision of turbines by UTM zone is shown in Figure B-1.

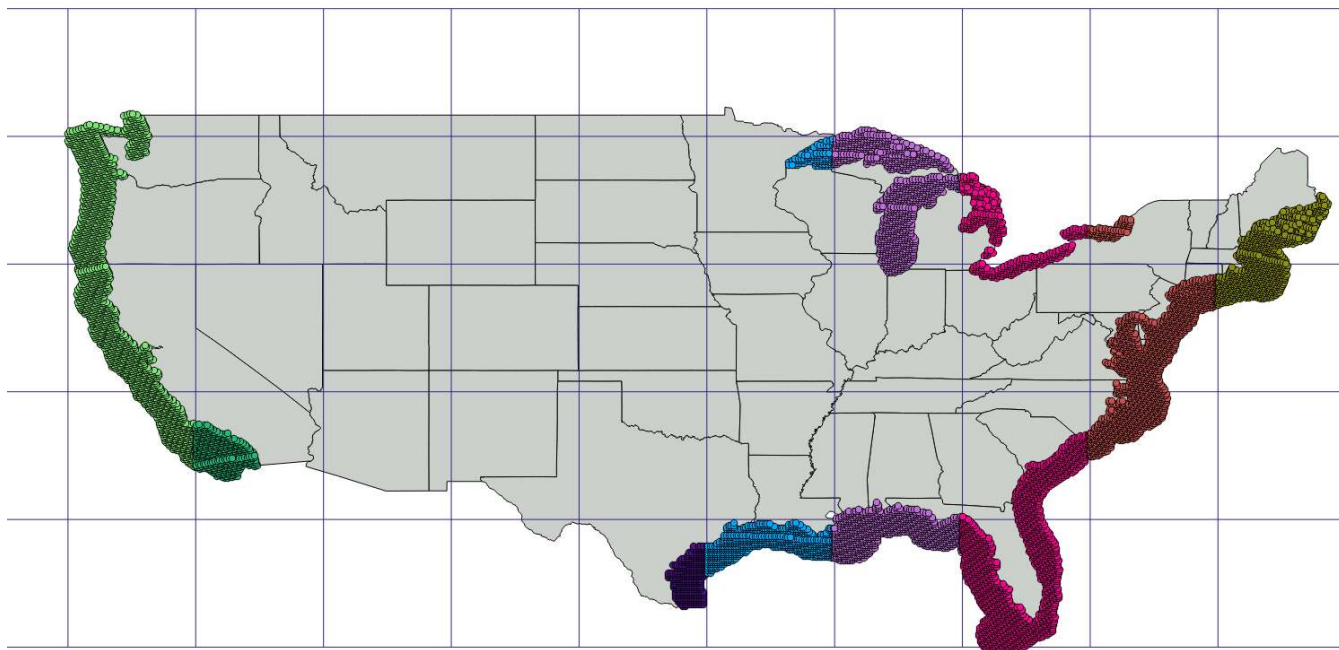


Figure B-1. Wind turbine locations by UTM zone

A command-line version of Openwind (v01.06.00.1482 64 bit) with no graphical interface is used to complete the performance modeling. The command-line version of Openwind uses scripts following a format specified by AWS Truepower to run each workbook with the desired parameters. An Openwind script starts with a wind resource grid and a turbine layout. Each new “replace turbine positions” operation moves the turbine layout to a new location and computes the energy capture. It is not necessary for the initial layout in the workbook to be located within the wind resource grid because the energy capture will never be run for this location.

The initial position shape files are generated for each wind resource grid file in the format `initPos_XXX_YY_ZZ.shp`, in which XXX is longitude, YY is latitude, and ZZ is the UTM zone. This step is not strictly necessary, but it makes the process easier to debug. A single initial position shapefile could be used instead, but this approach allows the user to test the energy capture operation when building the workbook file.

The Openwind turbine position files for each wind power plant are generated directly from the master turbine location files. If an alternate UTM zone is specified, the coordinates are transformed to that zone, and the file is written to the alternate zone's folder. Thus, it is possible for there to be multiple turbine position files for a given wind power plant. Multiple turbine position files for the same location were allowed to run in the model, and then duplicate result files were trimmed out when postprocessing the data.

Workbook files were created manually for each initial position file because Openwind scripts do not include all of the functions required to complete this initial setup. The setup process is also very quick once it has been repeated several times, taking only seconds per workbook.

Results are written to files with names `blkECrpt_XX_YY.txt` and for each wind power plant position. These files are the output of Openwind, but they need to be combined with information from the script file to provide useful information. A separate command joins the list of wind power plants found in the script file with the Openwind output and creates plots of net energy by wind power plant as well as the energy statistics file named `stats_XX_YY.txt` and shape files named `nete_XX_YY.shp`. These result files are then filtered to eliminate duplicate wind power plant results and combined into a single shape file containing the results for all wind power plants in the offshore regions.

B.2 Linear Wake Modeling Parameters

The performance modeling includes the calculation of losses from turbine-to-turbine wake effects within each 600-MW wind power plant. Linear wake models, such as Openwind, have limitations and often deviate significantly from observed losses for large layouts and when stable atmospheric conditions occur; however, they are computationally efficient and enable the analysis of many wind turbines that can be compared among many locations.

Standard linear wake models used across the industry include park, modified park, and eddy viscosity. AWS Truepower includes deep-array versions of each of these wake models. The deep-array models compare wind speed deficits from a pair of internal boundary layers generated at the top and bottom of the turbine rotor to the deficits from the linear wake model. The highest deficit is selected for each turbine and used to represent the wake losses.

For this analysis, the deep-array wake model eddy viscosity option is applied within Openwind Enterprise. The default options result in the model being used for wind speed steps of 1 m/s from 5 to 30 m/s over 72 direction steps. These settings have been found to yield good results for previous analysis when compared to equivalent linear wake models.

Appendix C. Calculation of Location-Specific Costs

C.1 Levelized Cost of Energy

To calculate the levelized cost of energy (LCOE) for each potential offshore wind power project location, NREL analysts ran a series of parameter studies in structural, electrical, and process models to identify how cost items change with respect to key spatial conditions. These cost curves were incorporated into the data processing framework, which aggregates and combines cost and performance functions to generate location-specific LCOE results.

NREL uses LCOE as the central metric for the economic evaluation of wind power plant locations, which can be summarized as the net present value (NPV) of all project expenditures divided by the NPV of energy production. In this assessment, however, NREL approximates the discounted cash flow through the use of annualized values that are representative of lifetime averages.

The LCOE metric excludes policy incentives (e.g., renewable energy credits) and other revenue streams (e.g., capacity payments) that may be available to an offshore wind power project with a specific state or region.⁵⁰ This metric is calculated at the point of interconnection with the existing electricity grid.

There are four major inputs into the LCOE equation. Three parameters—capital expenditures (CapEx), operational expenditures (OpEx), and annual energy production (AEP)—enable the equation to represent system impacts from design changes. The total costs of financing are represented by the fourth major input: a fixed charge rate (FCR). FCR is defined as the amount of revenue per dollar of investment that must be collected annually to pay carrying charges on the investment as well as taxes.

A number of different methodologies have been developed to calculate LCOE. NREL uses a methodology adapted from *A Manual for the Economic Evaluation of Energy Efficiency and Renewable Energy Technologies* (Short et al. 1995) for the U.S. Department of Energy’s *Wind Vision* (DOE 2015).

NREL uses the following equations to calculate site-specific LCOE for each location in the U.S. offshore technical resource area. Table C-1 describes each of the variables.

$$LCOE = \frac{FCR * CAPEX + OPEX}{AEP_{net}}$$
$$FCR = CRF * ProFinFactor$$
$$CRF = \frac{WACC - 1}{1 - \left(\frac{1}{WACC}\right)^t}$$
$$WACC = \frac{(1 + [(1 - DF)(RROE * i - 1)] + [DF(IR * i - 1)(1 - TR)])}{i}$$

⁵⁰ LCOE does, however, account for the value of the Modified Accelerated Cost Recovery System, which allows renewable energy project owners to depreciate CapEx during a 5-year schedule. The Modified Accelerated Cost Recovery System is part of the permanent tax code and included in LCOE because NREL views it as a structural feature of the U.S. market.

$$ProFinFactor = \left(\frac{1 - TR * PVD}{1 - TR} \right)$$

$$PVD = \sum_{y=1}^{M+1} FD_y f_y$$

$$f_y = \frac{1}{d^y}$$

$$d = WACC * i$$

$$CAPEX = ConFinFactor * (OCC * CapRegMult + GCC)$$

$$ConFinFactor = \sum_{y=0}^{C-1} AI_y FC_y$$

$$AI_y = 1 + (1 - TR) * (IDC^{y+0.5} - 1)$$

$$GCC = GF + OnSpurCost$$

$$OnSpurCost = OnDist * OnTransCost * OnRegTransMult$$

$$AEP_{net} = GCF * 8760 * 600 * (1 - AEP_{SysLosses})$$

$$AEP_{SysLosses} = 1 - (1 * (1 - Losses_{Electrical}) * (1 - Losses_{Wake}) * (1 - Losses_{Other}) * Availability)$$

Table C-1. Parameters Required for LCOE Calculation

	Symbol	Name	Definition
Project Finance	<i>t</i>	Economic lifetime (yr)	Length of time for paying off assets (20 yrs)
	<i>DF</i>	Debt fraction	Fraction of capital financed with debt; 1-DF is assumed financed with equity (50%)
	<i>RROE</i>	Rate of return on equity (real)	Rate of return on the share of assets financed with equity (10% real; 13% nominal)
	<i>IR</i>	Interest rate (real)	Interest rate on debt (5.4% real; 8% nominal for all technologies)
	<i>i</i>	Inflation rate	Assumed inflation rate based on historical data (2.5%)
	<i>TR</i>	Tax rate	Combined state and federal tax rate (40%)
	<i>M</i>	Depreciation period (yr)	Number of years in Modified Accelerated Cost Recovery System depreciation schedule (5 yrs)
	<i>FD</i>	Depreciation fraction	Fraction of capital depreciated in each year, 1 to M (20%, 32%, 19.2%, 11.5%, 11.5%, 5.76%)
	<i>CRF</i>	Capital recovery factor	The ratio of a constant annuity to the present value of receiving that annuity for a given length of time (8.89% real; 10.9% nominal). CRF is a function of WACC and <i>t</i> .
	<i>WACC</i>	Weighted average cost of capital (real)	Average expected rate that is paid to finance assets (6.2% real; 8.9% nominal). WACC is a function of <i>DF</i> , <i>RROE</i> , <i>IR</i> , <i>i</i> , and <i>TR</i> .

	Symbol	Name	Definition
	<i>ProFinFactor</i>	<i>Project finance factor</i>	<i>Financial multiplier to account for the taxes and depreciation (1.137). ProFinFactor is a function of TR, WACC, i, M, and FD.</i>
Wind Power Plant Techno-Economic Cost Parameters	OCC	Overnight capital cost (\$)	CapEx, excluding construction period financing; includes on-site electrical equipment and grid connection costs
	<i>CapRegMult</i>	Capital regional multiplier	Capital cost multipliers to account for regional variations that affect plant costs (e.g., labor rates)
	C	Construction duration	Number of years in the construction period (3 yrs)
	FC	Capital fraction	Fraction of capital spent in each year of construction (20%, 40%, 40%)
	IDC	Interest during construction	Interest rate for financing project during construction period (8%)
	OPEX	Operation and maintenance (O&M) expenditures (\$)	Annual expenditures to operate and maintain equipment
	CAPEX	CapEx	<i>Total CapEx to achieve commercial operation up to the land-based substation</i>
	<i>ConFinFactor</i>	<i>Construction finance factor</i>	<i>Portion of CapEx associated with construction period financing (1.064). ConFinFactor is a function of C, FC, and IDC.</i>
Grid Connection Costs	GF	Grid feature	Point of interconnection at the high-voltage transmission network, including the substation, transmission lines, load center, or balancing authority area center. (Default is \$0/kW for the substation and load center and \$14/kW for others; cost adds if upgrades are required.)
	<i>OnDist</i>	Land-based distance	Total distance covered by the land-based transmission spur lines
	<i>OnTransCost</i>	Land-based transmission costs	Base land-based transmission line costs used to price spur lines(\$3,922/MW-mile)
	<i>OnRegTransMult</i>	Land-based regional transmission multiplier	Cost multipliers to account for regional variations that affect land-based transmission line costs (e.g., labor rates, terrain, siting)
	GCC	<i>Grid connection costs</i>	<i>All costs from the land-based substation to the high-voltage transmission network</i>
	<i>OnSpurCost</i>	<i>Land-based spur line costs</i>	<i>Cost for land-based transmission lines from the land-based substation to the grid feature. OnSpurCost is a function of OnDist, OnTransCost, and OnRegTransMult.</i>

	Symbol	Name	Definition
Wind Power Plant Performance Parameters	<i>AEP_{net}</i> (MWh)	<i>Net AEP</i>	<i>Net AEP of all system losses: AEP_{net} is a function of gross capacity factor and AEP_{SysLosses}.</i>
	GCF	Gross capacity factor (%)	Ratio of actual annual output to output at rated capacity for an entire year. Multiplying CF by number of hours in a year (8,760 h) and wind power plant capacity (600 MW) allows analysts to estimate average AEP throughout the technical life of the wind power plant.
	<i>Loss_{Tot}</i>	<i>Total system losses</i>	<i>Aggregated wind power plant losses. Loss_{Tot} is a function of Loss_{Electric}, Loss_{Wake}, and Loss_{Other}.</i>
	<i>Loss_{Electric}</i>	Electrical system losses (%)	Losses in the transmission system (array, substation, export) caused mainly by capacitance within cables and transformers; site-specific estimate using curves derived from the electrical parameter study
	<i>Loss_{Wake}</i>	Wake losses (%)	Lost production that occurs as a result of wake interaction among turbines within the project; site-specific estimate using Openwind
	<i>Loss_{Other}</i>	Other system losses (%)	Loss categories that are unlikely to change with location for offshore wind power projects; includes losses related to temperature, icing, hysteresis, and lightning (2%)
	Availability	Technical availability (%)	Average proportion of time that the wind project is available to generate power at full capacity in a single year; site-specific estimate using curves derived from O&M parameter study

Note: Entries in italic are intermediate calculations required to compute LCOE; nonitalic entries are either input assumptions or derived from geographic information system data layers. Assumptions not defined in the table are described in subsequent sections of this appendix.

To develop relationships among wind power plant cost and performance values and spatial parameters, NREL ran a series of parameter studies. Figure 5 summarizes the LCOE framework that underpins the economic calculations in this report.

This assessment holds the financial variables constant (nominal discount rate = 8.9%), a rate that NREL views as representative of an average for power project financing in the United States. Table C-2 summarizes the financial input assumptions as well as the calculated FCR.

Table C-2. Electric Generation Plant Financing Assumptions

Evaluation Period	20 yrs
Inflation Rate	2.50%
Interest Rate—Nominal	8%
Rate of Return on Equity—Nominal	13%
Debt Fraction	50%
Combined State and Federal Tax	40%
Discount Rate—Nominal (Real)	8.9% (6.2%)
Modified Accelerated Cost-Recovery System (Nonhydropower Renewables)	5 yrs
Calculated FCR	10.51%

Market data suggests that offshore wind power plant financing may be better represented by a weighted average cost of capital of 10.5% for the first projects in the United States because of the uncertainties associated with opening a new market (Tegen et al. 2011). This assessment assumes, however, that several commercial-scale projects using fixed-bottom technology will be installed before commercial-scale floating offshore wind power projects.

This assessment aims to identify the relative differences among project sites resulting from spatial parameters. Note that the constant financial assumption may not capture the full extent of this variability; different sites may have different risk profiles, which may trigger different return requirements.

C.2 Variable Costs

Variable costs refer to categories of expenditures that have distinct relationships with spatial parameters. For example, installation costs are expected to vary with logistical distances (e.g., distance from port to site), water depth, and prevailing metocean conditions. This section describes parameter studies that NREL conducted to describe how each of the four major variable cost categories relate to spatial parameters.

C.2.1 Substructure and Foundation Parameter Study

Fixed-Bottom Substructures

Environmental Parameters

Table C-3 shows the range of main environmental parameters that were considered. For simplicity, soil characteristics were fixed throughout the various cases at an average stiffness soil profile (friction angles ~35 degrees). Soil stratigraphy was used to approximate the needed pile length based on axial pile capacity, but no further effect on the structure dynamics was considered other than a degradation in system eigenfrequency of approximately 10%.

For the reference turbines used in this study (see Appendix A), the target first natural frequencies, based on a soft-stiff design approach (Damiani and Song 2013) represent the modal performance requested for the various system layouts. The target frequency values reported in

this appendix were the minimum allowed values requested to the optimizer, with associated acceptance ranges equal to 5% of those values.

Two characteristic load cases were investigated. One, similar to the International Electrotechnical Commission (IEC) DLC 1.6 (IEC [2009]), assumes maximum turbine rotor thrust and maximum wave load aligned along the base of the structure. The other, similar to the IEC DLC 6.1 (IEC [2009]), assumes the machine idling during an extreme (50-yr) wind and wave event. The loads from the rotor nacelle assembly (RNA) were precalculated based on experience with other projects.

Because of the simplifications in the physics of the used software programs, and because of the limited number of load cases considered, an additional safety margin was provided by the employed drag (*cd*) and added mass (*cm*) coefficients, the choice of a worst-case loading scenario, and additional safety factors. Based on verification runs with other codes (Damiani [2016]), the jacket substructure *cd* and *cm* were doubled in the case of the jacket; in the same case for the tower, the wind *cd* was set to 2 to account for transition piece drag. Further, wave loads calculated on the main jacket legs were multiplied by a factor of 4 to account for hydrodynamics effects on secondary members of the substructure otherwise ignored.

Both TowerSE and JacketSE were run in stand-alone mode to obtain minimum overall mass configurations of support structures based on monopiles and jacket substructures, respectively, including the mass of the tower, four-legged jacket, transition piece, and pile(s).

Optimization Parameters

The optimization made use of Sparse NOnlinear OPTimizer, a gradient-based, sparse, sequential, quadratic programming method as implemented in Python (Gill, Murray, and Saunders [2005]). The final accuracy in the optimization and the feasibility tolerance were set at 10^{-3} . For each support structure type, the design variables and constraints are listed in Table C-3 and Table C-4; constraint functions were based on structural integrity and manufacturability criteria (see also Damiani [2016]).

Table C-3. Variables and Constraints for the Monopile Substructure

Description	Number of Variables/Constraints
Tower and Monopile Outer Diameters	4
Tower, Transition Piece, and Monopile Wall Thicknesses	5
Utilization Against Shell and Global Buckling	40
Utilization Against Strength	40
Eigenfrequency Bounds	2
Tower Taper Ratio (Manufacturability)	1
Diameter-to-Thickness Ratio (Manufacturability)	6
Grout Thickness	2

Table C-4. Variables and Constraints for the Jacket Substructure

Description	Number of Variables/Constraints
Tower Outer Diameters and DTRs	4
Tower Waist Height	1
Transition Piece Girder Outer Diameters and Wall Thicknesses	2
Transition Piece Deck Width	1
Jacket Batter	1
Jacket Leg, X-Brace, Mud Brace, Outer Diameters, and Wall Thicknesses	6
Pile Outer Diameter, t, Length	3
Tower Taper Ratio (Manufacturability)	1
Tower Utilization Against Shell and Global Buckling	60
Tower Utilization Against Strength	30
Tower and Member DTRs (Manufacturability)	5
Batter Range (Manufacturability)	2
Maximum Footprint	1
Minimum Jacket Brace Angle	1
Jacket Member Additional Structural Criteria	10
Jacket Member Utilization	147–203 (depending on the number of bays)
Jacket Joint Utilization	56–80 (depending on the number of bays)
Pile Length (Manufacturability and Axial Capacity)	2
Eigenfrequency Range	2
Consistency Among Members	2

Wind Turbine Properties

The turbines described in this appendix are generic and based on averaging known data sets from various turbines used within NREL studies.

Generic Turbine (3 MW)

This section presents an overview of the 3-MW generic wind turbine used in the sizing exercises. Table C-5 outlines the properties of the RNA. For the floating substructures, the towers were fixed after being obtained via independent optimizations, whereas for fixed-bottom configurations they were optimized with the rest of the support structure components. Table C-6 outlines the properties of the tower for the 3-MW floating turbine.

Table C-5. RNA Properties for the 3-MW Wind Turbine

Description	Value
Mass (kg) (Fixed System)	175,000
Mass (kg) (Floating System)	125,000
Rotor Diameter (m)	101
CGZ (m) (Offset from Tower-Top Center)	1.5
CGX (m) (Offset from Tower-Top Center)	4.1
ThX (m) (Thrust Point Offset from Tower-Top Center)	-3.78
ThZ (m) (Thrust Point Offset from Tower-Top Center)	1.5
Ixx, Iyy, Izz (Second Moment of Inertia) (kg m ²)	1.81e7, 1.06e7, 1.1e7
Hub Height (m)	75

Table C-6. Floating-System Tower Properties for the 3-MW Wind Turbine

Description	Value
Tower Shell Mass (kg)	127,877
Length (m)	60.5
Top Outer Diameter (m)	2.5
Base Outer Diameter	4.89

Table C-7 shows the assumed RNA loads for this turbine. In designing the fixed-bottom support structures, the target eigenfrequency was set at 0.35 Hz, within the expected soft-stiff range.

Table C-7. Assumed Loads for the 3-MW Wind Turbine

Description	Max. Thrust Load Case	Parked Load Case
Nominal Gust Speed at Hub Height (m/s)	20	55
RNA Force Loads (Excluding Weight) (N)	7.26e5, 4.19e4, 6.7e5	1.15e5, -3.31e4, 6.01e5
RNA Moment Loads (Excluding Weight) (Nm)	2e6, -5.31e6, 1.11e6	-2.04e6, -5.39e6, 1.63e4

Generic Turbine (6 MW)

This section presents an overview of the 6-MW generic wind turbine used in the sizing exercises. Table C-8 outlines the properties of the RNA. For the floating substructures, the towers were fixed after being obtained via independent optimizations, whereas for fixed-bottom configurations they were optimized with the rest of the support structure components. Table C-9 outlines the properties of the tower for the 6-MW floating turbine.

Table C-8. RNA Properties for the 6-MW Wind Turbine

Description	Value
Mass (kg)	365,500
Rotor Diameter (m)	155
CGZ (m) (Offset from Tower-Top Center)	3.04
CGX (m) (Offset from Tower-Top Center)	-4.1
ThX (m) (Thrust Point Offset from Tower-Top Center)	-7.76
ThZ (m) (Thrust Point Offset from Tower-Top Center)	3.5
Ixx, Iyy, Izz (Second Moment of Inertia) (kg m ²)	7.92e7, 4.26e7, 4.04e7
Hub Height (m)	97

Table C-9. Floating System Tower Properties for the 6-MW Wind Turbine

Description	Value
Tower Shell Mass (kg)	366,952
Length (m)	80.5
Top Outer Diameter (m)	3.51
Base Outer Diameter	6.00

Table C-10 shows the assumed RNA loads for this turbine. In designing the fixed-bottom support structures, the target eigenfrequency was set at 0.28 Hz, within the expected soft-stiff range.

Table C-10. Assumed Loads for the 6-MW Wind Turbine

Description	Max. Thrust Load Case	Parked Load Case
Nominal Gust Speed at Hub Height (m/s)	20	55
RNA Force Loads (Excluding Weight) (N)	1.94e6, -2.12e5, -1.46e5	1.8e5, -4.21e4, 1.28e5
RNA Moment Loads (Excluding Weight) (Nm)	5.35e6, 1.56e7, -1.8e6	-1.42e4, 1.11e7, -1.39e5

Generic Turbine (10 MW)

This section presents an overview of the 10-MW generic wind turbine used in the sizing exercises. Table C-11 outlines the properties of the RNA. For the floating substructures, the towers were fixed after being obtained via independent optimizations, whereas for fixed-bottom configurations they were optimized with the rest of the support structure components. Table C-12 outlines the properties of the tower for the 10-MW floating turbine.

Table C-11. RNA Properties for the 10-MW Wind Turbine

Description	Value
Mass (kg)	677,000
Rotor Diameter (m)	194
CGZ (m) (Offset from Tower-Top Center)	2.75
CGX (m) (Offset from Tower-Top Center)	-0.87
ThX (m) (Thrust Point Offset from Tower-Top Center)	-7.07
ThZ (m) (Thrust Point Offset from Tower-Top Center)	3.37
Ixx, Iyy, Izz (Second Moment of Inertia) (kg m ²)	1.65e8, 1.01e8, 1e8
Hub Height (m)	119

Table C-12. Floating System Tower Properties for the 10-MW Wind Turbine

Description	Value
Tower Shell Mass (kg)	698,235
Length (m)	102.63
Top Outer Diameter (m)	1.05
Base Outer Diameter	7.72

Table C-13 shows the assumed RNA loads for this turbine. In designing the fixed-bottom support structures, the target eigenfrequency was set at 0.25 Hz, within the expected soft-stiff range.

Table C-13. Assumed Loads for the 10-MW Wind Turbine

Description	Max. Thrust Load Case	Parked Load Case
Nominal Gust Speed at Hub Height (m/s)	20	55
RNA Force Loads (Excluding Weight) (N)	3.23e6,0,0	2.29e6, 1.63e6, 2.32e6
RNA Moment Loads (Excluding Weight) (Nm)	9.95e6, 5.07e6, 0	8.77e5, -1.35e7, 1.58e7

TowerSE and JacketSE

TowerSE and JacketSE are preliminary sizing tools for support structures including towers, monopiles, and jacket substructures. These tools are based on simplified physics and load case analyses and do not claim to be sufficient to arrive at final design details, but they offer a rapid and versatile way to analyze the multiple effects of design choices and environmental conditions.

JacketSE and TowerSE aid the designer in the search for an optimal preliminary configuration of the substructure and tower and for given metocean conditions, turbine loading, modal

performance targets, and design standard criteria. The two software programs are similar in framework and share some load-calculation routines. This appendix shows a flowchart of the framework (Figure C-3). JacketSE includes the dimensioning of the tower component and uses the same structural code checks as TowerSE. The main difference lies in the treatment of the substructure, which in TowerSE is a continuation of the tower to the seabed (the pile) with the addition of a tubular transition piece to allow for the connection of the main pile to the tower. JacketSE solves for a multimember substructure (either three- or four-legged lattice) with a more complicated transition piece at the top (see also Figure C-1 and Figure C-2 for diagrams showing nomenclature and geometry assumptions and associated simplifications).

These tools can size outer diameters and wall thicknesses for piles, legs, braces, and tower; other design variables that can be optimized are batter angle, pile embedment, and tower taper height. The design parameters (fixed inputs to the tools) include water depth, deck and hub height, design wind speed, design wave height and period, and soil characteristics (stratigraphy of undrained shear strength, friction angles, and specific weight). Loads from the RNA can be input to the model either from other Wind-Plant Integrated System Design & Engineering Model (WISDEM) modules or directly from the user. The user must also provide acceptable ranges for the design variables—for example, maximum tower diameter, minimum and maximum diameter-to-thickness ratios for the various members, and maximum allowed footprint at the seabed.

The common software framework primarily consists of the following submodules: geometry definition, load calculation, soil-pile interaction, finite-element, and structural code checks. A number of simplifications have been incorporated to allow for rapid analyses of multiple configurations on a personal computer. As such, complex hydrodynamics and associated variables (e.g., tidal range, marine growth, and member-to-member hydrodynamic interaction) are ignored, and fatigue assessments are not carried out by default. Although these aspects can very well drive the design of certain subcomponents and of the overall structure, it is believed that the main structural and mass characteristics should still be captured by the simplified models for the sake of preliminary design assessments and trade-off studies and with a level of accuracy limited to those goals. More details on the codes can be found at <https://github.com/WISDEM> and Damiani (2016).

Within WISDEM, these tools allow for the full gamut of component investigations to arrive at a minimum LCOE wind turbine and power plant layout. For example, together with a turbine rotor and blade model, JacketSE can produce a design that meets tower/substructure clearance criteria while also meeting mass or cost targets. In this study, the tools were used in stand-alone mode, wherein the preliminary design realizations for substructures, foundations, and towers were based on minimizing the overall structural mass.

The definition of the various subcomponents and the approximate locations of the loads assumed in TowerSE and JacketSE are given in Figure C-1. The transition piece is simplified in both cases via equivalent beam finite elements with properties set to match the original component as shown in Figure C-2. In JacketSE, a lumped mass is added near the deck level to account for the deck flooring and appurtenances (e.g., secondary steel, cranes, electronic cabinetry, and so on).

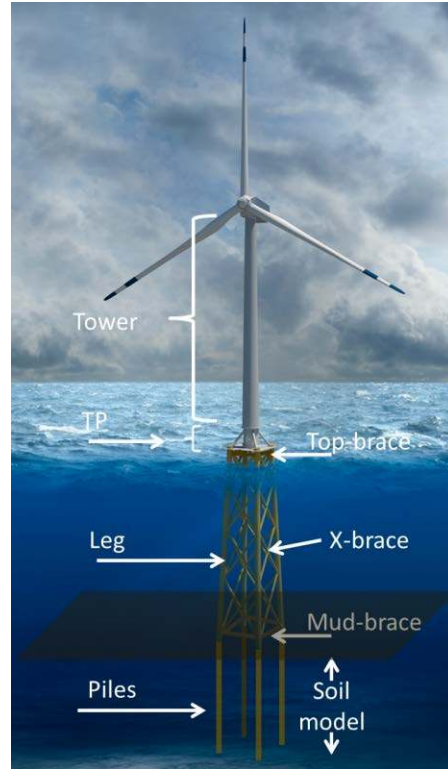
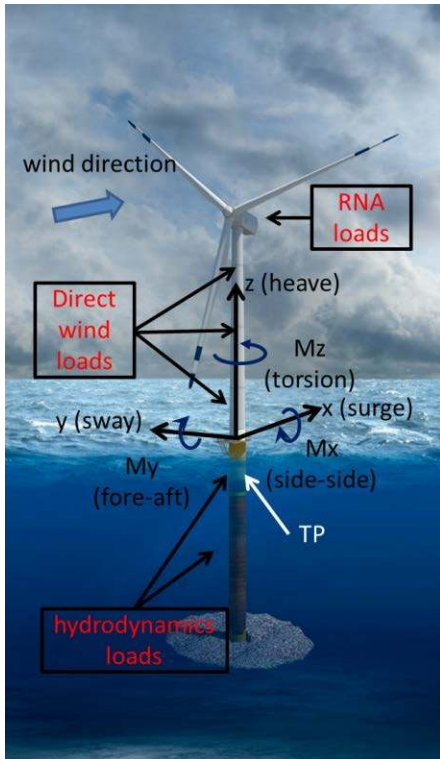


Figure C-1. Reference system, load locations, and definitions of subcomponents in TowerSE and JacketSE. A monopile substructure (left) and a jacket substructure (right) are shown.
Images modified from illustrations by Josh Bauer, NREL

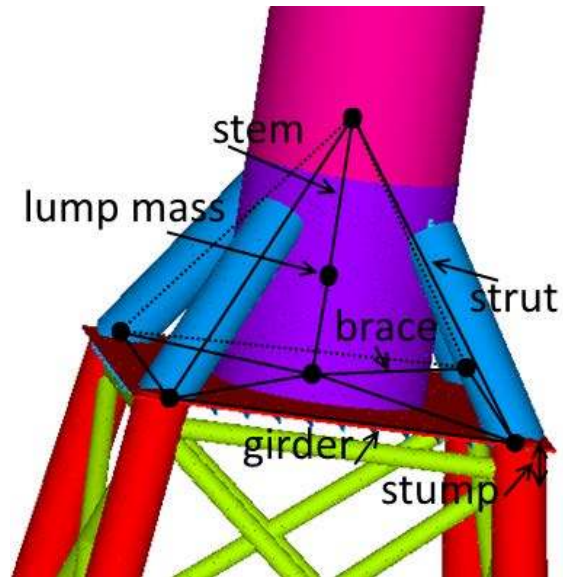
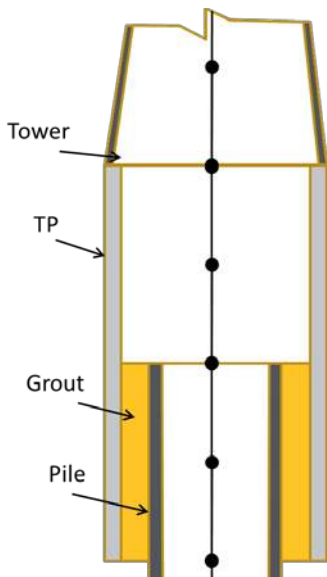


Figure C-2. Transition piece via beam-element simplification for the monopile (left) and the jacket (right) substructure

The optimizer seeks a minimum for the objective function (overall mass in this study) within the bounds, input by the user, for the various design variables. Initial guesses based on engineering judgment and previous experience help reach a global minimum. The main flowchart of the sizing tools is shown in Figure C-3. Inputs from the user are processed to create a first layout of the tower monopile or tower jacket. Next, a finite-element model is created based on the level of resolution requested by the user. The models use beam finite elements, with aerohydrodynamic loads applied at the end nodes, where the structural checks are also performed. Therefore, the user should ensure convergence of the results by changing resolution. The finite-element model calculates the first two eigenmodes and eigenfrequencies; a load module applies the RNA loads, wind drag loads, and hydrodynamic loads to the structure for the design load cases identified by the user. A utilization-ratio (0:1) calculation module then calculates the level of material utilization of the various members based on API (2014) Germanischer Lloyd (2005; 2012) and the European Committee for Standardisation (1993). Based on the assigned criteria in terms of modal performance and a maximum utilization less than one, the optimizer then drives the values of the design variables using a gradient-based approach. The output is a detailed schedule of geometric parameters and masses for the various subcomponents (e.g., legs, x-braces, and tower segments).

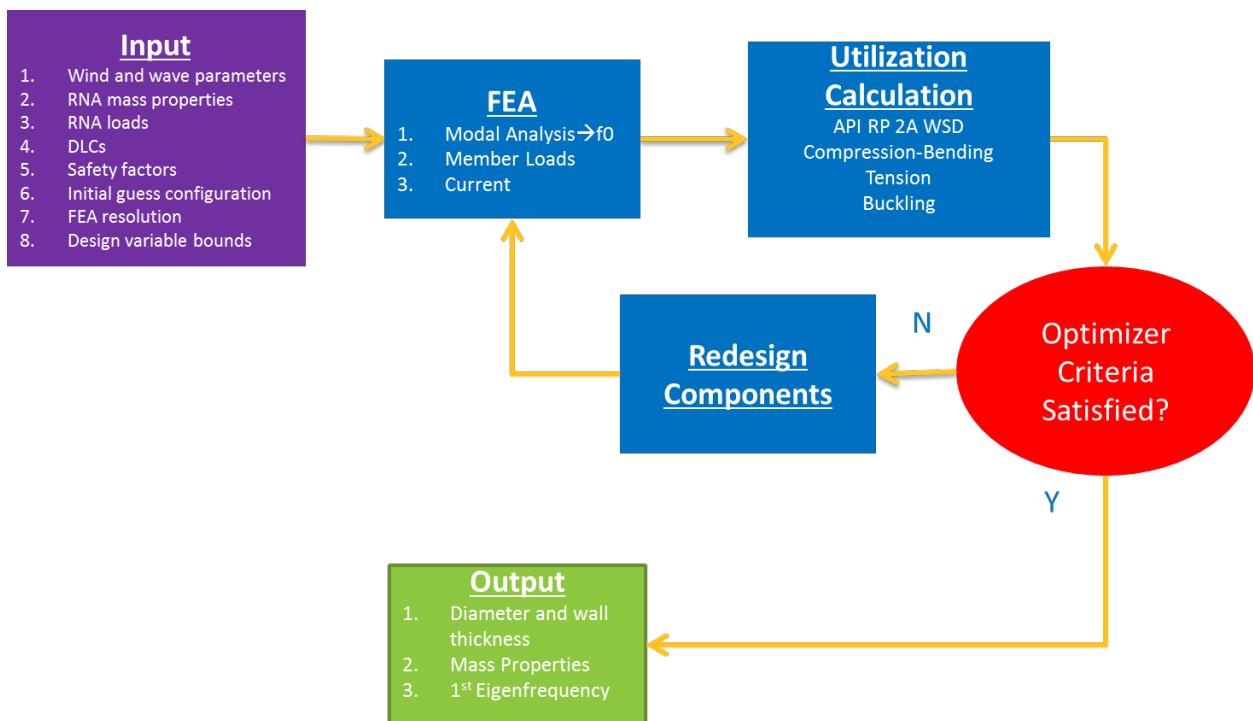


Figure C-3. Basic flowchart for the optimization using either TowerSE or JacketSE

Floater Sizing Tool

To clearly understand the system cost of floating offshore wind power projects, a major piece within the complex puzzle is the cost of the substructure. The substructure, or the floating platform, includes the main structural members (e.g., columns, stiffeners, and cross braces), the secondary steel (e.g., deck, boat landing, and anodes), and the mooring system (e.g., fairleads, lines, and anchors). Accurately estimating the cost of floating substructures requires a sizing tool

that can generate platform configurations for various turbine designs under different metocean conditions. The sizing tools, at minimum, yield weights and dimensions for each of the major components to which cost multipliers can be applied.

Floater Sizing Tool

The Floater Sizing Tool for offshore wind turbine development is based on oil and gas technology. The general process for using the Floater Sizing Tool to size a floating turbine is outlined in Figure C-4. For a platform type (semisubmersible, spar, or tension leg platform), given a set of inputs, the mean loads and weight are calculated. These calculations are used to evaluate the natural periods and stability. The outputs are then checked against established response criteria for stability, natural periods, heel, and offset.

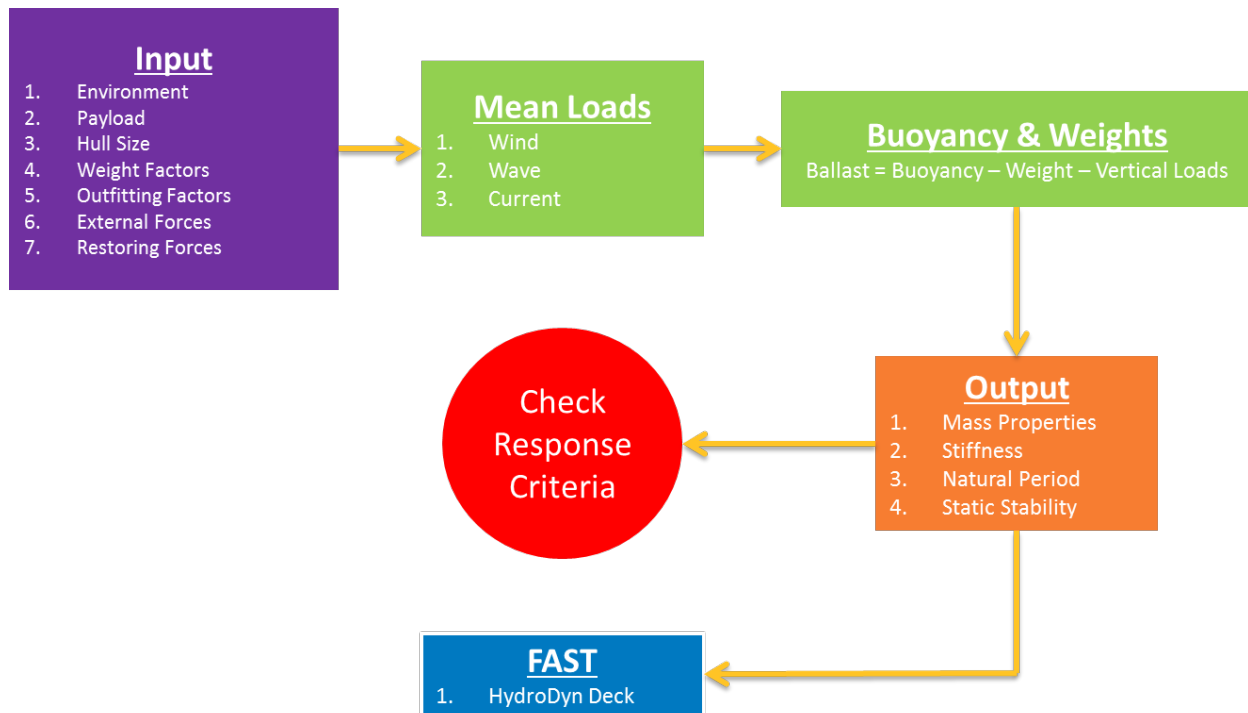


Figure C-2. Outline of NREL’s Floater Sizing Tool

Once the performance criteria are met, the estimated cost of the platform (material and fabrication cost) is estimated using “dollars-per-ton” numbers traditionally used in the oil and gas industry. Although these numbers are based on one-off designs and do not reflect mass production required by the wind industry, they are the best estimates given the state of the fabrication yards in the United States, which are not set up for mass production. The cost estimate also includes procurement of the mooring system (e.g., fairleads, mooring lines, and anchors). Note that the cost estimate output from the Floater Sizing Tool excludes wind turbine procurement (e.g., rotor, nacelle, and tower), dynamic power cable procurement, and system installation.

Spar Sizing Tool

The spar sizing tool, a subset of the Floater Sizing Tool, currently assumes that the spar has a single compartment, single wall, and ring-stiffened column, based on API Bulletin 2U calculations. The single column may consist of multiple sections with a combination of constant-diameter sections and tapered sections with varying diameters. Given the section shell thickness as input and loads, the unity check per API Bulletin 2U is satisfied manually by varying the shell thickness. Shell thickness is not an output as a result of loads but rather an input in an iterative process to comply with API Bulletin 2U. Note that the shell thickness may be driven by fatigue or conditions other than the extreme event, such as boat impact. These detailed analyses are not part of the sizing tool.

The restoring force to counter the environmental and gravitational forces is provided by three mooring lines. These lines have selectable options for chain, wire rope, or fiber rope. Currently, the model supports single, nonsegmented mooring lines (multisegmented lines, bridle connections, and clump weights are not supported). The tower is not sized in the tool. The weight for the RNA and tower are provided by the turbine manufacturer and given as an input to the tool.

The general schematic of the spar sizing tool is illustrated in Figure C-5. The main input parameters are highlighted in purple. Calculated parameters from the main input parameters (thrust and water ballast) that are important to the system response are highlighted in orange.

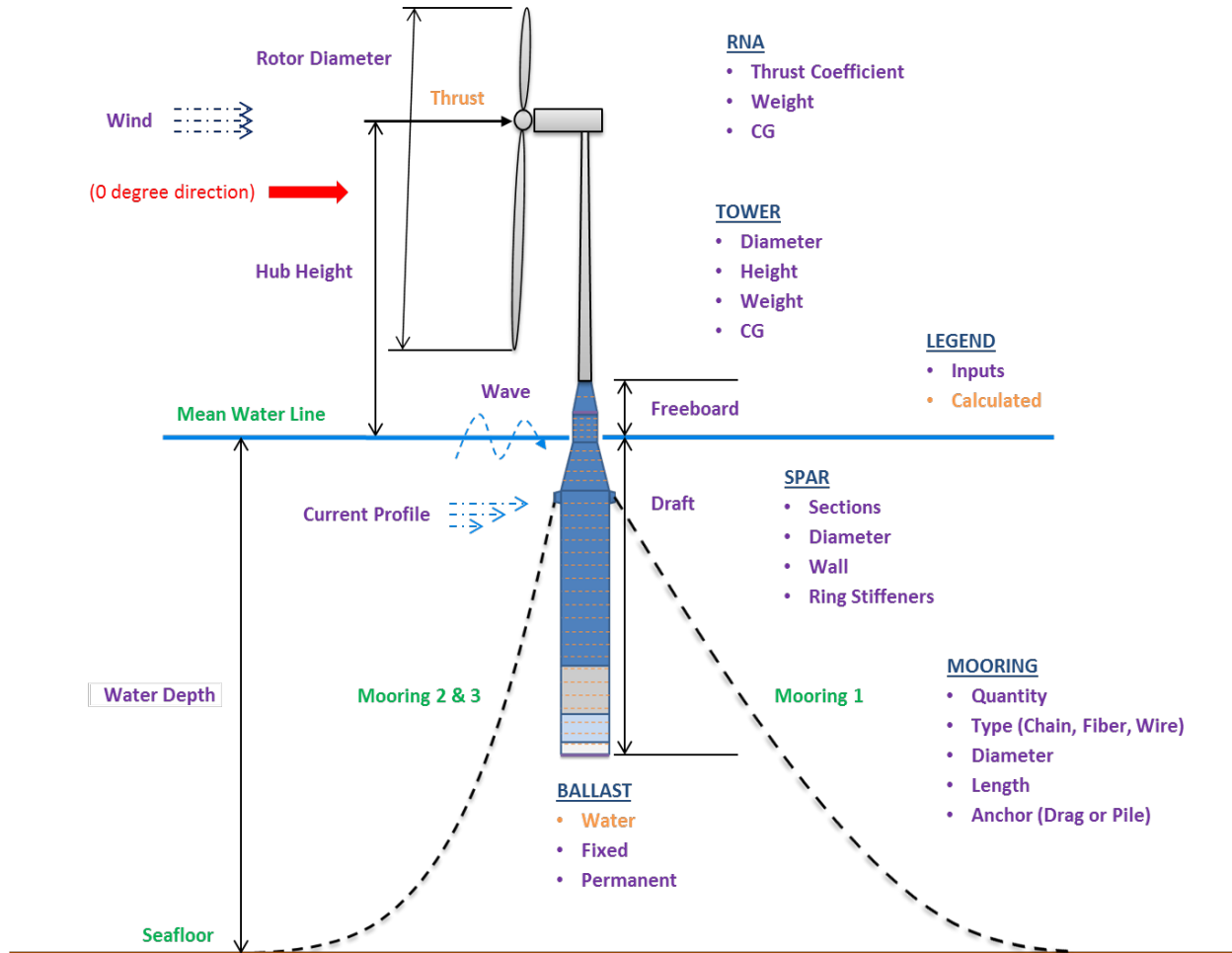


Figure C-3. Spar sizing tool schematic

Semisubmersible Sizing Tool

The semisubmersible is a more complex structure compared to the spar. It typically has multiple columns, cross braces, pontoons, and heave plates. Each of these members needs to be designed per design codes. The columns are typically of the same makeup as the spar, except they are larger and of constant diameter sections with ring stiffeners conforming to the API Bulletin 2U calculations (stability design of cylindrical shells). Although the columns are designed, the other components are scaled to proprietary WindFloat design from Principle Power, Inc., and they are yet to be designed to code. As such, the sizing worksheet has not been implemented for the semisubmersible and will be considered in the future given the time and budget to implement them. The cost estimates are based on the same dollar-per-ton assumptions used for the spar. The mooring lines are similar to the spar, applying three lines instead of four as used in WindFloat with similar options.

The general schematic of the semisubmersible sizing tool is illustrated in Figure C-6. The main input parameters are highlighted in purple. Calculated parameters from the main input parameters (thrust and water ballast) important to the system response are highlighted in orange.

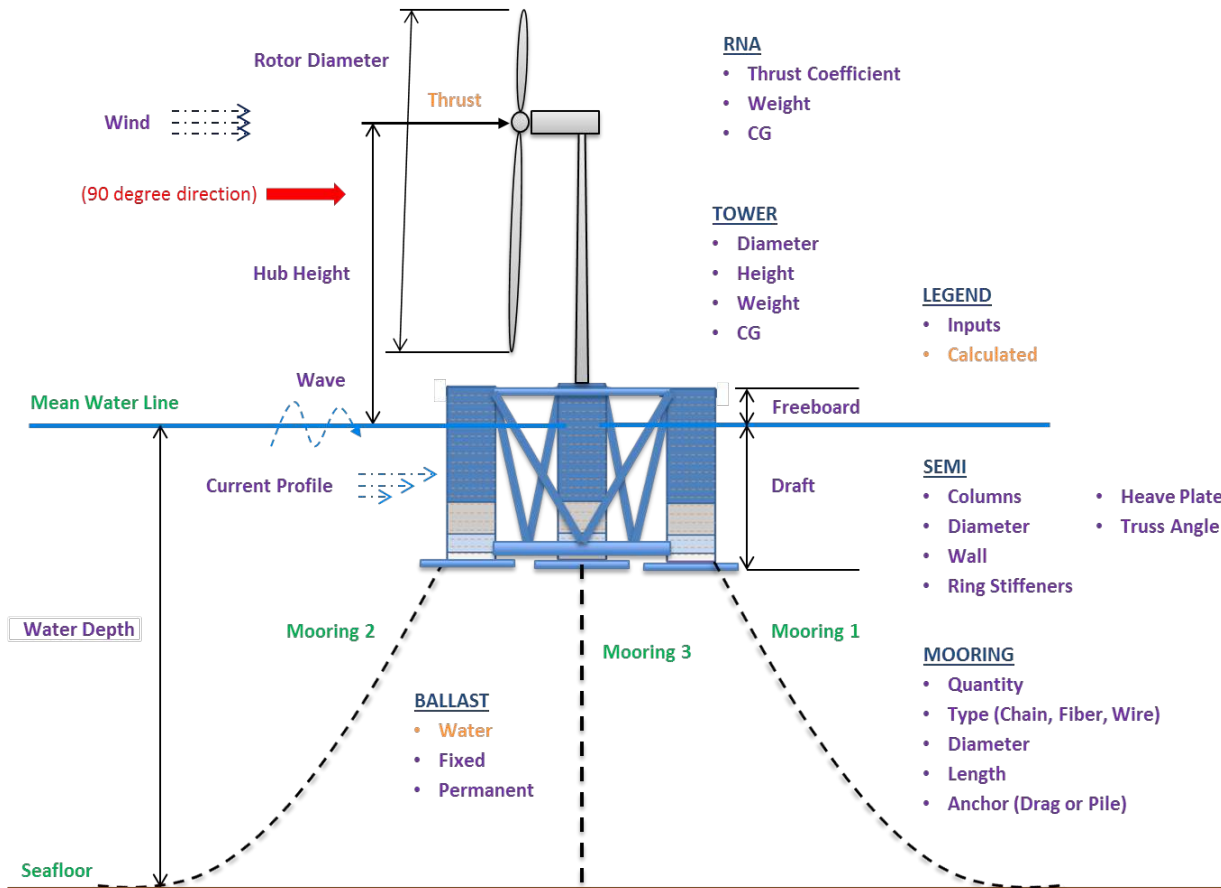


Figure C-6. Semisubmersible sizing tool schematic

C.2.2 Electrical Infrastructure Parameter Study

Balance of Systems Optimization

In general, the balance-of-systems (BOS) costs for offshore wind power plants include site preparations, foundations, control/electrical hardware, an electric collection system within the wind power plant, interconnection to the land-based electric power grid, substation, and plant control and monitoring equipment. BOS costs also include resource assessment, project management and administration, permits, insurance, engineering services, cranes, future decommissioning, and so on. In addition, an infrastructure to support the offshore industry is required (see Figure C-7). Such support infrastructure includes a fleet of vessels for foundation and turbine installation and submarine cable laying, port and harbor upgrades, land-based O&M facilities, decommissioning, and so on. (Figure C-7 shows BOS components for a high-voltage direct-current-[HVDC]-interconnected wind power plant). The design optimization of an offshore wind power plant is necessary to achieve a trade-off between turbine performance losses and wind power plant layout cost savings. A number of key factors need to be considered when determining an offshore wind power plant's layout, such as distance to shore, water depths, seabed geology, number and types of wind turbines, construction and maintenance operations, reliability, and electrical loss minimization; however, the most crucial factor that determines a wind power plant's size for any given capacity is the spacing among the turbines. If distance between individual wind turbines is too close, there is a significant risk of a reduction in the

overall wind power plant's performance as a result of wake effects. On the other hand, increasing the distance between individual wind turbines will increase the cost of a project because of increased infrastructure costs. In addition to turbine spacing, future maintenance-related operations must be considered when deciding on the final layout. For example, locating a substation platform outside of a wind power plant's perimeter is preferable to embedding a platform in the middle of an array. Even with additional cabling needed for an outside location, there is a reduced vessel access risk and better maintenance facilitation throughout the lifetime of the wind power plant. Such platform sitings have been implemented in both Horns Rev 1 and Horns Rev 2 offshore wind power plants (Figure C-8 and Figure C-9). In some cases, the embedded substation platform location is preferred, as shown in Figure C-10 for the proposed Cape Wind project.

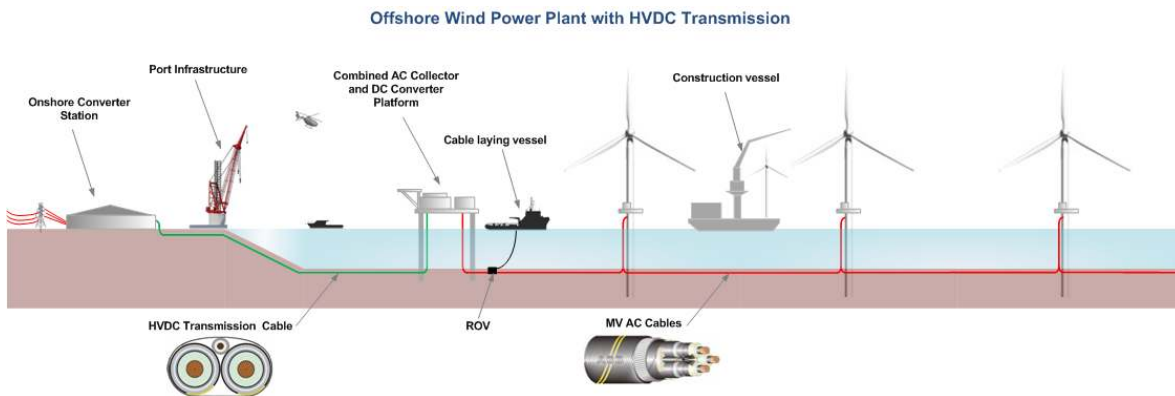


Figure C-7. Wind power plant BOS components (HVDC transmission example)

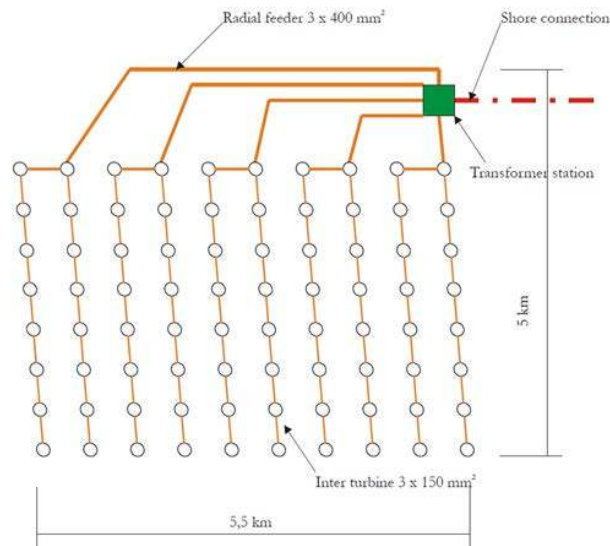


Figure C-8. Layout of the Horns Rev 1 wind power plant. Image from Schachner (2004)

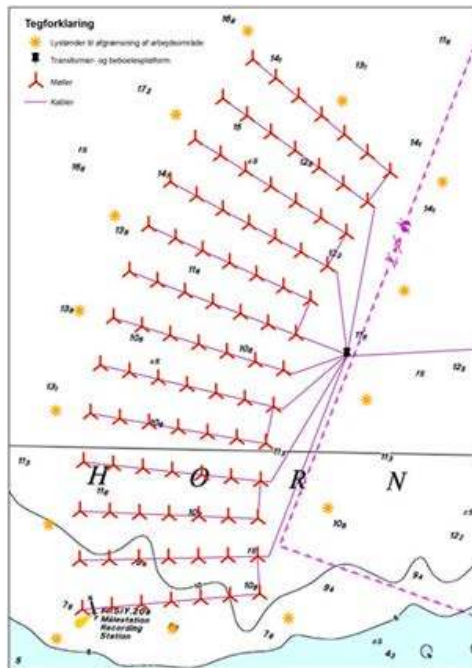


Figure C-9. Layout of the Horns Rev 2 wind power plant. Image from DONG Energy

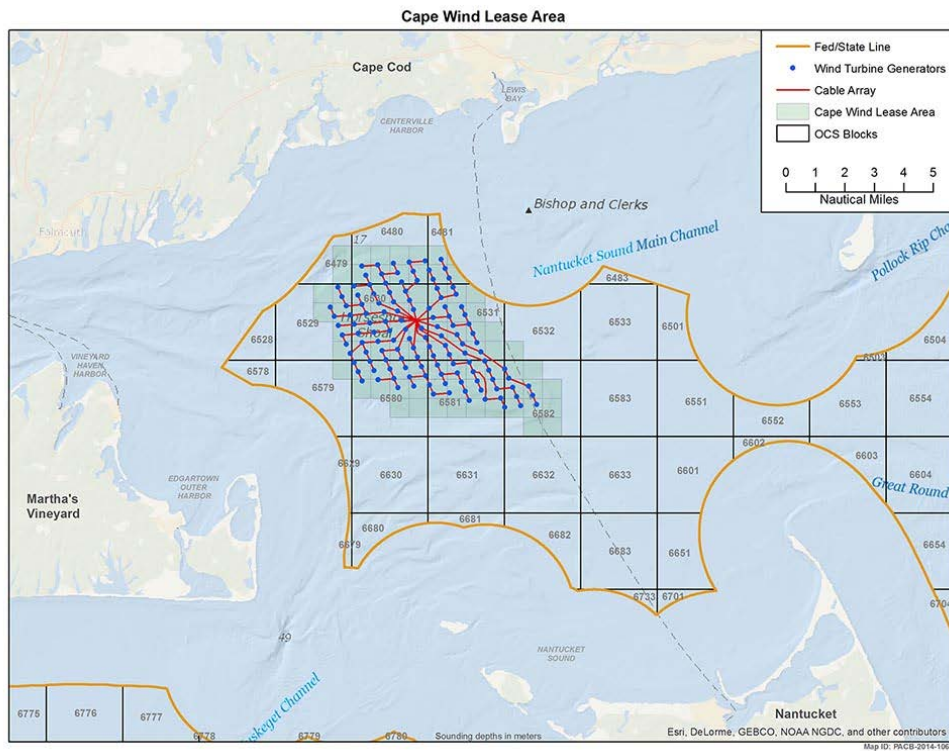


Figure C-10. Layout of the proposed Cape Wind offshore wind power plant. Illustration from www.boem.gov

The engineering of the offshore wind power plant is also heavily affected by a site's depth and distance from the shore. This includes the cost of foundations, wind power plant power collection system, power transmission to the shore, the construction and installation process, and O&M operations. Another important factor determining the cost of the collector system and the cost of foundations is the type and size of the individual wind turbines used in the project.

Determining the optimum electrical configuration and layout of an offshore wind power plant involves many trade-offs. There is a need for validated design tools to find these balances and optimize the design of offshore wind power plants to minimize BOS capital investments and cost of energy and maximize system reliability.

Collector Systems for Offshore Wind Plant

Most offshore wind power plants installed during the past 10–15 years in Europe have been of a relatively small or medium capacity and with a simple electrical interconnect structure following the existing practices applied to land-based wind power. During the last several years, there has been a significant increase in power capacity of offshore wind power plants, and this trend is going to continue. These increasing capacities will have a significant impact on future offshore wind power plant electrical system designs because overall performance, efficiency, and reliability are largely affected by the electrical system architecture and transmission methods for offshore installations. The design of the collector system is of special importance because its layout will determine the cost of the offshore electrical network within the wind power plant and thereby impact reliability. Some examples of possible collector system layouts are shown in Figure C-11. The most simple radial design is shown in Figure C-12 (a), wherein a number of wind turbines in the same radial string are connected to an AC collector bus. This design is relatively inexpensive because of shorter cable lengths, but it has poor reliability because cable or switchgear failures in one wind turbine will stop the operation of all downstream turbines in the same string.

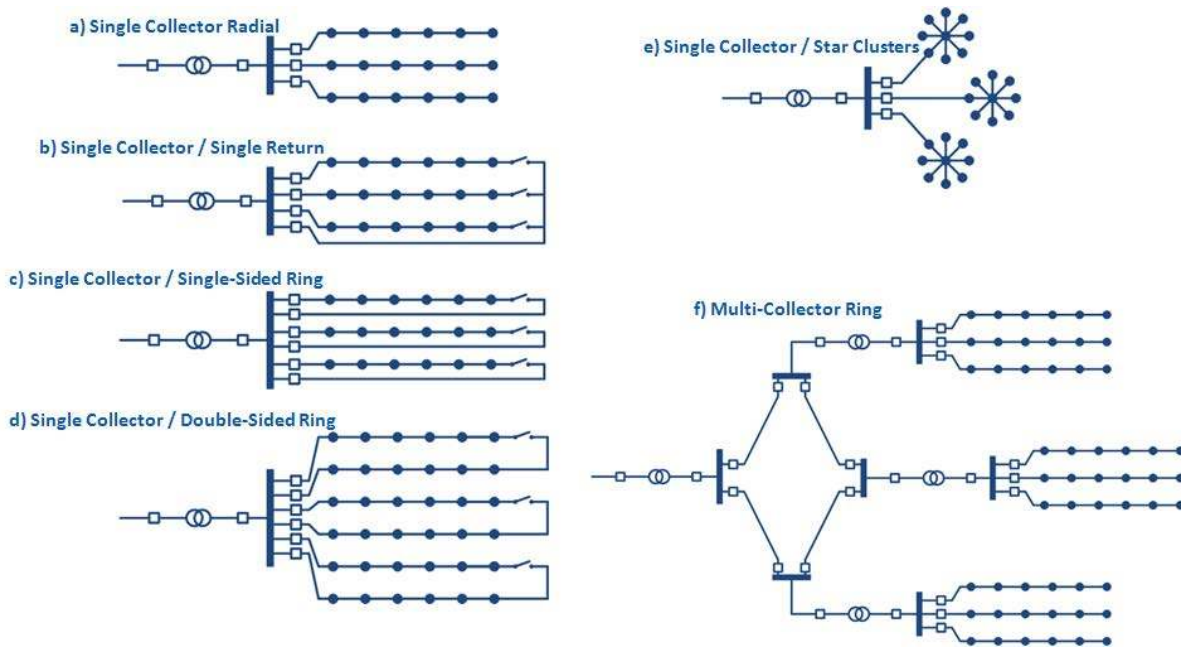


Figure C-11. Various AC collector system options for offshore wind power plants

With some additional cabling, various ring configurations become possible (see Figure C-11 [b], [c], and [d]). The advantage of ring layout is an increased reliability because redundant paths allow for the power flow in case of equipment failure in one string; however, this additional reliability comes at a higher cost because longer and higher capacity cables are needed in ring designs. In some cases, higher voltage collector systems must be utilized to achieve desired power capacities to make ring-type topologies possible. This approach can be achieved by adopting a 66-kV collector system (instead of the 33-kV system used in most projects). The transition to 66 kV has several benefits, including lower array electrical losses; however, to realize these benefits, efforts must be made to overcome technical issues related to the implementation of such voltages. The main barrier at this time seems to be the availability of dry type transformers.

An example star design is shown above in C-11 (e). It provides a higher level of reliability, but it requires more complex switchgear arrangements. A multicollector ring layout (Figure C-11 [f]) also enhances collector system security and allows for greater operational flexibility, but, again, it comes at a greater expense because multiple hub platforms and higher voltage collection is needed for such a configuration. It is a subject of separate study to examine both the steady-state and dynamic performance of various collector system layouts and to determine the most economic configuration for wind power plants of various capacities, wind turbine electrical topologies, and water depths.

Example parameters of 33-kV submarine cables used in offshore wind power plants are shown in Table C-14. Figure C-12 shows an example of cable cross sections used in a radial string with six wind turbines, each rated for 6 MW.

Table C-14. Parameters of 33-kV 3-Core XLPE Copper Cables with a Lead Sheath

Cross Section (mm ²)	Outer Diameter (mm)	Weight (kg/m)	Capacitance (μF/km)	Inductance (mH/km)	Resistance (ohm/km)	Current (A)
300 (Next Size to 500 kcmil)	123.9	26.2	0.26	0.36	0.0601	530
630 (Next Size to 1,000 kcmil)	145.1	40.9	0.35	0.32	0.0283	715
800 (Next Size to 1,500 kcmil)	154.4	47.2	0.38	0.31	0.0221	775

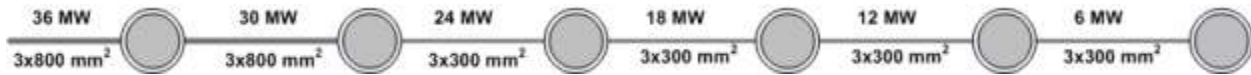
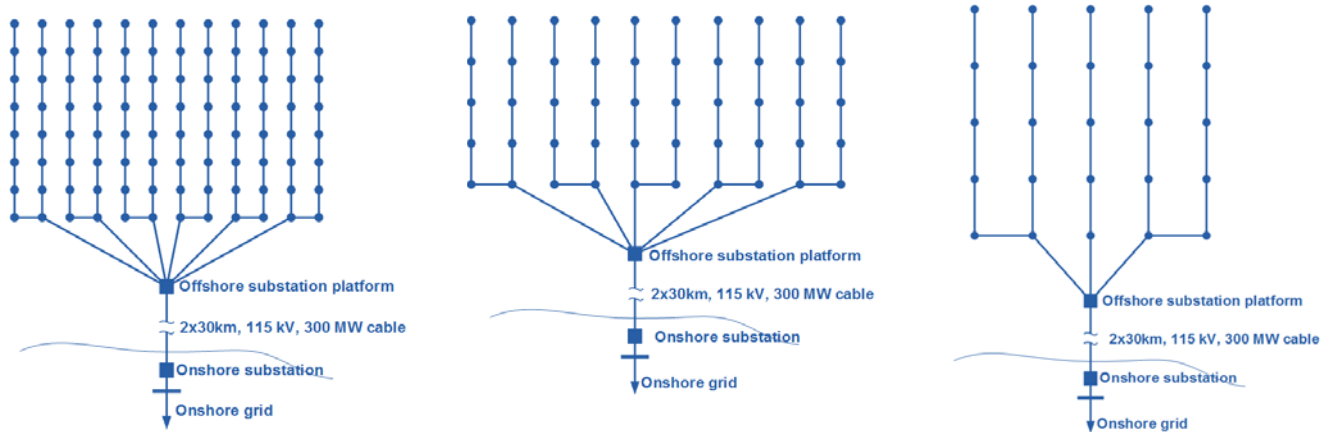


Figure C-12. Group of six turbines on the same radial string

Impact of Turbine Size on Offshore Balance-of-System Cost

A simple radial layout of a 250-MW wind power plant consisting of individual wind turbines of different capacities (3.6, 5, and 10 MW) with two 115-kV undersea transmission lines is shown in Figure C-13.



(a) 3.6-MW turbines

(b) 5-MW turbines

(c) 10-MW turbines

Figure C-13. An example 250-MW offshore wind power plant with various single-turbine capacities

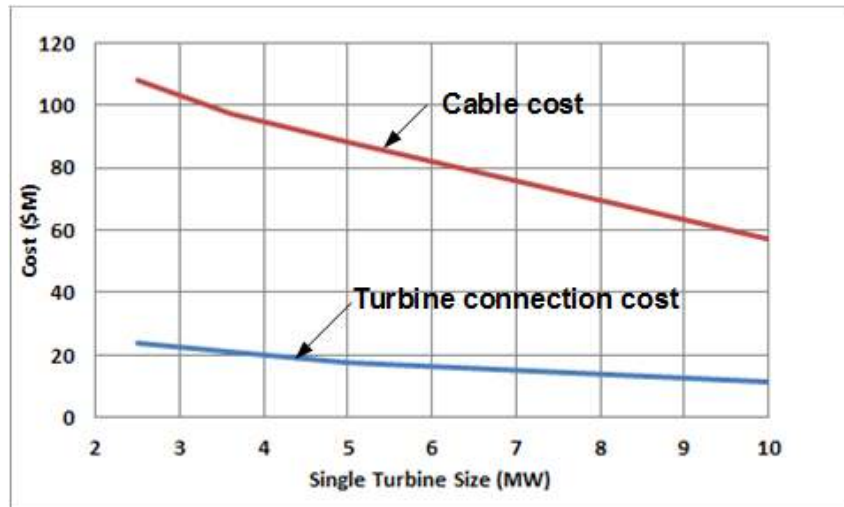


Figure C-14. Impact of turbine size on total cable and connection costs

The distance among individual wind turbines is kept constant at eight times the turbine diameter for all three cases. The diameters assumed were 107, 125, and 180 m for the 3.6-, 5-, and 10-MW cases, respectively. The costs of an internal 33-kV collector system for each case is then calculated based on cable lengths and cost (assumed \$1.5 M/km, including burial). As shown in Figure C-14, there is a significant cost difference in both total cable and turbine connection costs depending on individual turbine size. For this example of a hypothetical 250-MW offshore wind power plant, both cable and connection costs are decreased by almost twice if 10-MW wind turbines are used instead of 3.6-MW turbines. These savings represent an approximately 5%–6% reduction in overall project cost for a 250-MW offshore wind power plant. The savings for an actual wind power plant will vary depending on the plant’s layout and distances among wind turbines (both within and among rows). The common practices in European offshore projects are spacings of 5–10 rotor diameters among wind turbines in the row and 7–12 rotor diameters among rows.

Floating offshore wind power projects have different electrical cable design requirements than fixed-bottom projects. Note that such a difference is mainly reflected in the mechanical design of the cable to withstand additional structural loads associated with the dynamic nature of the operation. From an electrical viewpoint (e.g., collector cable arrangement shown in Figure C-15), the operation of floating or fixed-bottom offshore wind power plants is very similar. In this work, we assumed that the electrical characteristics of dynamic cables are similar to the XLPE cables traditionally used in conventional offshore power plants. The XLPE cables should have adequate conductor cross sections to meet the system requirements for electrical power transmission capacity. The cost of energy losses can be reduced by using cables with larger cross sections. Load losses in XLPE cables are primarily caused by the ohmic resistance of the conductor. In general, three important factors that greatly impact the selection of cables for submarine applications are ampacity, electrical length, and capacitive current. AC submarine cables have larger shunt capacitances so the resulting charging current will limit the cable ampacity, reducing its real power transfer capacity and increasing losses. Inductive shunt compensation is often used to reduce these impacts at single or both ends of export high-voltage cables.

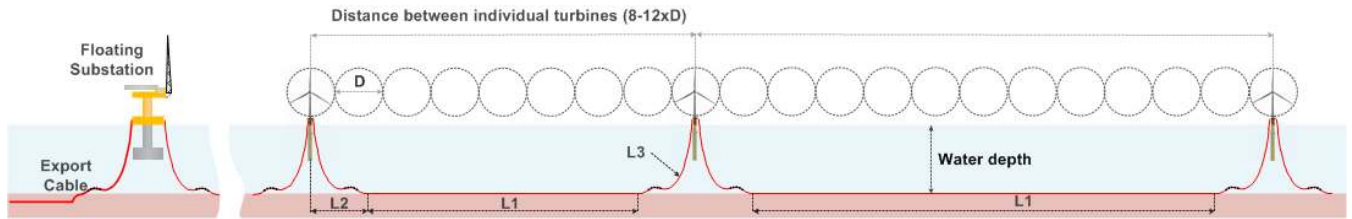


Figure C-15. Example collector system arrangement with floating cable segments

Offshore Turbine Connection Methods

Various methods of individual turbine connections to offshore collector networks and cable protection methods have been described in the literature [2], [7]. Some possible methods are shown in Figure C-16. The J-tube method has been used widely in wind power plants with monopile foundations (Figure C-16 [left]). The J-tubes can be made of plastic or steel and are designed to provide protection to the power cable and withstand the scour protection method. Expensive sea labor (such as diver operations) may be required for installing cables using this method. A hinged J-tube method can be used to eliminate a need in scour protection and reduce the amount of labor associated with the turbine connection. A directional drilling method (Figure C-16 [middle]), although more expensive, provides better protection for a cable inside of a monopile foundation, eliminates the need for J-tubes, and the cable is not exposed to ice or wave loading. The monopile foundation is drilled from the top using a directional drill rig, then drilling is continued in the soil, thereby providing proper bending radius for the cable.

The cost of the turbine connection will be reduced significantly for the floating platform design (Figure C-16 [right]). In this case, a special mooring and floating tension relief will be needed for the power cable to minimize its exposure to hydrodynamic loading.

The turbine's connection cost is relatively small in the overall BOS budget (1%–2%); however, the reliability of a wind power plant's operation is impacted by the connection method.

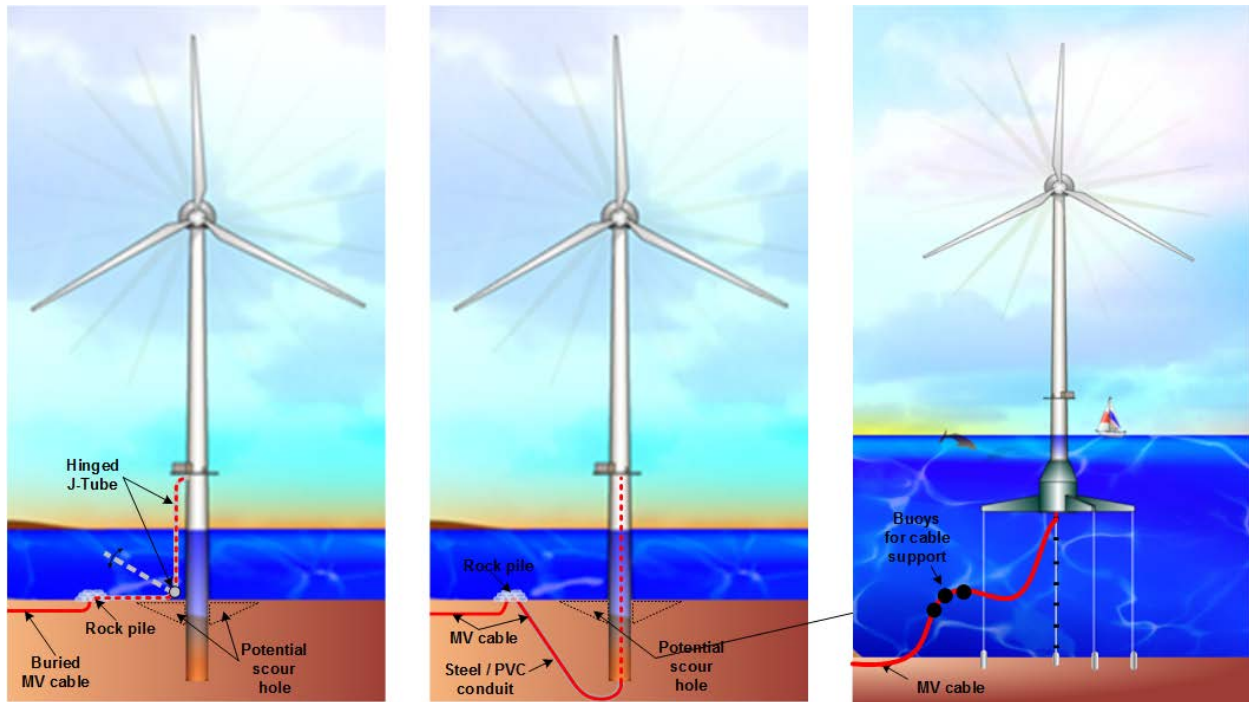


Figure C-16. Examples of individual turbine connection methods

Submarine Transmission

The interconnection of a variable generation source such as offshore wind power via a high-voltage alternating current (HVAC) link requires that common rules concerning reliability, stability, voltage, frequency control, and so on need to be respected. In most cases, more than one AC link may be necessary for reliability purposes. Submarine AC power cables create a wide variation of voltage along the AC cable at different levels of power flow. To adjust the voltage and compensate for the reactive power generated by the cable capacitance, shunt reactors are usually installed at both ends of the AC cable (see example in Figure C-17). The maximum practical distance for submarine transmission has a limit of approximately 100 km for XLPE cables that have lower shunt capacitances than other cable types. Beyond this distance, HVDC is the only technically viable solution.

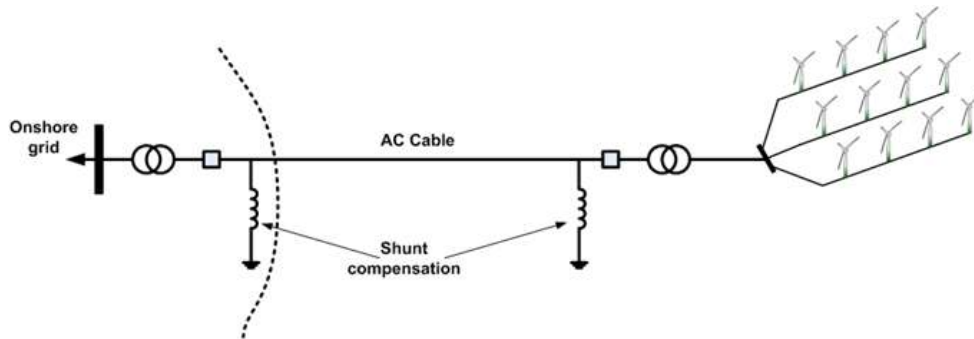


Figure C-17. AC interconnection of an offshore wind power plant

Shunt reactors are connected in parallel to the export cable to compensate for reactive power. For the fixed voltage, the reactive power consumed by the shunt reactor will increase for smaller inductors. The voltage drop is not uniform across the export cable so the amount of reactive power absorbed by the shunt reactor will depend on its position relative to the length of cable. The loading of an open-ended export cable due to charging current for two different shunt capacitor placement options is shown in Figure C-18. Ideally, the shunt compensation must be placed at both ends of the cable. Placement of the shunt compensation on one end will have a lesser effect, but it will also have no impact on the cost of the floating substation. In this analysis, we will investigate the need for shunt compensation only at the receiving end of the export cable.

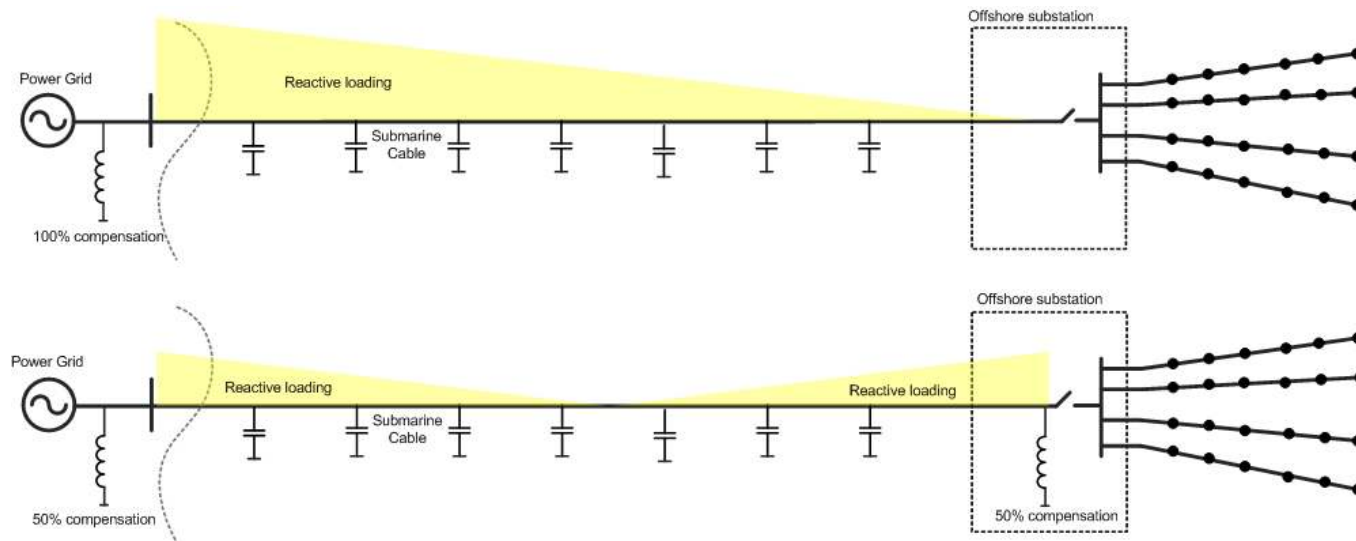


Figure C-18. Shunt compensation options

HVDC transmission enables the secure and stable asynchronous interconnection of electric power grids with instant and accurate control of power, contributing to improved stability and reliability, increased transmission capacity, improved interconnection compliance among multiple areas, and greater integration of variable renewable generation. There are no technical limits to the potential length of an HVDC cable for overhead, underground, and submarine power transmission to deliver the energy generated by renewable sources to major load centers; however, systems with significant amounts of HVDC transmission behave in a fundamentally different way compared to those of conventional AC systems. Integrating HVDC technologies into the transmission infrastructure introduces new challenges because of faster dynamics and different means of controlling the power system at many different timescales as well as new opportunities to incorporate HVDC systems as components of faster and more efficient smart grid controls. Many research papers indicate the value and economic benefits of HVDC technology for interconnecting offshore wind power plants that are located farther distances from the shore (50–70 km and farther).

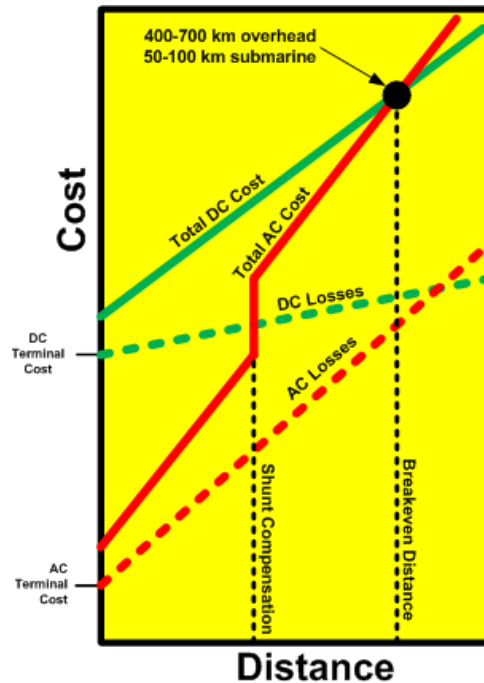


Figure C-19. DC and AC transmission cost multipliers

As shown in Figure C-19, the initial terminal cost for HVAC interconnection is much lower than that for HVDC because of the high cost of power electronic converter stations used in HVDC transmission. The cost of transmission line construction is lower for HVDC than for HVAC because fewer and lighter cables are needed for HVDC. After a certain distance, the offshore HVAC requires a shunt compensation, which can be installed only at the sending and receiving ends of the cable, thus further increasing the cost of the HVAC system. Losses in HVDC are lower for the same amount of power than HVAC. The breakeven distance is achieved when total HVDC and HVAC costs are equal to each other (50 km–100 km for offshore, 450 km–700 km for overhead transmission). The other components that need to be included in the comparison are the energy availability of the transmission system and additional HVDC benefits, such as power flow and voltage control and limitations of the short-circuit level. There are two basic HVDC transmission technologies: line-commutated converter (LCC) using thyristors and voltage source converter (VSC) using insulated-gate bipolar transistors. The LCC HVDC has been around for many years with proven reliability and can be used at very high power levels. It is necessary to provide a commutation voltage for the LCC converter to operate. This commutation voltage has traditionally been supplied by synchronous generators or compensators in the AC power grid. This dependence on stiff AC voltage on its terminals is the main restricting factor for LCC HVDC in offshore applications.

VSCs have been used in HVDC transmission systems throughout long distances both on land and in submarines for the past 10 years–15 years. Many of the advantages of LCC HVDC apply to VSCs as well; however, VSCs provide many additional benefits, especially for offshore wind applications. An example of a monopolar VSC HVDC system is shown in Figure C-20. An example of a bipolar VSC HVDC interconnection for an offshore wind power plant is shown in Figure C-21.

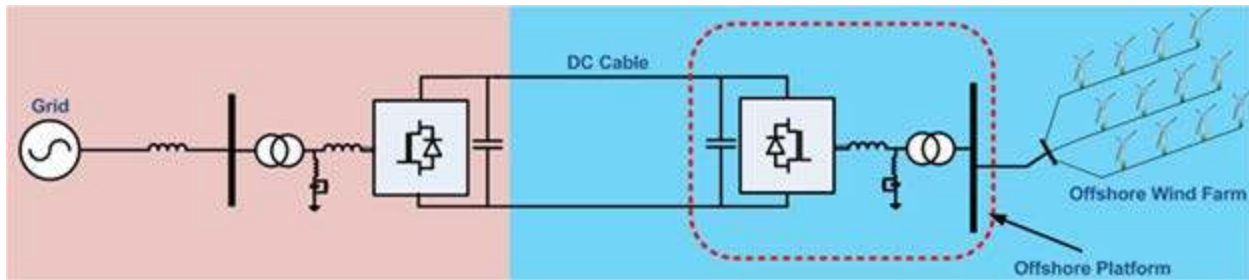


Figure C-20. Example of a monopolar WSC HVDC system for an offshore wind power plant

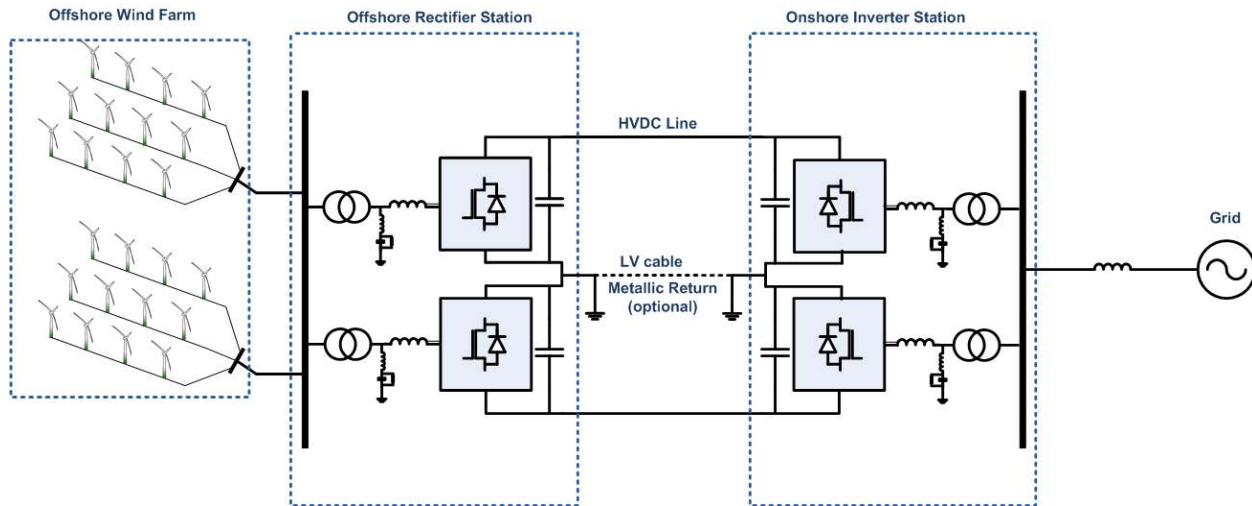


Figure C-21. Example of a bipolar WSC HVDC interconnection for an offshore wind power plant

The WSCs are self-commutating and do not require an external voltage for operation; therefore, no reactive power compensation is needed to support power transmission over WSC HVDC. The WSC solution is able to supply and absorb reactive power to the system and help support power system stability. In fact, the reactive power flow can be controlled independently on active power at both the sending and receiving ends of WSC HVDC transmission. No large AC harmonic filters are required at both ends because of higher switching frequencies; however, the switching losses are higher than those for the LCC HVDC by approximately 1%–1.7%. The WSC HVDC can use regular transformers, and no minimum short circuit-level restriction is applied to WSCs. In general, the WSC HVDC is considered a better solution for weaker systems or systems with a high level of variable generation. These features make WSC HVDC transmission attractive for the connection of large offshore wind power plants. There are three major manufacturers of WSC HVDC equipment: ABB (HVDC Light), Siemens (HVDC Plus), and Alstom/Areva.

In the case of an AC network fault, the DC-link voltages of WSC HVDC will rise rapidly because wind turbines will continue pumping power into the DC line. To maintain the DC-link voltage within safe limits, the excess power must be dissipated or the wind power must be curtailed. A chopper circuit can be installed in the DC link for protection purposes. The WSC HVDC provides better light-voltage ride-through conditions for an offshore wind power plant because it provides full isolation between the plant and the land-based grid voltages. The WSC

HVDC also provides a rapid black-start capability for an offshore wind power plant because plant voltage and frequency can be set and maintained by the sending end of the WSC converter.

The submarine transmission line for interconnecting the offshore wind power plant to the land-based power grid is one of the most significant BOS cost contributors, representing 10%–15% of the overall BOS budget; therefore, selecting the most economical and technically superior transmission method and carefully evaluating all of the associated factors (e.g., electrical losses and grid integration aspects) is essential for reducing the cost of the BOS electrical component. For the same 250-MW wind power plant example, the cost of two three-phase, 115-kV, single-core submarine cables (30-km long) can be as high as \$80–\$100 million for depths of up to 100 m, including burial along the whole length of the cable (approximately \$2 million/km for a single cable). The cost of an offshore platform for a transformer, collector bus, and protection equipment can be as high as \$15–25 million for a 250-MW wind power plant.

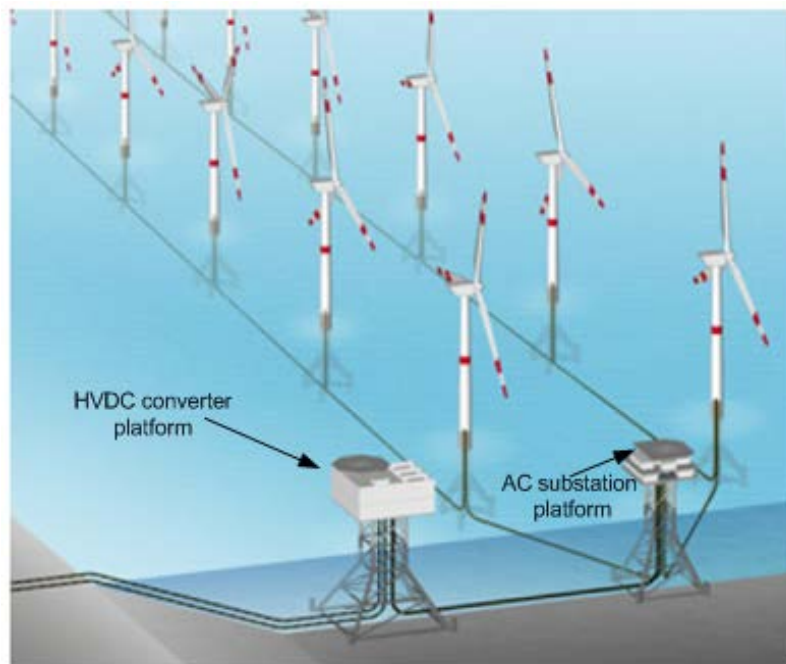


Figure C-22. Offshore wind power plant and platforms.
Illustration from NSW



Figure C-23. Siemens Helwin HVDC platform. *Image from Siemens Energy*

For longer transmission distances when HVDC technology is justified, a second offshore platform may be needed for the HVDC converter station at the wind power plant (see example shown in Figure C-22). In most cases, both AC and DC platforms can be combined, thereby cutting the cost significantly. The cost of an HVDC converter platform will be much higher than that for an AC substation platform of the same power capacity. Only a few offshore wind power plants use HVDC technology at this point in time so it is hard to make assumptions about HVDC platform costs. Projects of this nature are located more than 100 km off the German coast in the North Sea. For example, BorWin1 (400 MW) and Dolwin1 (800 MW) offshore projects have been in operation for a few years and are now utilizing ± 150 -kV and ± 320 -kV HVDC links, respectively. In the North Sea, Siemens Energy and Prysmian have erected the Helwin HVDC links between the Amrumbank West offshore wind power plants and the land-based grid. This Helwin 1-HVDC platform is rated for 576 MW and links the two offshore wind power plants (Nordsee Ost and Meerwind) to the mainland. The HelWin offshore converter platform (Figure C-23) houses the HVDC converter station, power transformers, gas-insulated high-voltage switchgear, and so on. The station was delivered on a floating, self-erecting platform and towed by tugs to its destination in open sea, where the water is 23 m deep.

The cost of submarine HVDC cables varies depending on water depths, transmission capacity, and voltage. For example, a monopile 150-kV DC 250-MW submarine cable is estimated at approximately \$1.5 million/km–2 million/km. The cost of a land-based converter station is estimated at approximately \$0.1 million/MW.

Advances in submarine power transmission technology, HVDC converter station cost reductions, and implementations of advanced deployment methods can contribute significantly to the overall

decrease of submarine HVDC transmission costs, making the interconnection of wind power plants located at farther distances from the shore more economical.

Offshore Supergrids to Reduce the Cost of Wind Power Plant Interconnections

Another advantage of WSC HVDC transmission technology is the prospect of relatively easy multiterminal operation, which makes the creation of offshore DC supergrids possible.



Figure C-24. European offshore supergrid proposal. *Illustration from SSE Airtricity (2016)*

The idea of an offshore supergrid was first introduced in Europe for connecting and integrating geographically dispersed offshore wind power plants throughout the European continent (Figure C-24). By providing interconnections among electricity systems, the supergrid helps overcome barriers to establishing a single internal market for electricity and creates a more competitive electricity supply in Europe by allowing for the fast transportation of power produced by offshore wind power plants to the regions of demand. As a result, this interconnection helps reduce the cost of energy produced by offshore wind.

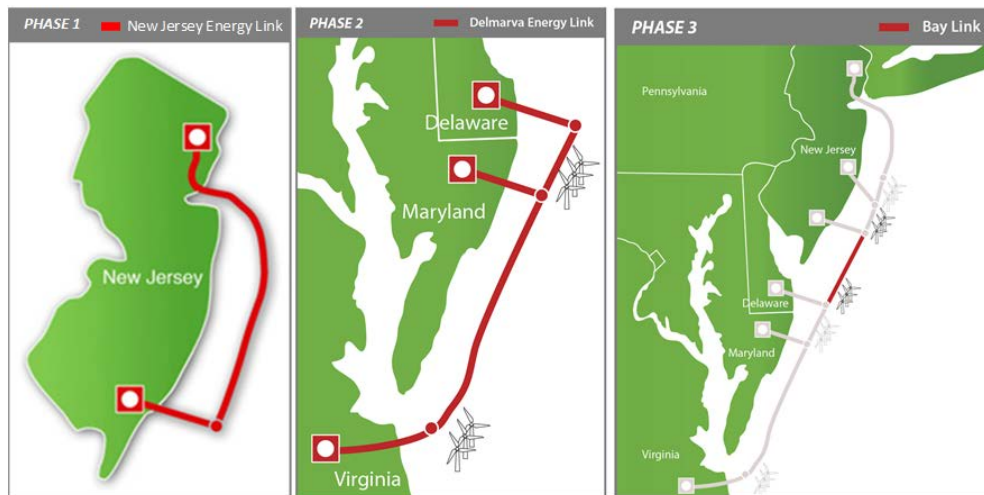


Figure C-25. Proposed Atlantic Wind Connection project with three phases. *Image from <http://www.atlanticwindconnection.com>*

A similar idea—but on a smaller scale—was proposed in the Atlantic Wind Connection backbone transmission project.⁵¹ The anticipated backbone HVDC transmission along the U.S. mid-Atlantic Coast will be deployed in three phases (shown in Figure C-25) and is supposed to allow for easier the integration and control of multiple wind power plants while avoiding the electrical losses associated with HVAC lines. With the strong backbone in place, larger and more energy-efficient wind power plants can connect (at a lower cost) to offshore hubs further out to sea. These power hubs will in turn be connected via subsea cables to the strongest, highest-capacity parts of the land-based transmission system. If needed in the future, the multiterminal configuration will allow for the expansion of the backbone HVDC farther north, south, or east into the Atlantic, where shallow banks suitable for offshore wind power plants exist. Such backbone HVDC lines should significantly reduce the cost of interconnection of offshore wind power plants because they eliminate the need for costly individual offshore transmission lines to the shore.

⁵¹ Source: <http://atlanticwindconnection.com/awc-projects/project-phases/New-jersey-energy-link>

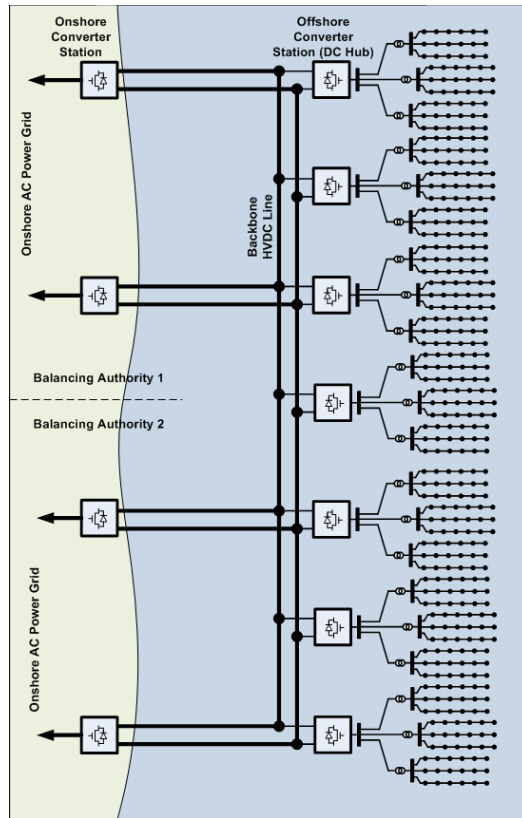


Figure C-26. Offshore HVDC backbone concept

The concept of an offshore HVDC backbone line is shown in Figure C-26. There are two different control approaches for the multiterminal HVDC. One approach is the master-controlled architecture wherein one WSC station controls the DC-link voltage and other stations control power flows. In the event of a master failure, another WSC converter will assume its function. The second approach is based on a coordinated control concept wherein all WSCs control both the DC-link voltage and power flows in a coordinated effort based on reliable communications among stations. Various interconnection topologies for a multiterminal HVDC are possible for offshore wind power plants. The power capacity of a submarine monopolar WSC-based HVDC transmission is still limited at hundreds of megawatts so several parallel HVDC lines (monopile or bipole) will be needed for such a backbone using today’s technology; however, WSC HVDC capacities will increase in the future because of rapid progress in this area.

Advanced DC Collector Systems for Offshore Wind Power Plants

As an alternative to increasing the AC voltage levels in offshore wind power plant collector systems, medium-voltage DC (MVDC) collector systems represent many cost saving and performance improvement opportunities for offshore wind power [11]. One of several possible MVDC collector system concepts is shown in Figure C-27. Using medium-voltage rectifier equipment in individual offshore wind turbines allows eliminating a need for a wind turbine transformer and an additional conversion stage. DC power from individual wind turbines is collected in the MVDC platform, inverted back to AC, and stepped up to a transmission voltage level by the platform transformer.

The advantages of MVDC-based offshore wind power plants are higher overall electrical efficiency, reduced turbine weights (no transformer), lighter and less expensive inter-turbine cables, and improved wind power plant controllability. Further research in this area is needed to quantify potential cost savings introduced by MVDC collector technology for offshore applications.

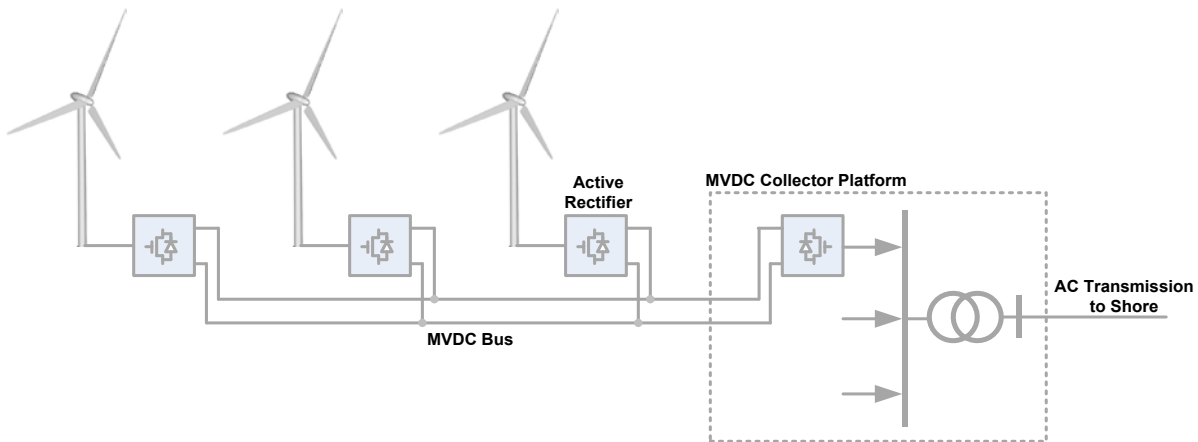


Figure C-27. Concept of a MVDC collector system

C.2.3 Installation Parameter Study

NREL developed a parameter study to investigate how CapEx changes with respect to logistical distances, metocean conditions, and turbine nameplate capacity or size. Key parameters that were analyzed include water depth, which drives vessel selection and substructure size and mooring lengths for fixed and floating substructures, respectively; the turbine size, which drives substructure size and vessel selection; and the distances from the staging port to the project site, from the staging port to the inshore assembly area, and from the assembly area to the project site. Three turbine sizes (3 MW, 6 MW, and 10 MW) and four substructure types (monopile, jacket, spar, and semisubmersible) were considered, resulting in 12 total scenarios. Each of the key parameters was varied to understand the sensitivity of installation costs to the change in each parameter as well as how installation costs differ among technologies. This analysis was performed using NREL offshore BOS cost model. Turbine parameters were varied for each scenario, and costs were modeled based on a 600-MW commercial-scale wind power plant. Table C-15 shows the turbine parameters and number of turbines modeled for each of the turbine sizes analyzed in this study. The parameters that were varied during the analysis are listed in Table C-17.

Table C-15. Turbine and Wind Power Plant Parameters

Parameter	3-MW Turbine	6-MW Turbine	10-MW Turbine
Rotor Diameter (m)	90	155	205
Hub Height (m)	75	97	125
RNA Mass (t)	175	365	677
Number of Turbines	200	100	60

Each substructure has a unique installation strategy and installation vessel spread. Monopile and jacket substructures are installed using a main installation vessel that loads components onto its deck at port for transportation to the project site where the substructure and turbine components are assembled and installed. Vessel requirements differ between monopile and jacket substructures because of the differences in size and weight. Spars require that the turbine is installed at a sheltered inshore assembly area due to the large draft of the spar substructure that must be upended to install the turbine. Once assembled, the turbine-spar assembly is then towed to the project site and attached to the preinstalled mooring and anchor system. Semisubmersible substructures are towed to the staging port where the turbine is assembled and installed onto the semisubmersible. The complete assembly is then towed to the project site where it is attached to the preinstalled mooring and anchor system.

Table C-16. Key Parameter Ranges and Increments

Variable	Fixed Substructure	Floating Substructure
Water Depth	10–100 m, 10-m increments	66–1,000 m, varying increments
Distance from Port to Site	50–500 km, 50-km increments	50–500 km, 50-km increments
Distance from Port to Assembly Area	—	50–500 km, 50-km increments (spar only)
Distance from Assembly Area to Site	—	50–500 km, 50-km increments (spar only)

Vessel selection for fixed substructures was driven by the main installation vessel’s operational limits. These limits include the maximum operational water depth, the maximum payload, and the maximum lifting capacity. Vessel selection for floating substructures is driven by bollard pull requirements for towing and anchor and mooring installation and tensioning. Vessels used for fixed substructure installation are shown in Table C-17, and vessels used for floating substructure installation are listed in Table C-18. Vessel strategies for fixed substructures and floating substructures are shown in Table C-19 and Table C-20, respectively.

Table C-17. Fixed-Bottom Substructure Installation Vessels. Photos provided by DONG Energy (Sea Power), Maritime Journal (MPI Resolution), MPI Offshore LTD (MPI Adventure), Swire Blue Ocean (Pacific Orca), and Heerema Marine Contractors (Thialf)


Vessel (From Offshore BOS Model)	Description	Max Payload (tonne)	Max Lift Capacity (tonne)	Max Operational Water Depth (m)	Comparable Industry Vessel	
Mid_Mid_Sized_Jack_Up_Vessel	Low capacity, low jack up height	1910	317	33.8	Sea Power	
Mid_Large_Sized_Jack_Up_Vessel	Medium capacity, low to medium jack up height	4400	717	45	MPI Resolution	
High_Mid_Sized_Jack_Up_Vessel	Medium to high capacity, medium jack up height	5750	1130	48.3	MPI Adventure	
High_Large_Sized_Jack_Up_Vessel	High capacity, high jack up height	8000	1375	57.8	Pacific Orca	
Semi_Submersible_Crane_Vessel	High cargo capacity, high lift capacity	10,000	7,100/14,200 single/tandem	∞	Thialf	

Table C-18. Floating Substructure Installation Vessels

Semisubmersible Vessel Spread		Spar Vessel Spread	
Vessel	Description	Vessel	Description
Medium anchor-handling support tug	Medium-bollard pull tug leading installation group	Medium anchor-handling support tug	Medium-bollard pull tug leading installation group
Large anchor-handling support tug	High-bollard pull tug leading installation group	Large anchor-handling support tug	High-bollard pull tug leading installation group
Support tug	Low-bollard pull, used for steering and positioning	Support tug	Low-bollard pull, used for steering and positioning
—	—	Medium barge	Used at inshore assembly area as an installation platform
—	—	Large barge	Used at inshore assembly area as an installation platform

Table C-19. Matrix of Strategies for Fixed Substructure Installation

		Lift Type											
		Light Lift					Medium Lift				Heavy Lift		
		1–300 t					300–700 t				700+ t		
Water Depth (m)	10	Strat 1	Strat 2	Strat 3	Strat 4	Strat 5	Strat 2	Strat 3	Strat 4	Strat 5	Strat 3	Strat 4	Strat 5
	20	Strat 1	Strat 2	Strat 3	Strat 4	Strat 5	Strat 2	Strat 3	Strat 4	Strat 5	Strat 3	Strat 4	Strat 5
	30	Strat 1	Strat 2	Strat 3	Strat 4	Strat 5	Strat 2	Strat 3	Strat 4	Strat 5	Strat 3	Strat 4	Strat 5
	40	***	Strat 2	Strat 3	Strat 4	Strat 5	Strat 2	Strat 3	Strat 4	Strat 5	Strat 3	Strat 4	Strat 5
	50	***	***	Strat 3	Strat 4	Strat 5	***	Strat 3	Strat 4	Strat 5	Strat 3	Strat 4	Strat 5
	60	***	***	***	Strat 4	Strat 5	***	***	Strat 4	Strat 5	***	Strat 4	Strat 5
	70	***	***	***	***	Strat 5	***	***	***	Strat 5	***	***	Strat 5
	80	***	***	***	***	Strat 5	***	***	***	Strat 5	***	***	Strat 5
	90	***	***	***	***	Strat 5	***	***	***	Strat 5	***	***	Strat 5
	100	***	***	***	***	Strat 5	***	***	***	Strat 5	***	***	Strat 5

Strategy	Strat 1	Strat 2	Strat 3	Strat 4	Strat 5
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Description	Lowest cost, shallow water depths, small turbine sizes	Low cost, shallow to medium water depths, small to medium turbine sizes	Medium cost, medium water depths, medium to large turbine sizes	High cost, deepwater depths, large turbine sizes	Very high cost, not constrained by water depth, largest turbine sizes
Installation Vessel	Mid_Mid_Sized_Jack_Up_Vessel	Mid_Large_Sized_Jack_Up_Vessel	High_Mid_Sized_Jack_Up_Vessel	High_Large_Sized_Jack_Up_Vessel	Semi_Submersible_Crane_Vessel

*** = Exceeds maximum operational water depth

Table C-20. Floating Substructure Installation Strategies

Semisubmersible			Spar		
Turbine Rating			Turbine Rating		
3 MW	6 MW	10 MW	3 MW	6 MW	10 MW
Semisubmersible Standard	Semisubmersible Standard	Semisubmersible Advanced	Spar Standard	Spar Advanced	Spar Advanced+
Strategy	Semisubmersible Standard	Semisubmersible Advanced	Spar Standard	Spar Advanced	Spar Advanced+
Description	Turbine installed onto substructure at port and towed to site for installation	Turbine installed onto substructure at port and towed to site for installation	Turbine and substructure towed to inshore assembly where turbine is installed onto spar and full assembly is then towed to site	Turbine and substructure towed to inshore assembly where turbine is installed onto spar and full assembly is then towed to site	Turbine and substructure towed to inshore assembly where turbine is installed onto spar and full assembly is then towed to site
Lead Vessel	Medium anchor-handling tug supply vessel	Large anchor-handling tug supply vessel	Medium anchor-handling tug supply vessel	Large anchor-handling tug supply vessel	Large anchor-handling tug supply vessel + 30% premium

Installation Parameter Study Results

Sensitivity analyses varying the key parameters considered in this study were performed using NREL’s offshore BOS model. The model’s output cost values are in dollars. These dollar cost outputs were used to develop curve-fit relationships that could estimate installation costs using the key parameters as inputs. Cost-estimation curve fits were divided into three categories:

substructure installation, which encapsulates all of the installation costs associated with the assembly and installation of the substructure; turbine installation, which includes all of the costs associated with assembly and installation of the turbine; and port, staging, and transportation costs, which include installation ancillary costs such as the cost of storage and staging components, component transport and crane costs, and port fees.

Curve fits were developed using a curve-fitting computer program called TableCurve 3D. This program was chosen because of its capability to fit curves to three-dimensional data and fit the data by utilizing a large variety of different mathematical relationships, which allows for more flexibility than simple linear or polynomial curve fits. TableCurve 3D also provides a graphical preview of the curve-fit relationship that is superimposed over the input data, which makes it easy to visually inspect curves for any anomalous trends and large deviations that may lead to unwanted uncertainty when using the derived relationships to estimate costs. Figure C-28 shows an example of curves that were fit for the monopile installation for the case of the 3-MW turbine.

3 MW Monopile

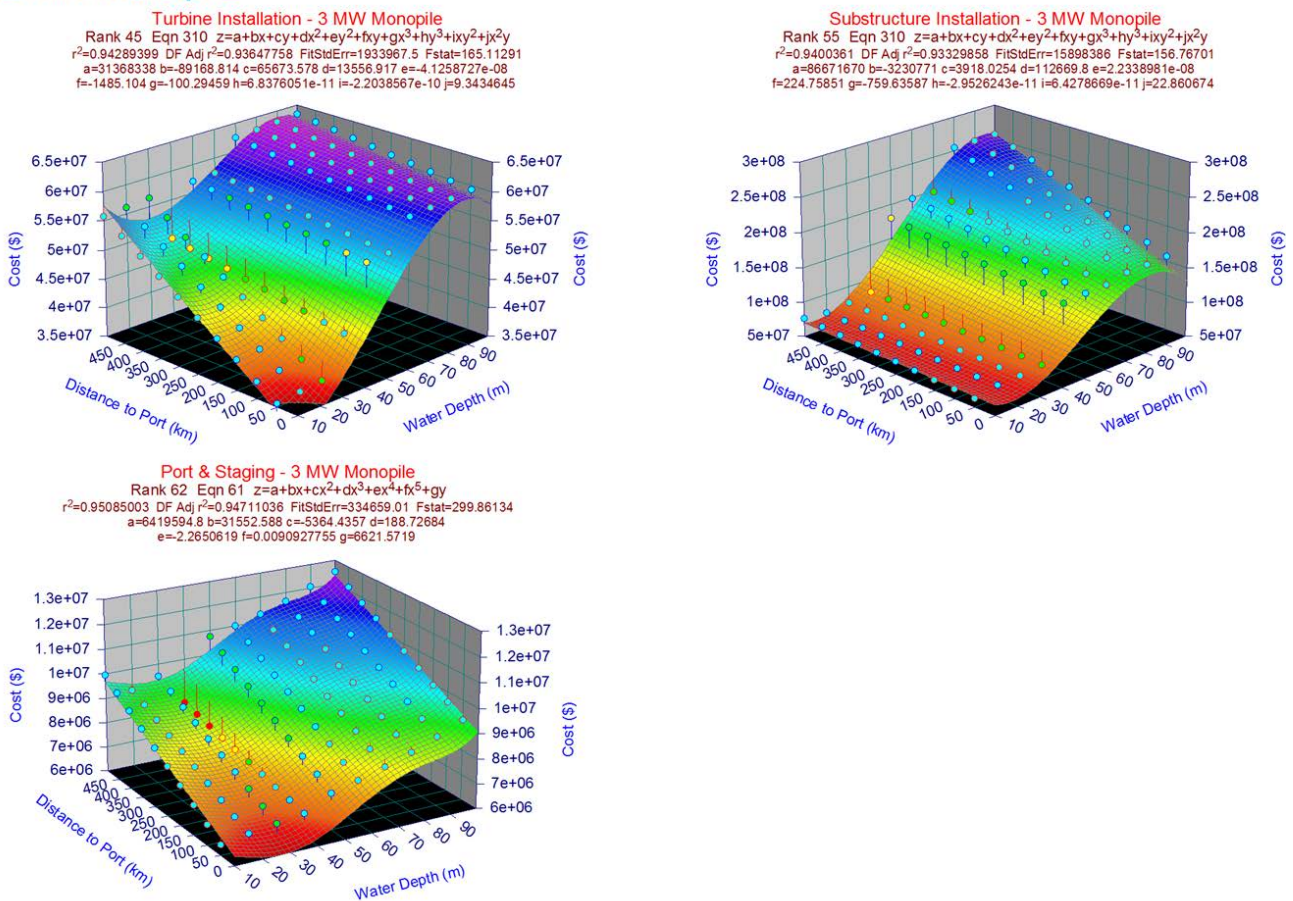


Figure C-28. Curve-fitting examples for the 3-MW monopile installation

The result of the curve-fitting exercise was a series of equations that estimated costs for each of the scenarios considered in this study. Table C-21 shows a description of the variables used in the estimating equations that follow.

Table C-21. Cost Equation Variables

Variable	Description
C_t	Turbine installation cost
C_s	Substructure installation cost
C_{ps}	Port and staging cost
D_p	Distance from staging port to project site
D_a	Distance from staging port to inshore assembly area
D_{as}	Distance from inshore assembly area to project site
W_d	Maximum water depth at project site

The following set of equations estimate costs for the 3-MW turbine case installed on a monopile substructure:

$$C_s = 86671670 - 3230771 \cdot W_d + 3918 \cdot D_p + 112670 \cdot W_d^2 + 2.23e^{-8} \cdot D_p^2 + 225 \cdot W_d \cdot D_p - 760 \cdot W_d^3 - 2.95e^{-11} \cdot D_p^3 + 6.43e^{-11} \cdot W_d \cdot D_p^2 + 22.9 \cdot W_d^2 \cdot D_p$$

$$C_t = 31368338 - 89169 \cdot W_d + 65674 \cdot D_p + 13557 \cdot W_d^2 - 4.13e^{-8} \cdot D_p^2 - 1485 \cdot W_d \cdot D_p - 100 \cdot W_d^3 + 6.84e^{-11} \cdot D_p^3 + 2.2e^{-10} \cdot W_d \cdot D_p^2 + 9.34 \cdot W_d^2 \cdot D_p \quad (\#)$$

$$C_{ps} = 6419595 + 31553 \cdot W_d - 5364 \cdot W_d^2 + 189 \cdot W_d - 2.27 \cdot W_d^4 + 0.009 \cdot W_d^5 + 6622 \cdot D_p$$

The following set of equations estimate costs for the 3-MW turbine case installed on a jacket substructure:

$$C_s = -22750257 + 20167344 \cdot W_d - 1061023 \cdot W_d^2 + 24429 \cdot W_d^3 - 246 \cdot W_d^4 + 0.903 \cdot W_d^5 + 100790 \cdot D_p$$

$$C_t = 30984338 - 38409 \cdot W_d + 65674 \cdot D_p + 12444 \cdot W_d^2 - 4.126e^{-8} \cdot D_p^2 - 1485 \cdot W_d \cdot D_p - 93.8 \cdot W_p^3 + 6.84e^{-11} \cdot D_p^3 - 2.2e^{-10} \cdot W_d \cdot D_p^2 + 9.34 \cdot W_p^2 \cdot D_p$$

$$C_{ps} = \frac{303606 + 743543 \cdot \ln W_d - 2244 \cdot D_p - 2.92 \cdot D_p^2}{1 - 0.851 \cdot \ln W_d + 0.273 \cdot (\ln W_d)^2 - 0.0269 \cdot (\ln W_d)^3 - 0.0003 \cdot D_p}$$

The following set of equations estimate costs for the 3-MW turbine case installed on a spar substructure:

$$C_s = 70146438 + 87703 \cdot D_a + 44830 \cdot D_p$$

$$C_t = 1.399e^8 + 19972 \cdot D_a + 270417 \cdot D_p$$

$$C_{ps} = 25237609 + 23896 \cdot D_a + 21667 \cdot D_p$$

The following set of equations estimate costs for the 3-MW turbine case installed on a semisubmersible substructure:

$$C_s = 18408000 + 7875 \cdot W_d + 24821 \cdot D_p$$

$$C_t = 48170500 + 95833 \cdot D_p$$

$$C_{ps} = 10472899 + 2000 \cdot W_d + 19002 \cdot D_p$$

The following set of equations estimate costs for the 6-MW turbine case installed on a monopile substructure:

$$C_s = 88705573 - 2965980 \cdot W_d - 7813 \cdot D_p + 104665 \cdot W_d^2 + 1.49e^{-6} \cdot D_p^2 + 661 \cdot W_d \cdot D_p - 707 \cdot W_d^3 - 1.71e^{-9} \cdot D_p^3 - 2.75e^{-11} \cdot W_d \cdot D_p^2 + 19.44 \cdot W_d^2 \cdot D_p$$

$$C_t = 15687102 + 2685414 \cdot W_d - 149549 \cdot W_d^2 + 3474 \cdot W_d^3 - 34.1 \cdot W_d^4 + 0.12 \cdot W_d^5 + 3133853 \cdot \ln D_p$$

$$C_{ps} = 7136675 - 21122 \cdot W_d + 1336 \cdot D_p + 449 \cdot W_d^2 + 0.009 \cdot D_p^2 + 58.2 \cdot W_d \cdot D_p$$

The following set of equations estimate costs for the 6-MW turbine case installed on a jacket substructure:

$$C_s = -4.58e^8 + 5.17e^8 \cdot \ln W_d + 809803 \cdot D_p - 1.59e^8 \cdot (\ln W_d)^2 + 1.89e^{-7} \cdot D_p^2 - 483412 \cdot D_p \cdot \ln W_d + 16772093 \cdot (\ln W_d)^3 - 1.57e^{-10} \cdot D_p^3 - 0.000000016 \cdot D_p^2 \cdot \ln W_p + 75746 \cdot D_p \cdot (\ln W_d)^2$$

$$C_t = -17171241 + 18311725 \cdot W_d - 12467174 \cdot W_d \cdot \ln W_d + 5716767 \cdot W_d^{1.5} - 172159 \cdot W_d^2 + 15946 \cdot D_p$$

$$C_{ps} = 12285015 + 77253 \cdot W_d + 11414 \cdot D_p - 740 \cdot W_d^2 - 0.26 \cdot D_p^2 - 220 \cdot W_d \cdot D_p + 2.78 \cdot W_d^3 + 0.0003 \cdot D_p^3 - 5.6e^{-10} \cdot W_d \cdot D_p^2 + 2.524 \cdot W_d^2 \cdot D_p$$

The following set of equations estimate costs for the 6-MW turbine case installed on a spar substructure:

$$C_s = 83062187 + 88643 \cdot D_a + 65900 \cdot D_p$$

$$C_t = 149900000 + 41598 \cdot D_a + 245417 \cdot D_{as}$$

$$C_{ps} = 26525267 + 25367 \cdot D_a + 21667 \cdot D_{as}$$

The following set of equations estimate costs for the 6-MW turbine case installed on a semisubmersible substructure:

$$C_s = 18408000 + 7875 \cdot W_d + 24821 \cdot D_p$$

$$C_t = 48170500 + 95833 \cdot D_p$$

$$C_{ps} = 12627913 + 2375 \cdot W_d + 22565 \cdot D_p$$

The following set of equations estimate costs for the 10-MW turbine case installed on a monopile substructure:

$$C_s = 1.7686e^8 - \frac{2.26e^6}{W_d} + 257702 \cdot D_p + \frac{1.21e^{10}}{W_d^2} + 1.82e^{-8} \cdot D_p^2 - 2558888 \cdot \left(\frac{D_p}{W_d}\right)$$

$$C_t = 57108119 + 1166746 \cdot W_d - 58333 \cdot W_d^2 + 1217 \cdot W_d^3 - 10.6W_d^4 + 0.032 \cdot W_d^5 + 24987 \cdot D_p$$

$$C_{ps} = \frac{7533930 - 116296 \cdot W_d + 1084 \cdot W_d^2 - 1.22 \cdot W_d^2 - 1425 \cdot D_p}{1 - 0.013 \cdot W_d + 8.83e^{-5} \cdot W_d^2 - 0.0005 \cdot D_p + 2.38e^{-7} \cdot D_p^2}$$

The following set of equations estimate costs for the 10-MW turbine case installed on a jacket substructure:

$$C_s = 1.27e^8 - 2490356 \cdot W_d + 174981 \cdot D_p + 80519 \cdot W_d^2 + 7.28e^{-8} \cdot D_p^2 - 4227 \cdot W_d \cdot D_p - 514 \cdot W_d^3 - 6.37e^{-11} \cdot D_p^3 - 4.5e^{-10} \cdot W_d \cdot D_p^2 + 49.24 \cdot W_d^2 \cdot D_p$$

$$C_t = 37087901 + 3946015 \cdot W_d - 199518 \cdot W_d^2 + 4192 \cdot W_d^3 - 37 \cdot W_d^4 + 0.116 \cdot W_d^5 + 26874 \cdot D_p$$

$$C_{ps} = 21321746 - 8043691 \cdot \ln W_d + 106665 \cdot D_p + 2496413 \cdot (\ln W_d)^2 - 0.26 \cdot D_p^2 - 56191 \cdot D_p \cdot \ln W_d - 219766 \cdot (\ln W_d)^3 + 0.0003 \cdot D_p^3 - 2.65e^{-8} \cdot D_p^2 \cdot \ln W_d + 7912.15 \cdot D_p \cdot (\ln W_d)^2$$

The following set of equations estimate costs for the 10-MW turbine case installed on a spar substructure:

$$C_s = 94577688 + 90048 \cdot D_a + 85033 \cdot D_p$$

$$C_t = 1.75e^8 + 73499 \cdot D_a + 290417 \cdot D_{as}$$

$$C_{ps} = 28101577 + 27188 \cdot D_a + 21667 \cdot D_{as}$$

The following set of equations estimate costs for the 10-MW turbine case installed on a semisubmersible substructure:

$$C_s = 23658000 + 11625 \cdot W_d + 35450 \cdot D_p$$

$$C_t = 59608000 + 120833 \cdot D_p$$

$$C_{ps} = 15896470 + 2975 \cdot W_d + 28266 \cdot D_p$$

To estimate costs throughout the range of turbine sizes from 3 MW–10 MW, a linear interpolation relationship was developed. The interpolation is described by the following equation:

$$x_c = \begin{cases} 3 \leq TR \leq 6, & \left| \frac{TR-3}{3} \right| C_6 + \left| \frac{TR-6}{3} \right| C_3 \\ 6 < TR \leq 10, & \left| \frac{TR-6}{4} \right| C_{10} + \left| \frac{TR-10}{4} \right| C_6 \end{cases}$$

where:

- x_c = interpolated installation cost
- TR = turbine rating in megawatts
- C_3 = 3-MW turbine installation cost function
- C_6 = 6-MW turbine installation cost function
- C_{10} = 10-MW turbine installation cost function.

The cost-estimating equations were confirmed to accurately estimate costs with a reasonable amount of error. These exercises mainly consisted of sensitivity analyses using the derived relationships and comparing the outputs to available industry data as well as outputs from higher fidelity, lower uncertainty internal models. The results of these verification exercises showed that the cost-estimating functions perform well throughout their respective variable ranges. Figure C-29 shows results from one of the sensitivities performed.

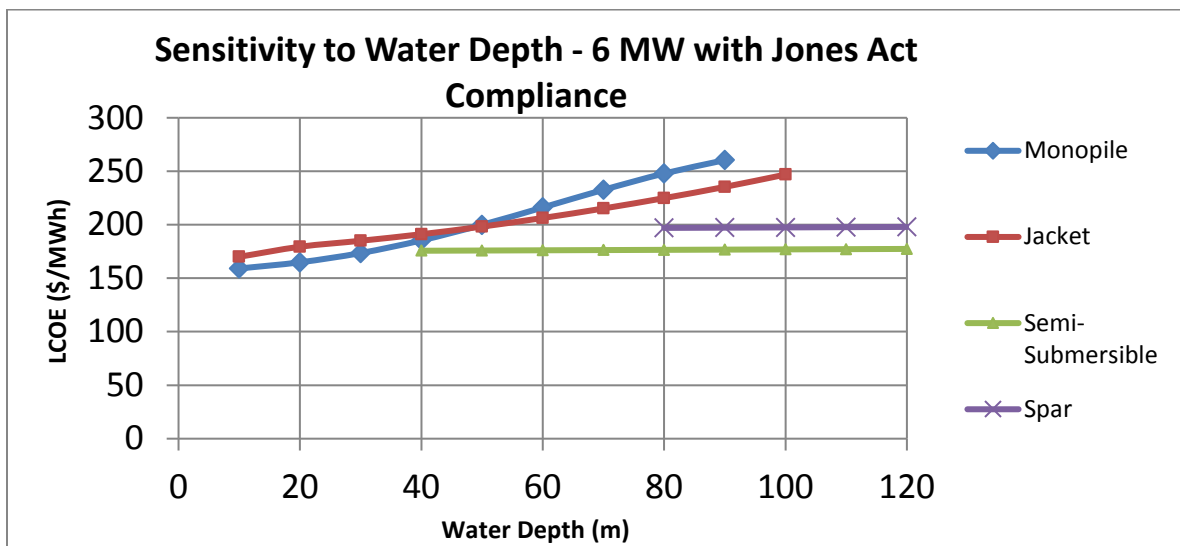


Figure C-29. Cost sensitivity to water depth for the 6-MW case with Jones Act compliance

Installation Parameter Study Cost multipliers

To reduce the estimation uncertainty and improve the robustness of the spatio-economic framework, NREL analysts developed installation cost multipliers that would be applied at

various stages of the cost estimation. One of the key factors developed was a Jones-Act-compliant cost multiplier that was necessary to account for additional costs that would be associated with developers being unable to utilize Europe’s substantial fleet of specially designed wind power plant installation vessels. Another factor was developed to scale the installation duration with turbine size because it is likely that as component sizes increase the time required for assembly and installation of those components will also increase.

The Jones Act factor assumes that developers in the United States will be unable to utilize the European fleet of purpose-built wind power plant installation vessels. This is because the Jones Act stipulates that only U.S.-flagged vessels can make consecutive trips from one U.S. port to another. New regulations have also stated that an offshore wind power plant is classified as a U.S. port, meaning that only U.S.-flagged vessels can make trips from a U.S. port to the project site; therefore, it is likely that the most cost-effective solution is to utilize the existing fleet of capable U.S.-flagged vessels for installation activities rather than mobilizing a vessel from Europe, which would not be allowed to dock at a U.S. port after leaving the project site. This solution is expected to have higher costs because without the use of specially designed installation vessels, installation activities will likely require a larger vessel spread and increased time to complete the installation. The Jones Act cost multiplier was developed by analyzing the differences in cost between using a European, purpose-built turbine installation vessel for installation and utilizing only U.S.-flagged vessels capable of performing the same installation. The cost differences were used to build an average cost percent adder that could be applied to installations assuming the use of a European turbine installation vessel to estimate the cost of a Jones Act-compliant installation using only U.S.-flagged vessels. Figure C-30 shows the cost addition results and an example of the estimation technique.

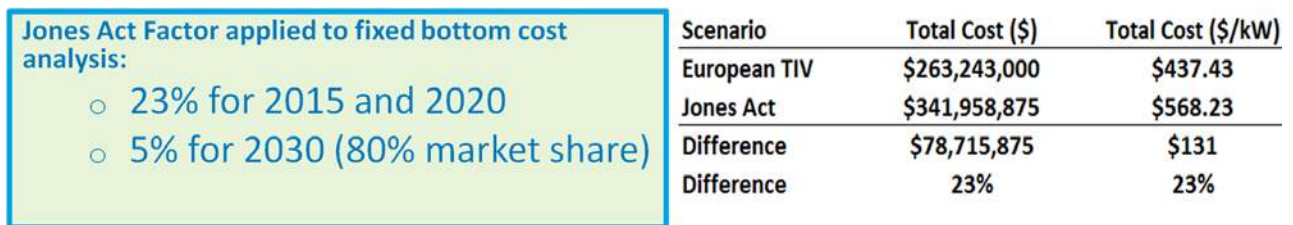


Figure C-30. Jones Act cost multiplier estimation and results

Another key factor that was developed during this analysis was a turbine-size installation timing factor. The offshore BOS model used to analyze the costs of installation does not take into account installation duration changes that are likely to occur as the turbine sizes change. For fixed substructures, this change is estimated to be significant because the turbine size, substructure size, and resulting vessel and installation strategy are directly linked. NREL analysts developed a cost multiplier that accounts for increases in installation duration as a result of increases in turbine size that can be applied to the substructure and turbine installation. The result is a linear scaling factor that can be found using the equation below. Figure C-31 gives a graphical representation of this relationship. Note that this factor is qualitative and based on NREL’s experience and knowledge of the industry, which needs to be substantiated with real data.

$$y = 0.0716 \cdot x + 0.7797$$

where:

- y = installation duration adjustment factor
- x = turbine size in megawatts.

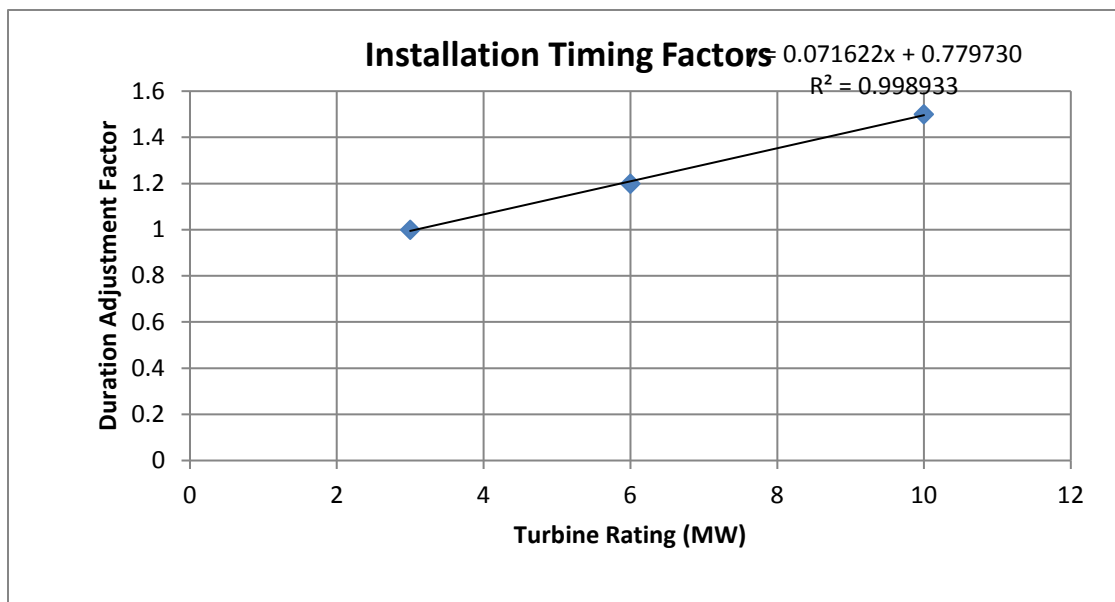


Figure C-31. Installation duration adjustment factors

C.2.4 Operational Expenditures

OpEx is expected to vary considerably among offshore wind power plant locations. From previous experience (Maples et al. 2013; Jacquemin et al. 2011; Pieterman et al. 2011), the two largest locational drivers of O&M cost differences among offshore wind power projects are the distances among the project and maintenance facilities (e.g., O&M port and/or inshore assembly area) and the prevailing metocean climate at the project site.⁵²

The Energy Research Centre of the Netherlands (ECN) O&M tool is used to investigate the sensitivity of OpEx costs to these spatial parameters, holding constant assumptions about technology and project characteristics. This assessment assumes three scenarios where major repairs are addressed by (1) an in situ repair strategy using a jack-up crane vessel for turbines fixed to the ocean floor (e.g., monopile or jacket substructures), (2) a tow-to-port strategy that uses a crawler crane portside for floating substructures that do not require deepwater drafts (e.g., semisubmersible), and (3) a tow-to-assembly area strategy for floating substructures that require deepwater ports (e.g., spar) and therefore require mobilization of a floating barge with a crawler crane on deck to conduct the repair. The floating repair strategies assume that the turbines are in a vertical configuration as they travel to the inshore assemble area where components can be repaired or replaced in a sheltered environment. After the repair, the turbines are then towed back to their position within the project and reconnected to their respective moorings and power

⁵² O&M costs for floating projects will likely have some sensitivity to water depth due to different vessel and equipment requirements; however, enough information is not yet available to accurately quantify this relationship.

cables. A potential option for towing a spar substructure back to port for repair is towing it in a horizontal configuration. In this analysis, we assume a horizontal tow of a spar to be the same as the tow-to-port strategy used for the semisubmersible.

In practice, project sponsors optimize the spread of equipment used for a given project depending on its unique conditions: predominantly distance from O&M facilities and the metocean climate.⁵³ An optimized O&M strategy is one that simultaneously minimizes direct OpEx while maximizing the revenue that the project can generate through power sales (maximizing availability). NREL evaluates the efficacy of O&M strategies by comparing total O&M cost, which is defined as direct OpEx plus revenue losses. Revenue loss is a theoretical measure that captures the opportunity cost of revenue that could have been generated by the project if availability losses were equal to zero. This assessment values lost production at \$150/MWh to calculate revenue loss. Figure C-32 illustrates these optimization criteria by showing the relationship between OpEx and lost revenue and how analysts can identify the optimal O&M scenario through concurrent consideration of the variables.

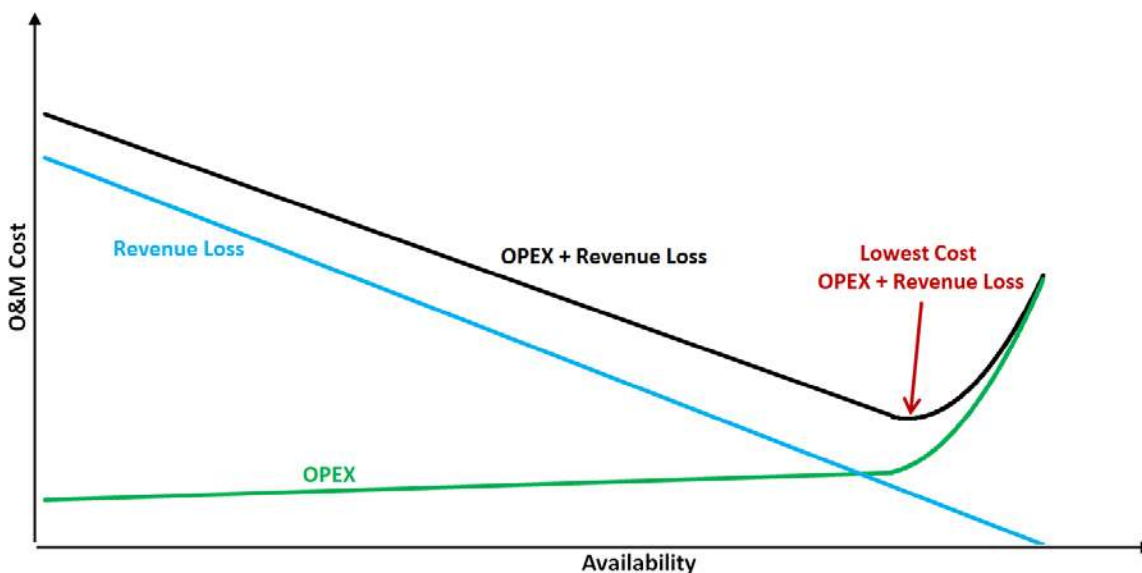


Figure C-32. Illustrative depiction of O&M optimization criteria

This spatio-economic assessment approximates this optimization exercise by considering several scenarios that vary the spread of vessels and equipment used to perform O&M activities within the broader in-situ and tow-to-shore approach to maintenance. The result of the analysis provides a matrix of outputs for OpEx and availability, and it allows for the identification of economic break points among the strategies at representative sites with different metocean conditions. Analysts evaluate this matrix to identify parametric curves that describe how OpEx and availability is likely to change with respect to spatial variables.

The OpEx analysis consists of several steps:

⁵³ Other considerations include project size, technology, local infrastructure availability, etc.; however, these are assumed constant in this assessment.

1. **Define O&M strategies.** There are several O&M strategies to consider as a wind power plant becomes farther from shore. This analysis focuses on four primary O&M strategies: (1) close to shore, (2) close to shore plus (+), (3) medium distance, and (4) far shore. The main differences among these strategies are related to the methods by which maintenance technicians are transported to and access turbines.
2. **Assess U.S. metocean conditions.** The ECN O&M tool requires inputs for wind and wave limitations on equipment utilized for O&M activities as well as time-series metocean data describing significant wave height and wind speed. Because time-series data sets are not available for every location in the U.S. technical resource area, NREL developed three sites for use in the O&M analysis that are broadly representative of the different U.S. metocean conditions: mild, moderate, and severe.
3. **Collect and format time-series data.** Analysts gathered and processed time-series wind and wave data from the three representative wave information system (WIS) stations to create an input deck for the ECN O&M tool (i.e., 10 years of correlated wind and wave data at hourly intervals).
4. **Specify O&M modeling assumptions.** Analysts gathered European offshore wind data and collaborated with the offshore wind industry to develop modeling assumptions that describe each of the four O&M strategies (i.e., close to shore, close to shore (+), medium distance, and far shore).
5. **Run the ECN model.** Analysts evaluated each of the O&M strategies for distances between the project and the O&M port ranging from 10 km–500 km for each of the three representative sites. In total, analysts ran 36 scenarios. The ECN O&M tool (Microsoft Excel-based) was able to complete one run in approximately 8 hours.
6. **Compare results.** The primary outputs of the O&M tool are OpEx, availability, and total O&M cost (OpEx + revenue loss). Analysts evaluated the total O&M cost results to identify economic break points among O&M strategies for each of the three representative sites.
7. **Develop OpEx and availability equations.** After identifying the low-cost O&M strategy at each distance, analysts then disaggregated results into their constituent parts to determine how OpEx and availability might realistically change with distance to port, assuming adoption of the optimal O&M strategy at each distance. Analysts then fit curves to the OpEx and availability results to describe the relationship among OpEx, availability, and relevant spatial parameters (logistical distances and metocean conditions).

O&M Strategies

The four O&M strategies selected for this analysis define the means by which technicians access the turbines and other project elements to perform maintenance. NREL defined the maintenance strategies based on strategies that have been implemented or are being considered by the offshore wind industry. Because this analysis covers a wide range of potential site locations that extend beyond current industry experience, several of the strategies rely on vessel concepts that are still in the proof-of-concept phase, wherein the vessel is either undergoing sea trials, under construction, or even still on the drawing board. Many of the vessel concepts and access technologies have been supported by the Carbon Trust's Offshore Wind Accelerator Access Competition (Carbon Trust 2011). A high-level description of each of the O&M strategies is

shown in Table C-22. Note that this analysis assumes that all vessels are chartered and that no capital investment is required.

Table C-22. Matrix of O&M Strategies

	Close to Shore	Close to Shore+	Medium Distance	Far Shore
Alias	CS	CS+	MD	FS
Description	Standard port-based O&M strategy	Standard port-based O&M strategy	Enhanced port-based O&M strategy	Mothership-based O&M strategy
Principle Access Vessel	Basic CTV ^a	Advanced CTV	SES ^b	CTV with mothership support
Wind Limit (m/s)	20	20	20	20
Hs Limit (m)	1.5	2.3	2.5	2.5
Vessel Speed (kn)	20	20	35	20
Access Vessel Day Rate	\$2,800 ^c	\$6,500 ^c	\$9,000 ^c	\$2,800 ^c
Passengers (#)	12	12	12	12
Shift Length (h)	12	12	12	12
Docking and Transfer Time (h)	0.5	0.5	0.5	1.0
Fuel Consumption Rate (gal/h):	25	25	20	25
Fixed Annual Maintenance Costs	n/a	n/a	n/a	\$18,000,000 ^d
Capital Investment	n/a	n/a	n/a	n/a

^a Crew transfer vessel

^b Surface effect ship

^c ECN User Guide.

^d Communications with offshore wind industry.

Note: All other O&M equipment assumptions are from offshore wind industry feedback and NREL's offshore wind database.

Close-to-Shore Strategy

The close-to-shore strategy is typical of many offshore wind power plants operating today in Europe. It uses a standard CTV, which transfers personnel using a step-off method. This strategy carries a limitation for transfers of 1.5m Hs. The close-to-shore strategy has a maximum range of approximately 70 km in this assessment, or approximately 2 hours (one way) of traveling time between the project and O&M port at the CTV's cruising speed (20 kn). This limitation considers seasickness and wear and tear on the technicians as they travel to and from the wind site. The close-to-shore strategy is modeled only for the mild metocean site; initial model runs

demonstrated that this strategy is not feasible in the moderate or severe sites. All other O&M equipment assumptions, depending on the substructure technology, remain the same.

Close-to-Shore (+) Strategy

The close-to-shore (+) strategy relies on advanced CTWs that are beginning to be commercialized. These vessels are characterized by relaxed limitations for technician transport, making them more suitable for sites with challenging metocean regimes; hence, this strategy was considered as an alternative to the close-to-shore strategy at the moderate and severe metocean sites. For example, the Fjellstrand WindServer incorporates roll plates and ballast tanks to dampen the pitch motions of the vessel, and this enables the transfer of technicians in sea states of up to 2.3 m Hs.

The primary differences between the close-to-shore and close-to-shore (+) strategy are the increase in transport vessel wave limitation from 1.5 m–2.3 m as well as an increase in vessel day rate (\$6,500/day). The close-to-shore (+) strategy assumes that the CTV travels at the same speed as the standard CTV; therefore, the same maximum distance to O&M port applies (i.e., 70 km), limiting the maximum transport time to 2 hours. All other O&M equipment assumptions, depending on the substructure technology, remain the same.

Medium-Distance Strategy

The medium-distance strategy considers a new generation CTV known as a surface effect ship (SES). The SES vessel has an increased transport speed and wave limitation that makes it suitable for sites that are both farther from shore and have more challenging metocean conditions. The SES provides a substitute to O&M strategies such as helicopter access, which may not be a preferred solution for floating offshore wind turbines. The model assumes a SES based on the UMOE Wave Craft (see Figure C-33), which DONG Energy has chartered for testing at Borkum Riffgrund 1, located 54 km from DONG Energy's O&M base in Norddeich (DONG Energy 2014).

In this assessment, the SES has a maximum range of 150 km from the O&M port, assuming a 2-hour limit (one way) for transport time. NREL assumes the SES has a personnel transfer limit of 2.5 m Hs and a day rate of \$9,000. All other O&M equipment assumptions, depending on the substructure technology, remain the same.



Figure C-33. Illustration of the UMOE Mandal AS Wave Craft. *Image from UMOE 2013*

Far-Shore Strategy

The far-shore strategy considers a mothership vessel that acts as a hotel vessel for maintenance personnel. Additional capabilities of the mothership include CTV launch and an onboard warehouse to store equipment and small spare parts. The sustained endurance of the vessel is estimated to be in the range of 1–2 months before it returns to port for resupply. The Esvagt service operation vessel is a mothership that is about to enter into commercial service (see Figure C-34). These motherships will support Siemens maintenance activities at the 288-MW Butendiek and the 288-MW Baltic II projects in Germany (2015) and at Statoil’s 400-MW Dudgeon project in the UK (2016) (ESVAGT 2014).



Figure C-34. Illustration of ESVAGT service operation vessel mothership. *Image from ESVAGT 2014*

The ECN O&M tool must be modified to model the role of the mothership in the far-shore strategy. The mothership effectively serves as the O&M port for all O&M activities except for major component replacements and BOS repair. NREL therefore assumes that the distance from port for these inspection and repair categories is 10 km, which represents the maximum distance that CTWs may have to travel from the mothership to turbines. The mothership is also equipped

with a heave-compensated gangway (similar to the Ampelmann) that enables it to transport technicians to the turbines for repair in parallel with CTV operations in mild weather and also when poor weather conditions prevent transfers via CTWs. All other O&M equipment assumptions, depending on the substructure technology, remain the same.

Major Corrective Maintenance Strategies

The main difference between the operations of fixed and floating turbines is in the approach to correction major up-tower failures. This analysis considers three corrective maintenance strategies to represent the five substructure scenarios:

- **In situ** (monopile and jacket substructures): maintenance is performed at the project location by a jack-up crane vessel
- **Tow to port** (semisubmersible and spar horizontal tow): the substructure-turbine unit is disconnected from the moorings and towed to port for repair by a crawler crane at port side
- **Tow to assembly area** (spar vertical tow): the substructure-turbine unit is disconnected from the moorings and towed to the inshore assembly site; this requires the mobilization of the installation equipment spread (e.g., barge and crane).

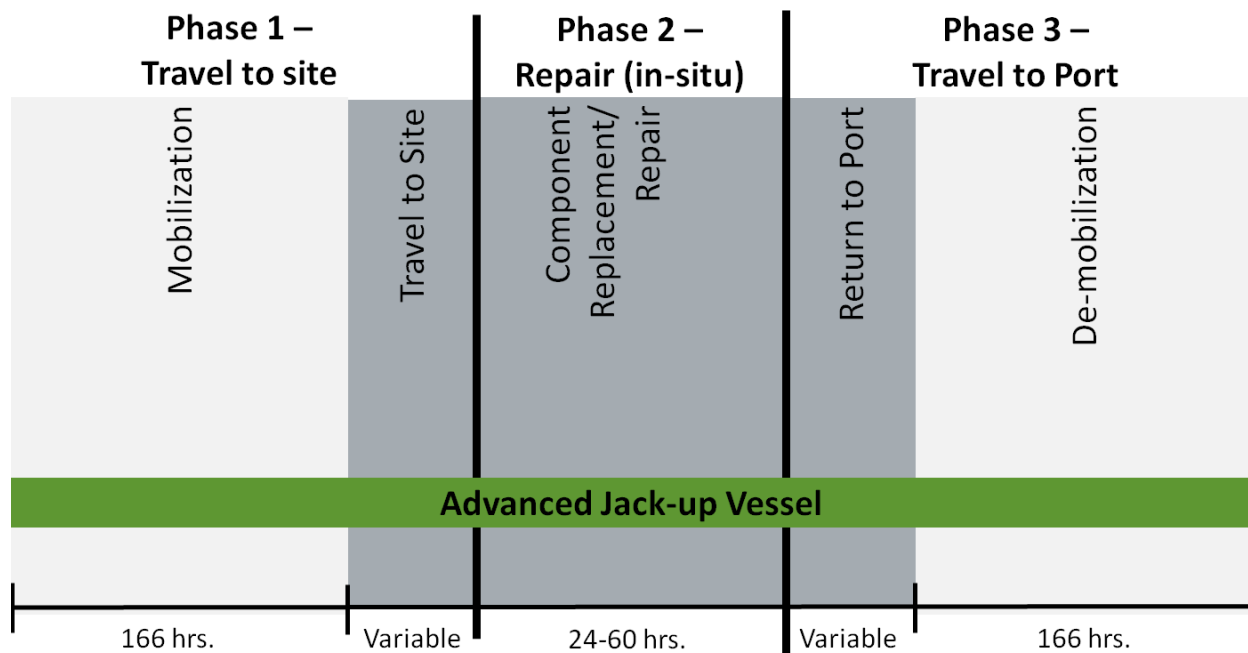


Figure C-35. In situ major corrective strategy illustration

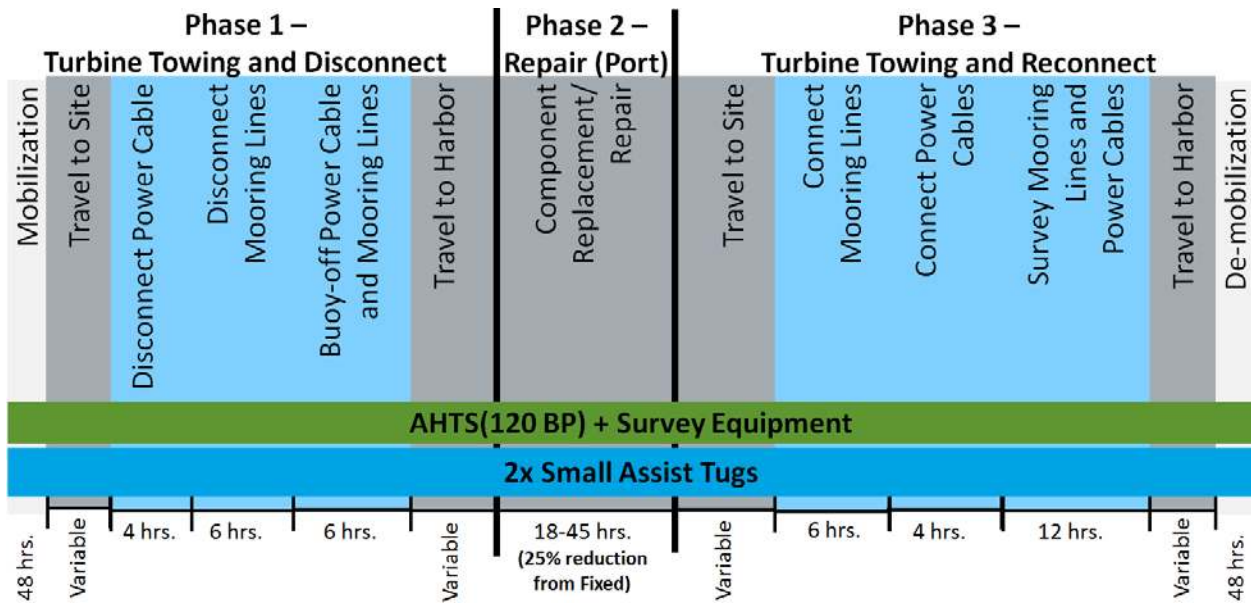


Figure C-36. Tow-to-port major corrective strategy illustration

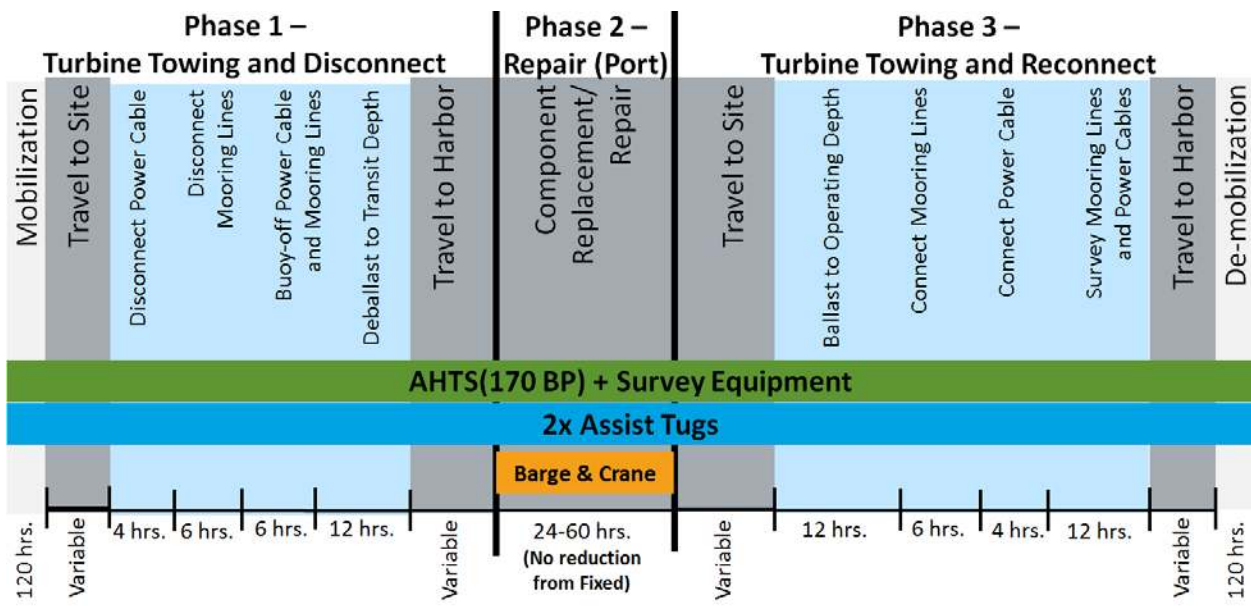


Figure C-37. Tow-to-assembly area major corrective strategy

Metocean Categories

Significant wave height and prevailing wind speed are the key factors that limit the ability of O&M technicians to access turbines and perform O&M activities.⁵⁴ Metocean conditions vary widely among potential offshore wind sites in the United States (see Figure 11), which can have significant impacts on OpEx and availability.

⁵⁴ Other factors, including wave period, wave direction, currents, tides, and visibility, can also impact availability, but they are not considered in this analysis.

The ECN O&M tool is reconfigured for each set of metocean conditions before sensitivities can be evaluated. Although an assessment of the location-specific costs would ideally consider metocean conditions at individual sites, NREL determined that this approach would not be feasible due to the immense amount of data processing and ECN O&M tool runs it would entail. Instead, NREL analyzed a joint distribution of annual average wind speeds and wave heights from the MHK Atlas and identified three distinct local maxima. Analysts then identified WIS stations that most closely match the local maxima to serve as representative sites for the O&M analysis. Figure 28 shows the three sites that represent mild, moderate, and severe metocean climates as well as how individual potential offshore wind power project locations are assigned metocean categories. Table C-23 summarizes the details of each WIS station. Appendix B describes the approach for identifying representative sites and categorizing sites in greater detail.

Table C-23. Details for Representative Wave Sites

Name	WIS Buoy ID	Location Description	Latitude (Lat.), Longitude (Long.)	Average Significant Wave Height (m)	Average Wind Speed @ 10-m Elevation (m/s)
Mild	73075	SE of Galveston, TX	Lat. 28.950, Long. -94.500	0.88	6.12
Moderate	63080	SE of Nantucket, MA	Lat. 41.170, Long. -69.670	1.39	7.32
Severe	83038	SW of Gold Beach, OR	Lat. 42.330, Long. -124.670	2.50	6.61

Analysts used the three WIS stations to generate correlated time-series data describing wind and wave at each site (1-hour increments covering the 10-year period). These data are input into the ECN O&M tool and form the basis for the O&M analysis.

C.2.4.2 O&M Parameter Study

NREL defined a parameter study to investigate how OpEx and availability change with respect to metocean conditions, distance to shore, and O&M strategy. Table C-24 illustrates the matrix of O&M scenarios run for the analysis. Details on each of the strategies are presented in Section 6.

Table C-24. Matrix of OpEx Modeling Parameters

		Metocean Conditions								
		Mild Site Mean Hs = 0.89 m Mean Ws = 6.12 m/s			Moderate Site Mean Hs = 1.39 m Mean Ws = 7.32 m/s			Severe Site Mean Hs = 2.50 m Mean Ws = 6.61 m/s		
Distance to O&M Port	10 km	CS	MD	FS	CS+	MD	FS	CS+	MD	FS
	30 km	CS	MD	FS	CS+	MD	FS	CS+	MD	FS
	50 km	CS	MD	FS	CS+	MD	FS	CS+	MD	FS
	70 km	CS	MD	FS	CS+	MD	FS	CS+	MD	FS
	90 km	***	MD	FS	***	MD	FS	***	MD	FS
	110 km	***	MD	FS	***	MD	FS	***	MD	FS
	150 km	***	MD	FS	***	MD	FS	***	MD	FS
	200 km	***	***	FS	***	***	FS	***	***	FS
	300 km	***	***	FS	***	***	FS	***	***	FS
	400 km	***	***	FS	***	***	FS	***	***	FS
	500 km	***	***	FS	***	***	FS	***	***	FS

Note: CS = close to shore; CS+ = advanced close to shore; MD = medium distance; FS = far shore.

*** Distance exceeds 2-hour limit for transporting technicians between the O&M port and the project.

The parameter study results are evaluated based on total O&M cost, which includes two parameters: (1) OpEx and (2) lost revenue. The lowest cost strategy is identified based on the minimum total O&M cost at each distance from O&M for each representative metocean site. Analysts then disaggregated results into their constituent parts to determine how OpEx and availability might realistically change with distance to port, assuming the adoption of the optimal O&M strategy.

The parameter study considers the distance from O&M port to project site for the 36 ECN model runs; however, large turbine repairs assume that the turbine is towed back to the port for floating substructures, the semisubmersible is towed to the O&M port, and the spar is towed to the project's assembly port. Considering the variability of the distance between the site and project assembly area for the spar would add another dimension to the parameter study matrix and would create an unrealistic number of model runs given the processing time. Distance from the project site to the assembly area is also not anticipated to be a large driver of O&M cost for the following two reasons: (1) the only parameter that changes is the towing time, which will grow linearly with distance, and (2) the vertical tow operation is fairly insensitive to weather conditions, with nonexceedance limits of 4.5 m Hs and wind speed of 20 m/s. The spar's vertical tow operation is modeled independently from the turbine access strategy because these operations have different governing metocean limits.

Instead of considering the variable distance between project and assembly area within the O&M parameter study matrix, NREL investigated the impact of this variable separately for one O&M scenario (medium-distance strategy in moderate metocean site) while holding distance to port constant. This study showed that OpEx costs increased linearly with distance between project and the inshore assembly area and that availability was unaffected. This variable impact is captured by a linear cost premium that modifies the OpEx that is calculated as a function of distance from the project to O&M port and metocean conditions.

C.2.4.3 O&M Parameter Study Results

The O&M parameter study yields results for both OpEx and availability covering the matrix of cases. Analysts calculate revenue loss from availability losses and value it at an opportunity cost of \$150/MWh. Analysts then aggregate OpEx and revenue losses to compare the efficacy of the O&M strategies for the fixed and floating substructures in the three representative sites as summarized in this section.

Although each of the representative sites has a similar trend, wherein OpEx increases with distance from O&M port, the severe site has a significantly higher OpEx than the mild and moderate sites. The harsh metocean conditions at the severe site drive the cost of turbine and BOS repairs. Operable weather windows, dictated by the vessel spread capabilities, are few and far between. This means that charter vessels often sit idle at the port waiting for favorable weather and charging day rates. NREL recommends that further investigation be conducted on O&M strategies that could be effective in sites located in challenging metocean environments.

The curve fits of the results are used to estimate the availability in the Offshore Wind LCOE Cost Estimation Spreadsheet. Although each of the representative sites has a similar trend for availability with increased distance from O&M port, the severe site has a significantly lower availability than the mild and moderate sites. The harsh metocean conditions of the severe site highly impact availability by exceeding some of the O&M equipment limitations. Further sensitivity studies are recommended to better understand the factors driving the low availability for the severe site.

Fixed-Bottom

Mild Site

Figure C-38 shows results for the fixed-bottom substructure in the mild site.

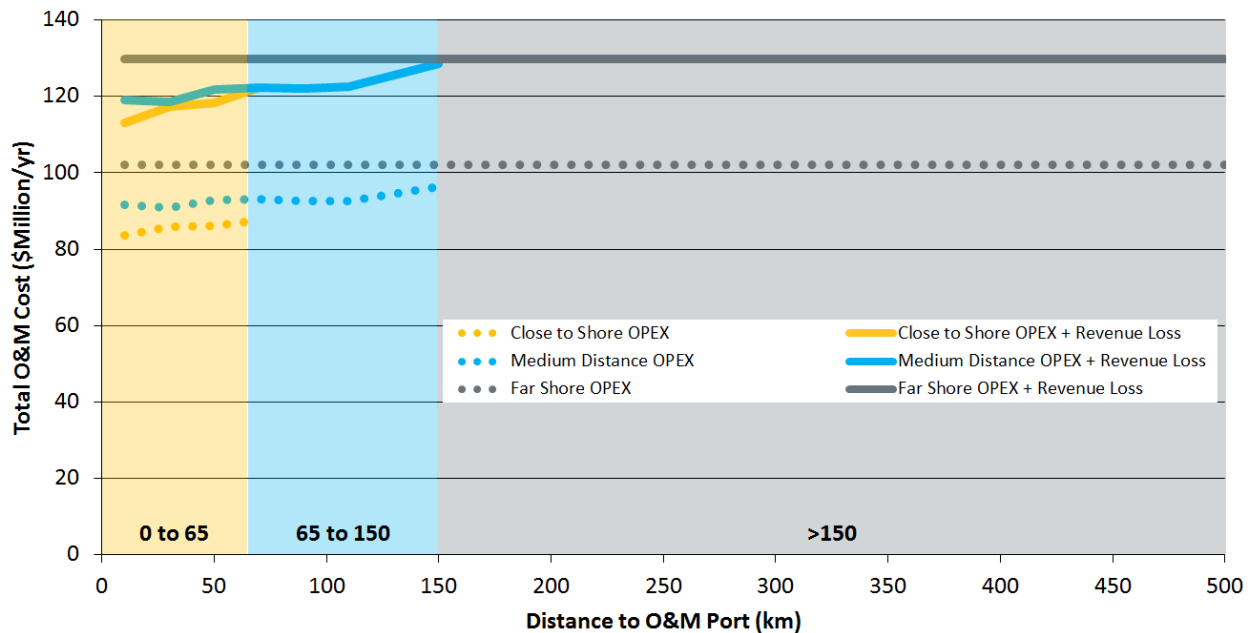


Figure C-38. Mild site total O&M cost for fixed-bottom substructure

The economic break points among O&M strategies are as follows:

- Close-to-shore strategy: distance to O&M port ≤ 65 km
- Medium-distance strategy: $65 \text{ km} < \text{distance to O\&M port} < 150 \text{ km}$
- Far-shore strategy: $150 \text{ km} < \text{distance to O\&M port}$.

The assumed 2-hour limit on transportation time drives the break points among strategies at the mild site for the fixed-bottom substructure.

Moderate Site

Figure C-39 shows results for the moderate site.

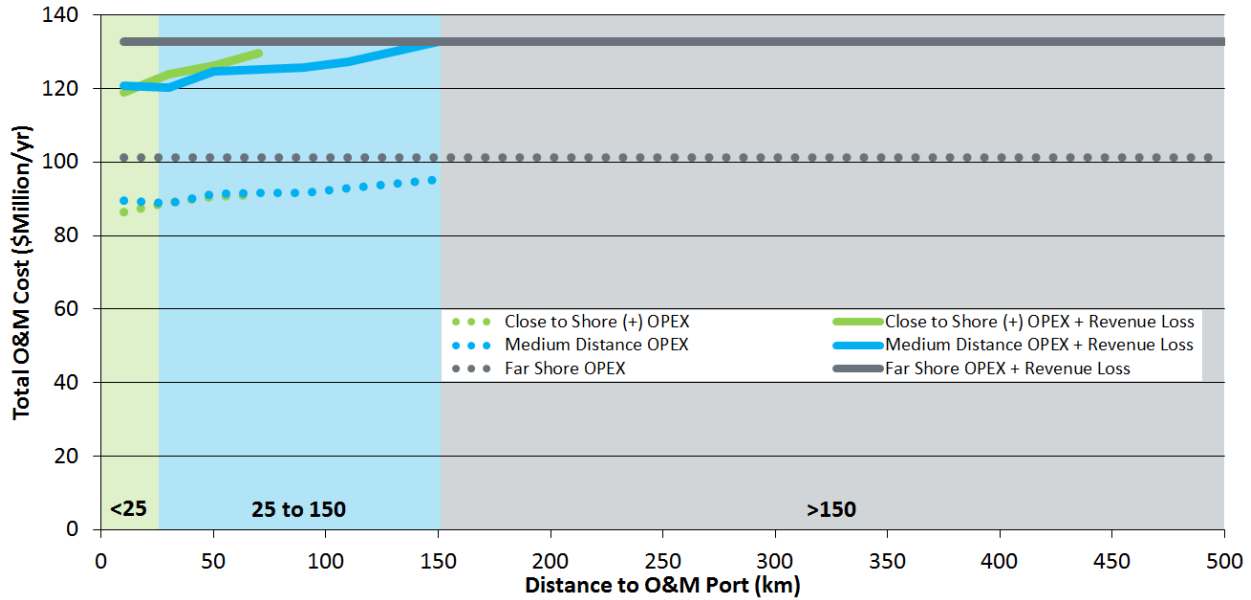


Figure C-39. Moderate site total O&M cost for fixed-bottom substructure

The economic break points among O&M strategies are as follows:

- Close-to-shore (+) strategy: distance to O&M port ≤ 25 km
- Medium-distance strategy: $25 \text{ km} < \text{distance to O\&M port} < 150 \text{ km}$
- Far-shore strategy: $150 \text{ km} < \text{distance to O\&M port}$.

The moderate site does not consider the close-to-shore strategy because the metocean conditions are not ideal for this strategy. The O&M cost drives the break point between the close-to-shore (+) strategy and medium-distance strategy, whereas the transport time restriction of 2 hours drives the break point between the medium-distance and far-shore strategies.

Severe Site

Figure C-40 shows results for the severe site.

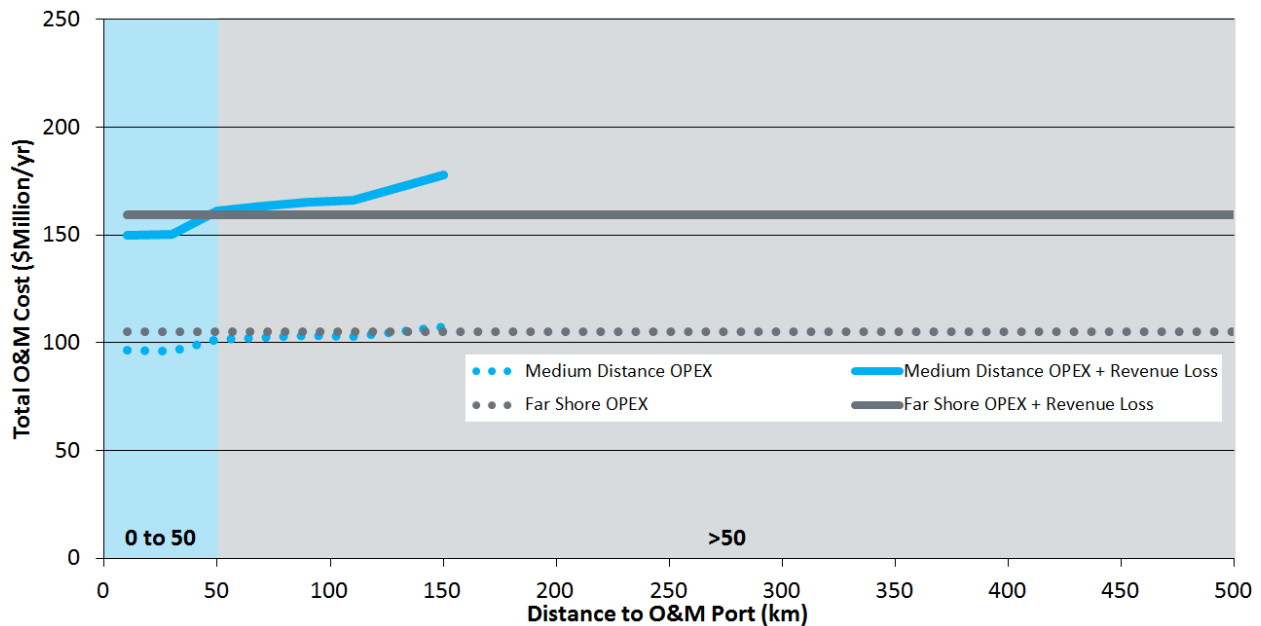


Figure C-40. Severe site total O&M cost for fixed-bottom substructure

The O&M strategy break points determined by the lowest cost O&M strategy for the severe site are:

- Medium-distance strategy: distance to O&M port $< \approx 50$ km
- Far-shore strategy: ≈ 50 km $<$ distance to O&M port.

The close-to-shore (+) strategy is never the cost-effective O&M strategy for the severe site. The cost of O&M drives the break points between the medium-distance and far-shore strategies.

Figures C-38–C-40 show the disaggregated OpEx and availability curves in the mild, moderate, and severe sites for the fixed-bottom substructure.

Although each of the representative sites has a similar trend, where OpEx increases with distance from O&M port, the severe site has a significantly higher OpEx than the mild and moderate sites.

Spar

Mild Site

Figure C-41 shows results for the spar in the mild site.

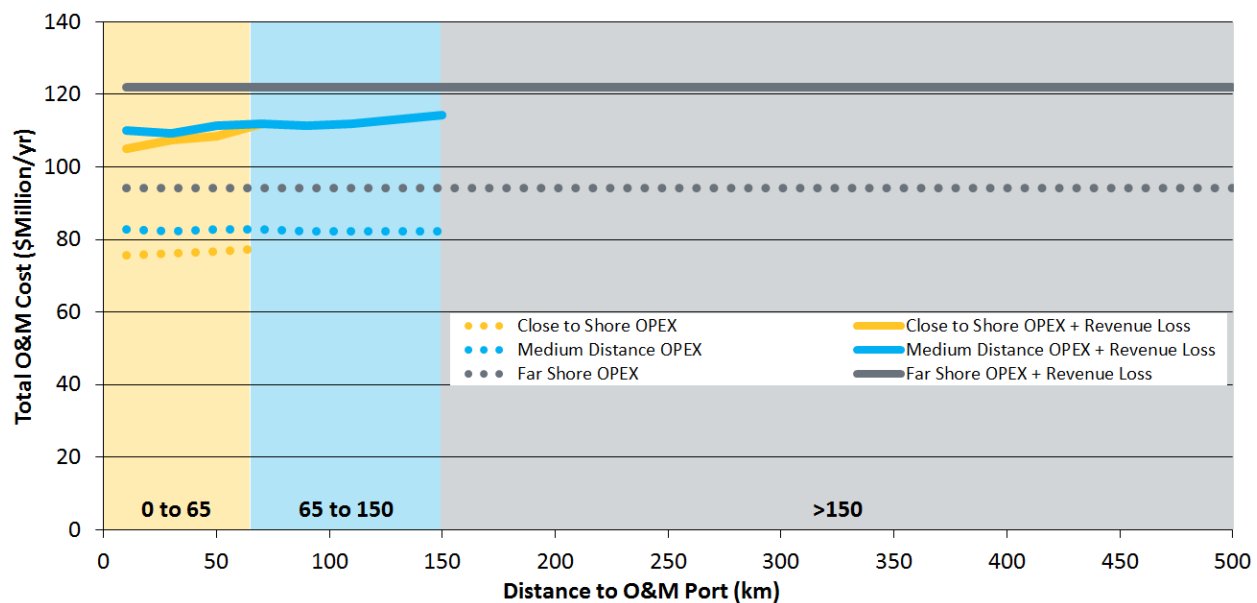


Figure C-41. Mild site total O&M cost for spar substructure

The economic break points among O&M strategies are as follows:

- Close-to-shore strategy: distance to O&M port < ≈ 65 km
- Medium-distance strategy: ≈ 65 km < distance to O&M port < ≈ 150 km
- Far-shore strategy: ≈ 150 km < distance to O&M port.

The assumed 2-hour limit on transportation time drives the break points among strategies at the mild site for the spar substructure.

Moderate Site

Figure C-42 shows results for the moderate site.

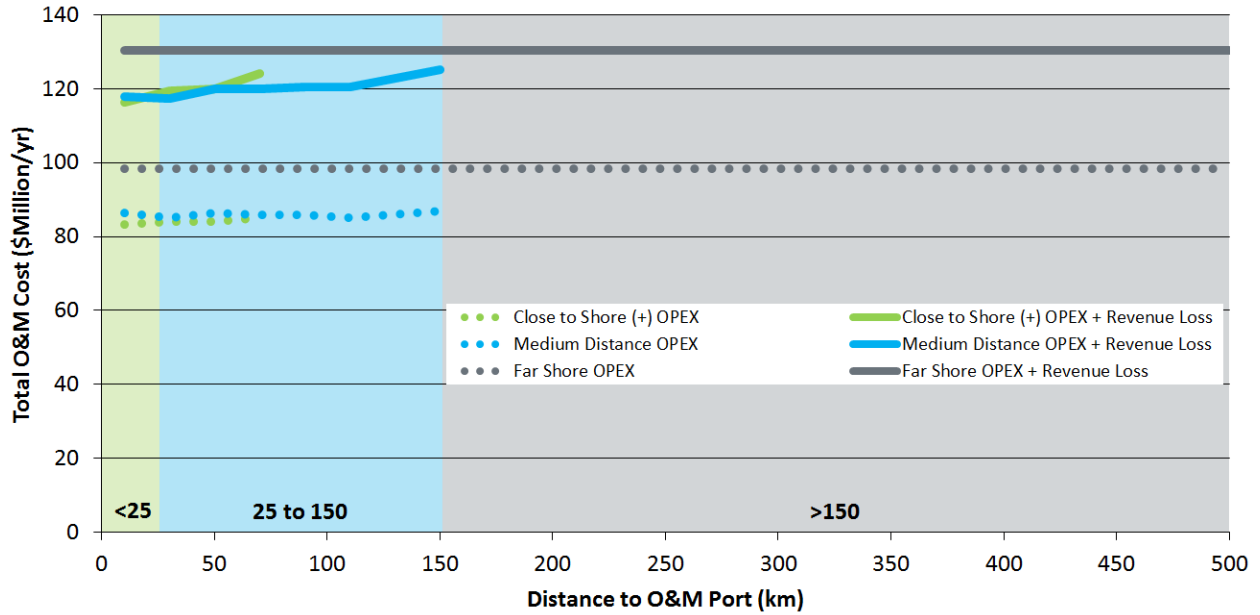


Figure C-42. Moderate site total O&M cost for spar substructure

The economic break points among O&M strategies are as follows:

- Close-to-shore (+) strategy: distance to O&M port < ≈ 25 km
- Medium-distance strategy: ≈ 25 km < distance to O&M port < ≈ 150 km
- Far-shore strategy: ≈ 150 km < distance to O&M port.

The moderate site does not consider the close-to-shore strategy because the metocean conditions are not ideal for this strategy. The O&M cost drives the break point between the close-to-shore (+) strategy and medium-distance strategy, whereas the transport time restriction of 2 hours drives the break point between the medium-distance and far-shore strategies.

Severe Site

Figure C-43 shows the results for the severe site.

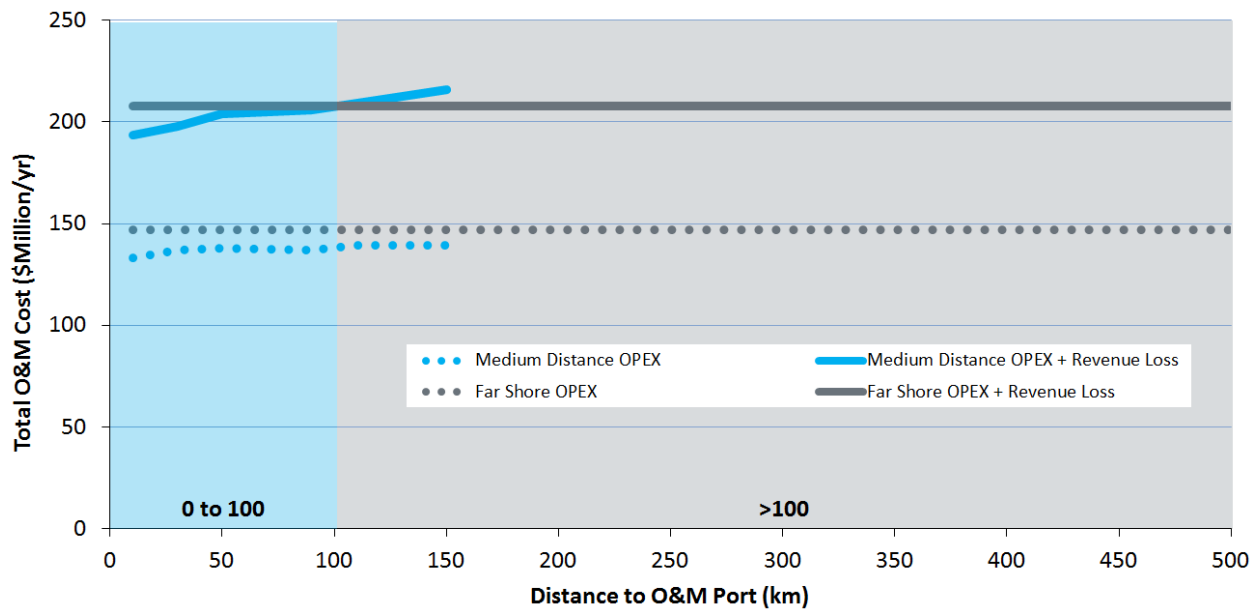


Figure C-43. Severe site total O&M cost for spar substructure

The O&M strategy break points determined by the lowest cost O&M strategy for the severe site are:

- Medium-distance strategy: distance to O&M port $< \approx 100$ km
- Far-shore strategy: ≈ 100 km $<$ distance to O&M port.

The close-to-shore (+) strategy is never the cost-effective O&M strategy for the severe site. The cost of O&M drives the break points between the medium-distance and far-shore strategies.

Figure C-43 show the disaggregated OpEx and availability curves in the mild, moderate, and severe sites for the spar substructure.

Semisubmersible

Mild Site

Figure C-44 shows results for the semisubmersible in the mild site.

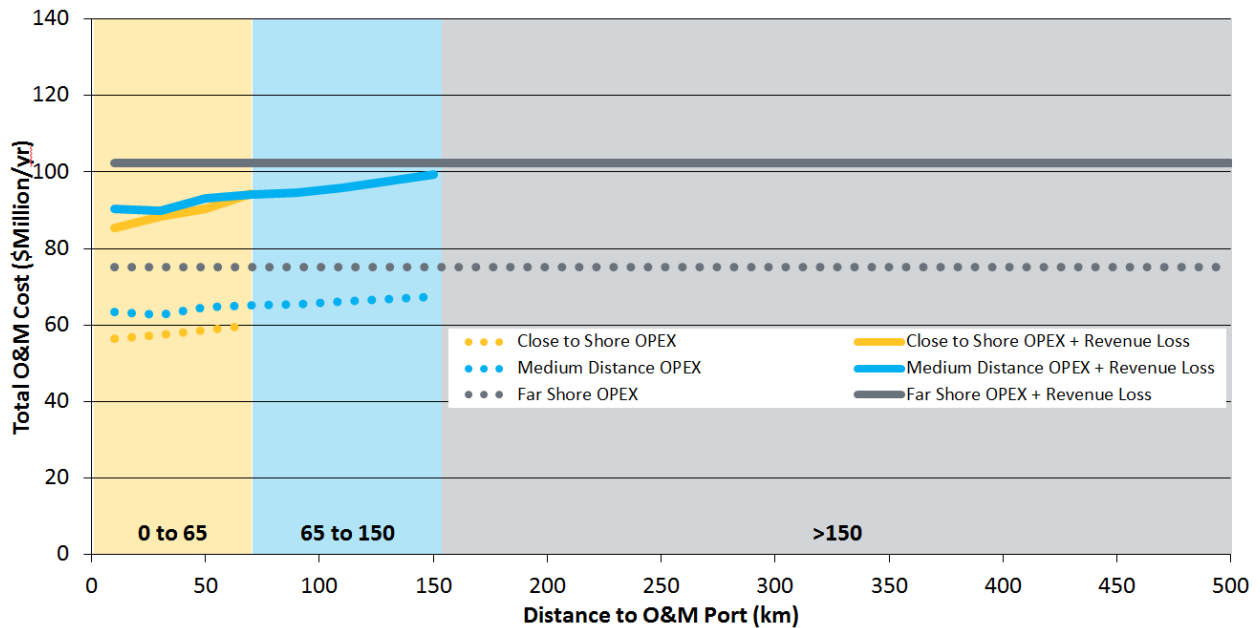


Figure C-44. Mild site total O&M cost for semisubmersible substructure

The economic break points among O&M strategy are as follows:

- Close-to-shore strategy: distance to O&M port < ≈ 65 km
- Medium-distance strategy: ≈ 65 km < distance to O&M port < ≈ 150 km
- Far-shore strategy: ≈ 150 km < distance to O&M port.

The assumed 2-hour limit on transportation time drives the break points among strategies at the mild site for the spar substructure.

Moderate Site

Figure C-45 shows results for the moderate site.

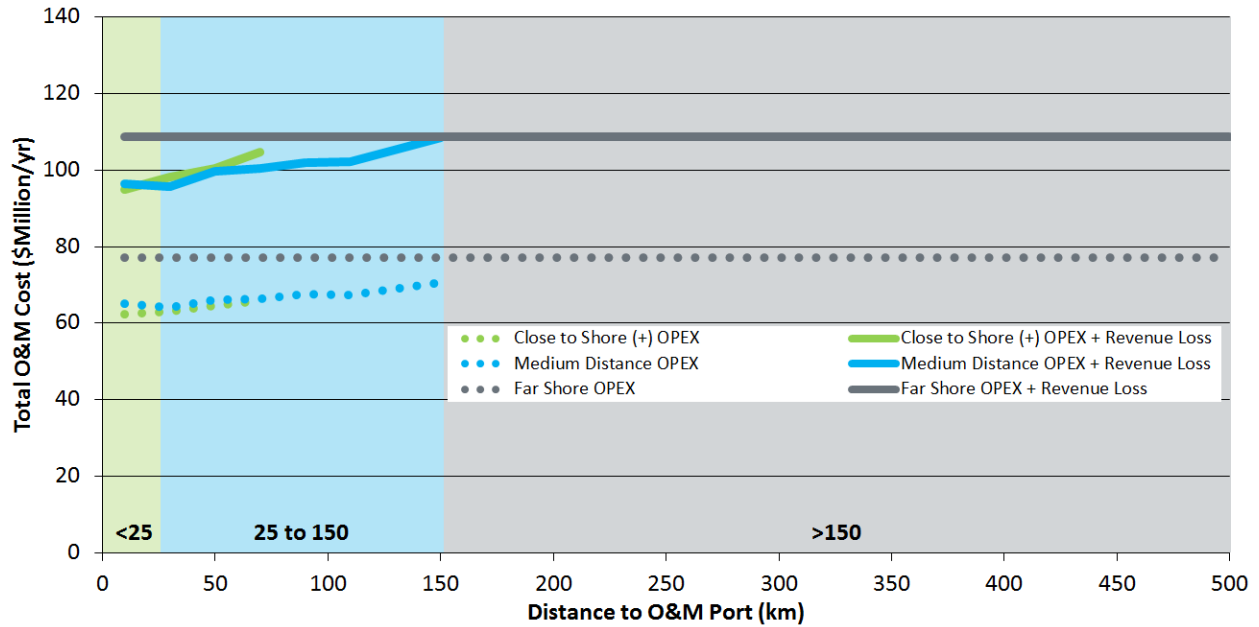


Figure C-45. Moderate site total O&M cost for semisubmersible substructure

The economic break points among O&M strategies are as follows:

- Close-to-shore (+) strategy: distance to O&M port $< \approx 25$ km
- Medium-distance strategy: ≈ 25 km $<$ distance to O&M port $< \approx 150$ km
- Far-shore strategy: ≈ 150 km $<$ distance to O&M port.

The moderate site does not consider the close-to-shore strategy because the metocean conditions are not ideal for this strategy. The O&M cost drives the break point between the close-to-shore (+) strategy and medium-distance strategy, whereas the transport time restriction of 2 hours drives the break point between the medium-distance and far-shore strategies.

Severe Site

Figure C-46 shows results for the severe site.

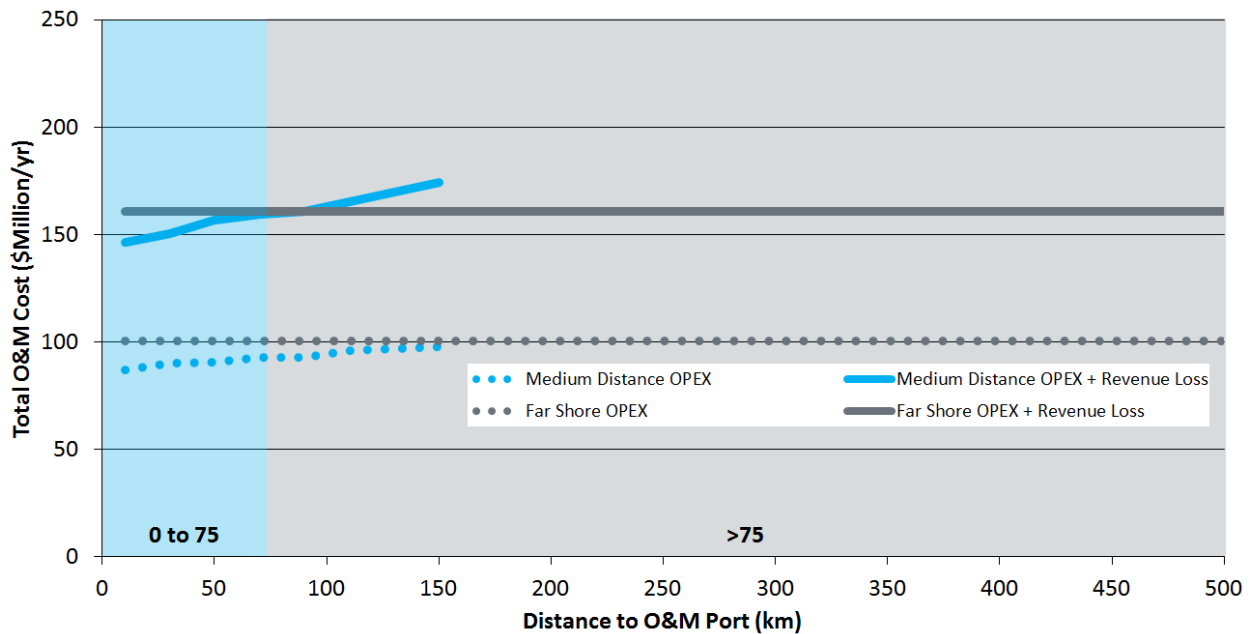


Figure C-46. Severe site total O&M cost for semisubmersible substructure

The O&M strategy break points determined by the lowest cost O&M strategy for the severe site are:

- Medium-distance strategy: distance to O&M port < ≈ 75 km
- Far-shore strategy: ≈ 75 km < distance to O&M port.

The close-to-shore (+) strategy is never the cost-effective O&M strategy for the severe site. The cost of O&M drives the break points between the medium-distance and far-shore strategies

Figure C-45 and Figure C-46 show the disaggregated OpEx and availability curves in the mild, moderate, and severe sites for the semisubmersible substructure.

C.2.4.4 Spar Horizontal-Tow Scenario

A horizontal-tow scenario for the spar is considered in this analysis as an alternative to the vertical-tow scenario for the spar. Given the level of effort to run the ECN model, the horizontal-tow analysis was simplified to be a sensitivity study to roughly approximate the cost impacts of using a horizontal-tow strategy to the project’s O&M port instead of a vertical-tow scenario to the project’s assembly port. This was achieved by utilizing already-run ECN models for the moderate site using a medium-distance O&M strategy for distances to O&M port ranging from 0 km–200 km (assuming the same maximum 10-day tow limit as the vertical-tow scenarios). For the range of distances from O&M port, it was assumed there no inshore assembly equipment (estimated at \$13.4M annually) is required, and all major repairs were performed at the O&M port. Additionally, there were no changes to the optimal O&M strategy at each model run distance (i.e., all access limits remain the same).

NREL assumes that the horizontal transport vessel is capitalized or owned by the project so there is no charge to the project; however, operating costs specific to the horizontal-tow vessel are not captured, and no change to the vessel spread is assumed for towing. The vessel spread assumption may be updated once the horizontal-tow strategy is more fully understood and specified. The availability was essentially unaffected due to the assumption that the horizontal-tow is fairly insensitive to weather conditions (modeled such that transport activities have nonexceedence of 4.5 m and 20 m/s), which is likely optimistic.

In general the O&M cost for any distance from O&M was reduced by \$13.4M using this simplified modeling approach. This reflects the average cost to mobilize the inshore assembly area each year. The cost reduction was applied to the O&M cost estimate in the Offshore Wind LCOE Cost Estimation Spreadsheet for the horizontal-tow strategy.

C.3 Levelized Avoided Cost of Energy

The levelized avoided cost of energy (LACE) metric, introduced by the Energy Information Administration (EIA), approximates what it would cost to generate the electricity that is otherwise displaced by a new generation project (EIA 2015b; Namovicz 2013; EIA 2013). It captures two revenue sources: marginal generation price and capacity value.⁵⁵ Similar to the LCOE calculation, we approximate the discounted cash flow through the use of annualized values that are representative of lifetime⁵⁶ averages. There are multiple ways to calculate available revenue to generation sources and various terms (e.g., market value) that are in use (see Massachusetts Institute of Technology [2015]; Hirth [2013]). For this analysis, we applied a methodology adapted from EIA (Namovicz 2013; EIA 2013), which offers the following general equation:

$$\text{LACE} = \frac{MP * AEP_{net} + CP * CC}{AEP_{net}} \quad (3)$$

where:

- MP = marginal generation price (\$/MWh)
- AEP_{net} = net annual energy production (MWh/yr)
- CP = capacity payment (\$/kW/yr)
- CC = capacity credit (%)

Marginal generation price captures the marginal value of energy, which is multiplied by the net annual energy production (AEP_{net}) to yield the annual revenue from electricity production. The product of capacity payment (CP) and capacity credit (CC) yields the marginal value of capacity. For the purpose of this study, marginal generation price was represented by either locational marginal prices or market marginal costs (system lambdas) depending on data availability, which differed by region. The marginal generation price component of this approach takes into account projected electricity price increases throughout the lifetime of a renewable generation plant based

⁵⁵ These two LACE components, marginal generation price and capacity value, were applied to any electricity market found across U.S. coastal regions, regardless of the type of electricity market (e.g., energy-only-markets vs. capacity markets)

⁵⁶ In this analysis, 20 years were assumed for offshore wind project lifetime.

on the EIA's *Annual Energy Outlook 2015 with Projections to 2040* (2014) reference case price projections levelized to an effective present price. A capacity credit of 25% was assumed for offshore wind in this assessment based on land-based wind capacity credit estimates from Milligan and Porter (2008) because of the limited regional data for offshore wind at this point. Capacity payment is based on the overnight capital cost of a new advanced natural gas combustion turbine plant (EIA 2015a, Table 8.2). The calculation of AEP for LCOE and LACE is identical (see above). More details on the calculation of LACE are described in Brown et al. (2015).

As a result of data limitations, the resolution of LACE is smaller than those for LCOE. LACE was estimated for any year between 2015 (COD) and 2030 (COD). LACE is generally predicted to increase gradually among U.S. coastal areas over time as a result of increased power generation and delivery costs (EIA 2015a).⁵⁷ These increases in LACE vary by region. For an illustration of the spatial variation in LACE, Figure C-47 shows LACE estimates among U.S. coastal regions in 2025 (COD). The highest LACE can be found in the northeastern Atlantic coast due to relatively high electricity prices in that area. Moderate LACE can generally be found on the West Coast, and relatively low LACE can be found in the Southeast, Gulf Coast, and parts of the northern Great Lake areas and Northern California.

⁵⁷ Although EIA (2015a) and other sources generally predict an increase in power generation and electricity delivery costs, a range of factors may influence future electricity costs, of which some are challenging to predict. These may include (but are not limited to) future developments in the energy efficiency, transportation, and storage sectors; changes in fuel prices and generation technologies; market structures; and macroeconomic factors.

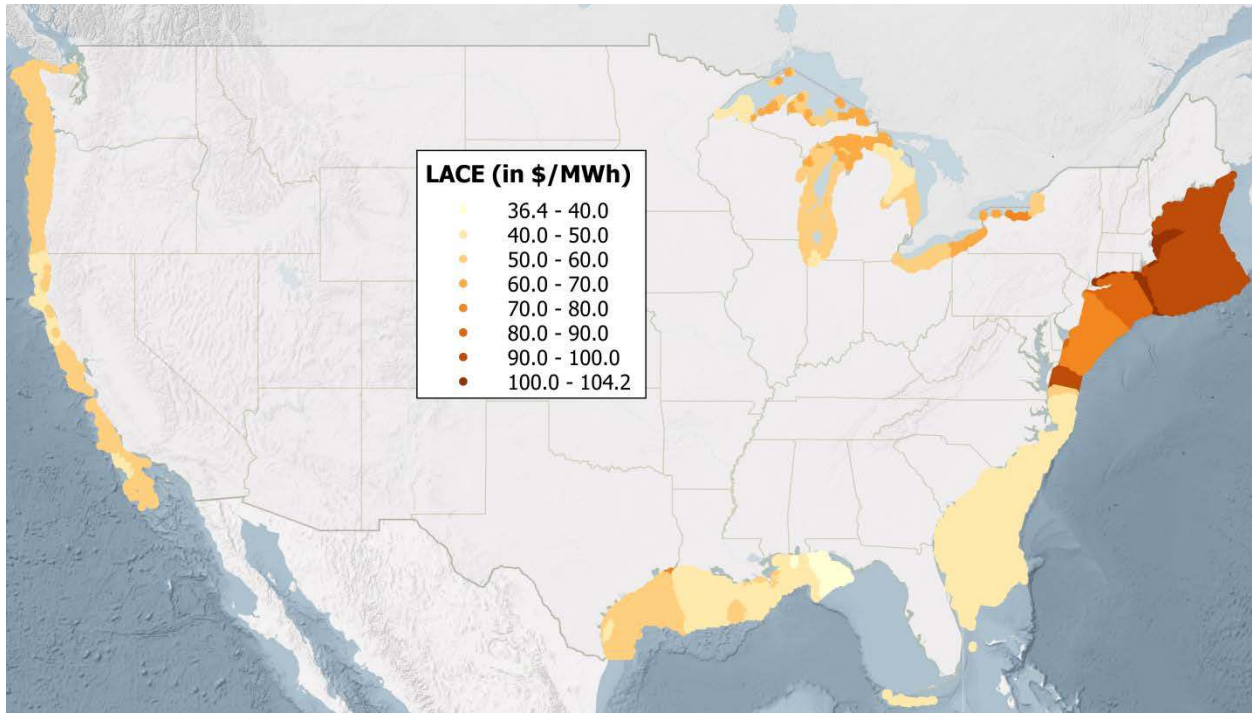


Figure C-47. LACE (unsubsidized⁵⁸) estimates for 2025 (COD)

Note: The LACE analysis comprises a preliminary assessment limited by available data and a set of simplifying assumptions. Hawaii is not included in this figure due to data limitations.

⁵⁸ Without considering any potential impacts from policy (e.g., state renewable portfolio standards, production tax credits, carbon pollution and other greenhouse gas regulation, or loan guarantee programs); Accelerated depreciation (MACRS) is considered.