
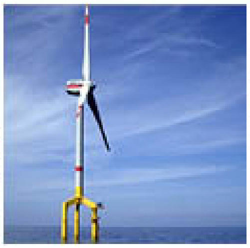


Potential Offshore Wind Energy Areas in California: An Assessment of Locations, Technology, and Costs

Walter Musial, Philipp Beiter, Suzanne Tegen, and Aaron Smith

National Renewable Energy Laboratory

This report is available from the Bureau of Ocean Energy Management by referencing OCS Study BOEM 2016-074. The report may be downloaded from BOEM's Recently Completed Environmental Studies –Pacific web page at http://www.boem.gov/Pacific-Completed-Studies/.

This study was funded by the U.S. Department of the Interior, Bureau of Ocean Energy Management.

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Technical Report
NREL/TP-5000-67414
December 2016

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Prepared under IAG No. M14PG00038; task number WFHA.1005

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Any omissions are the sole responsibility of the authors.

List of Abbreviations

AEP	annual energy production
BOEM	Bureau of Ocean Energy Management
BOS	balance of system
CapEx	capital expenditures
COD	commercial operation date
DC	direct current
EIA	Energy Information Administration
FCR	fixed charge rate
FST	Floater Sizing Tool
GIS	geographic information system
GW	gigawatt
GWh	gigawatt-hour
Hs	significant wave height
HVAC	high-voltage alternating current
HVDC	high-voltage direct current
IEC	International Electrotechnical Commission
km	kilometer
kV	kilovolt
kn	knot
kN	kilonewton
kW	kilowatt
kWh	kilowatt-hour
LCOE	levelized cost of energy
m	meter
mm	millimeter
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
TWh	terawatt-hour

Executive Summary

In this document, possible offshore wind energy locations in the state of California are examined, reference areas and potential wind plant technologies are selected, and the levelized cost of energy (LCOE)[1] between 2015 and 2030[2] is analyzed. By studying representative technology located at reference wind energy areas, cost and performance characteristics were evaluated. Reference areas were identified as sites that are suitable to represent actual offshore wind projects based on physical site conditions, wind resource quality, known existing site use, and proximity to necessary infrastructure. The intent is to assist decision-making by state utilities, independent system operators, state government officials and policy makers, the Bureau of Ocean Energy Management, and its key stakeholders. The report is not intended to serve as a prescreening exercise for possible future offshore wind development.

This study is based on assumptions and analysis from *A Spatial-Economic Cost-Reduction Pathway Analysis for U.S. Offshore Wind Energy Development from 2015–2030* (Beiter et al. 2016), which was written to support the *National Offshore Wind Strategy* (Gilman et al. 2016). The *National Offshore Wind Strategy* builds on the previous *Wind Vision* Study Scenario calling for 86 gigawatts (GW) of offshore wind deployed by 2050 in the United States. Under this scenario, 20% (17.2 GW installed capacity) of the nation's total offshore wind comes from the Pacific coastal states (DOE 2015). Although most of the offshore development activity has been focused in Europe in water depths of 50 meters (m) or less, 96% of California's offshore resource is located in waters with depths greater than 60 m. These deeper waters will likely require floating wind technology, which is still in a nascent stage of development, but is advancing toward commercialization in both Europe and Asia. The eventual commercialization of floating offshore wind is supported by market indicators such as accelerating deployment, improving cost, and increasing global research and development spending (Beiter et al. 2016). Cost-reduction scenarios point to fixed-bottom and floating wind LCOE benchmarks that may converge within the next decade. These cost reductions may enable floating offshore wind to compete in California electricity markets to help meet state renewable energy targets. In addition, other inherent offshore wind attributes may indirectly add further value to the California economy through reductions in state water consumption (via displaced fossil generation), complementary diurnal load characteristics with solar energy, and reduced transmission constraints due to proximity to dense population centers.

Six sites were identified that met the site selection criteria needed to sustain a major commercial offshore wind project. These criteria include:

- Annual average wind speeds greater than 7 meters per second (m/s)
- Water depths shallower than 1,000 m
- Lowest use conflicts

[1] Costs estimated for this report do not include subsidies or incentives.
[2] All reported years represent Commercial Operation Date (COD), unless indicated otherwise.

- Access to transmission on land (not required but evaluated)
- Suitable ports for installation and service
- Minimal visual impacts from nearshore siting.

Figure ES-1 shows the six identified reference areas, ports, potential interconnection sites, and transmission lines. Table ES-1 provides geographic details and modeling assumptions used for these sites.

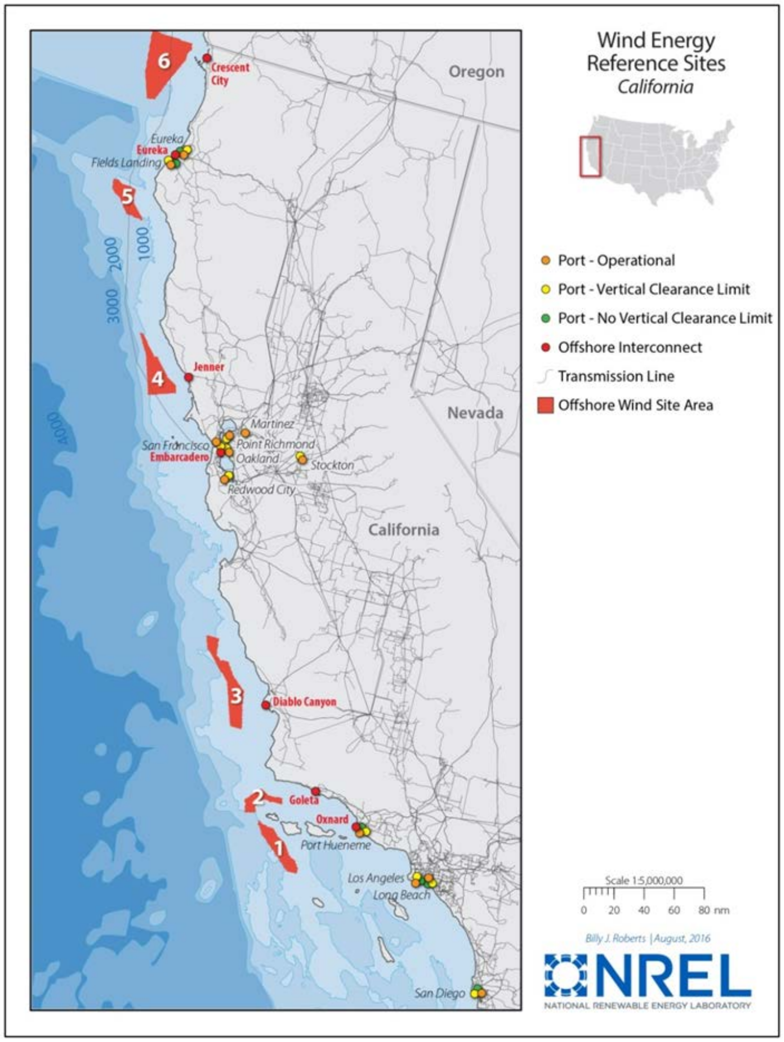

Figure ES-1. Map of offshore wind reference areas used to perform physical site and economic analysis of floating offshore wind in California

Present and future costs among these six representative offshore wind locations were estimated. Two of the reference sites were selected because they represent typical conditions in northern and southern California, respectively, and were used to conduct more detailed cost assessments. The analysis also provides a proxy for the scale of possible offshore wind development to meet

California's future electricity demand and state renewable energy targets, up to 50% renewables and beyond.

Table ES-1. Summary of Representative Sites

Offshore Wind Reference Area	2 – Channel Islands North	5 – Humboldt Bay Area
Mean wind speed (m/s) at 100 m hub height	8.86	9.73
Min, mean, max significant wave height (m)	1.8/2.3/2.5	2.7/2.7/2.8
Min, mean, max depth (meters)	198/575/774	592/870/994
Construction port	Port Hueneme, CA	Fields Landing, CA
Operation and maintenance (O&M) port	Port Hueneme, CA	Fields Landing, CA
Centroid distance to centroid distance to O&M port (straight line - km)	127	78
Centroid distance to centroid distance to O&M port (avoids land - km)	127	87
Interconnection point	Goleta, CA	Eureka, CA
Centroid distance to interconnection (offshore until landfall) (straight line - km)	69	80
Centroid distance to interconnection (offshore until landfall) (avoids land - km)	69	87
Distance point of cable landfall to interconnect (km)	6	5
Area (km^2) < 1,000 m depth	445	431
Total potential capacity (MW)	1,335	1,293

Based on engineering experience with continued turbine size growth and available market trend information, technology assumptions were made as a basis for an analysis of future costs. Table ES-2 describes the technology assumptions modeled in this study.

Table ES-2. Technology Assumptions for California Offshore Wind Cost Analysis

	2015 Technology	2022 Technology	2027 Technology
Turbine Rated Power (MW)	6	8	10
Turbine Rotor Diameter (m)	155	180	205
Turbine Hub Height (m)	100	112	125
Turbine Specific Power (W/m^2)	318	314	303
Substructure Technology	Semisubmersible	Semisubmersible	Semisubmersible

Net annual energy production was calculated using these technology assumptions and site wind characteristics, including losses as a result of wakes, electrical transmission, availability, drivetrain conversion, and other system inefficiencies.

Using the technology assumptions in Table ES-2, the cost analysis also considered the variation in offshore resource quality and relevant physical characteristics along the California coast, including distance from shore, water depth, and wave height. The change in LCOE for a given site resulting from expected technology innovations and advancements was also modeled for three target years—2015, 2022, and 2027—for projects at their commercial operation date (COD). In addition, these modeled costs were extrapolated to 2030.

For developing cost reductions specific to floating technology, we followed the methodology framework and inputs of the DELPHOS tool developed in the United Kingdom by BVG Consulting and KIC InnoEnergy (Valpy 2014), but included a modified set of cost-reduction options to account for differences between fixed and floating offshore wind technology. The DELPHOS cost assessment builds from The Crown Estate's *Offshore Wind Cost Reduction Pathways Study* (2012) and from European offshore wind experience. The resulting method provides a comprehensive, bottom-up assessment of the potential to reduce the cost of multiple subelements of a project's capital cost breakdown structure, including improvements to system reliability and performance. The results of this cost analysis for California are shown in Figure ES-2 for the two representative sites described in Table ES-1. Table ES-3 provides the same data in tabulated form.

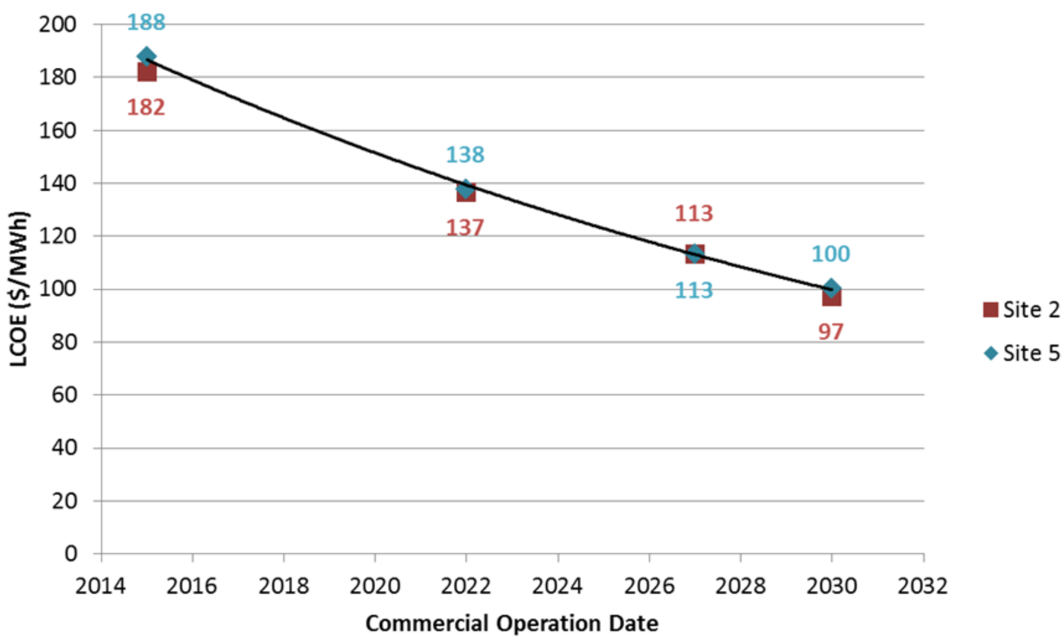

Figure ES-2. Estimated (unsubsidized[3]) LCOE for California sites 2 (Channel Islands North) and 5 (Humboldt Bay)

[3] These estimates are made 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). Further, accelerated depreciation (Modified Accelerated Cost Recovery System) is considered.

Table ES-3. Estimated LCOE for the two representative Californian sites (unsubsidized)

Year (COD)	LCOE (in $/MWh)	
	Site 2 (Channel Islands North)	Site 5 (Humboldt Bay)
2015	182	188
2022	137	138
2027	113	113
2030	97	100

The similarity in the LCOE values and cost reduction trends plotted in Figure ES-2 are a result of comparable geographic conditions and wind speeds. The analysis estimates that the LCOE of both sites has the potential to decrease from approximately $185/megawatt-hours (MWh) in 2015 (COD) to approximately $100/MWh by 2030 (COD).

The limitations of this analysis are described in more detail in Beiter et al. (2016) and in Section 6 of this report. In general, the following limitations should be considered:

- The modeled cost reduction trajectory depends, in part, on continued global investments in offshore wind technology innovation, and the emergence of a robust domestic and Californian supply chain commensurate with recent European supply chain developments.
- The cost-reduction pathways modeled were developed from European project data but the study does not provide analysis to convert European to U.S. and Californian offshore wind market conditions. U.S. projects may have different risk and uncertainty profiles because of varying geographic (e.g., deeper waters) and market conditions (e.g., policy).
- The cost model incorporates a number of simplifications and uncertainties including first-order tools that may not reflect some details in the design, lack of U.S. commercial-scale offshore wind experience, uncertainty in technology suitability and availability, and uncertainty in macroeconomic factors (e.g., exchange rates, commodity prices).
- This analysis does not consider policy-related factors or subsidies, either at the national level or in California.
- The full set of environmental issues was not taken into account. The authors recommend that offshore wind developers work closely with regulatory bodies including BOEM, the U.S. Environmental Protection Agency, Federal Aviation Administration, and California state and local agencies to ensure they are considering conservation areas, marine-protected areas, habitats, migration patterns, marine flora, and many other important environmental factors.
- The time frame considered only the period to 2027 (COD) (LCOE results are extrapolated to 2030). Because floating offshore wind technology is still in a nascent stage of development, the analysis period should be considered a near-term window.

- Fixed-bottom offshore wind project costs are decreasing more rapidly than anticipated by many industry cost models, including the cost-reduction pathway estimated by this analysis. Recent competitive tenders include Borssele I&II in the Netherlands (58% reduction in power price from 2010) and Krieger's Flak in Denmark (59% reduction in power price relative to projections made in 2012). The extent that these lower costs can be sustained and passed on to floating technology is not evaluated.
- The quantitative values provided in the DELPHOS bottom-up analysis have not yet been independently verified (however, general trends are supported by historic learning curves from similar industries that show that cost reductions of this magnitude are possible). Cost-reduction opportunities included in the DELPHOS analysis for floating wind turbines did not undergo the same level of review as the original 40 cost-reduction areas determined by The Crown Estate. Because of a lack of industry experience in floating wind and the preliminary status of this analysis, there is a higher degree of uncertainty in the floating criteria presented.

The key findings drawn from this analysis indicate:

- There is 112 GW of technical offshore wind resource potential over the entire California coastline. This corresponds to 392 TWh/year of potential energy production, or about 1.5 times the state's electric energy consumption based on 2014 EIA figures (Musial et al. 2016; Energy Information Administration 2015a).
- Ninety-six percent of the technical offshore wind resource is in waters deeper than 60 m, indicating that floating wind technology will likely be the most viable option in California (Musial et al. 2016).
- The six reference sites have a combined installed capacity potential of over 16 GW and illustrate that offshore wind could potentially be deployed at a scale large enough to significantly contribute to California's electricity demand for low carbon energy.
- Market growth indicates an emerging market for floating wind turbines worldwide and expected commercial phase development by 2025.
- The variation in offshore resource quality and spatial characteristics along the California coast including distance from shore, water depth, and wave height resulted in relatively small variations in LCOE at the reference sites for 2015, 2022, 2027 (modeled), and extrapolated to 2030.
- Relatively small differences in LCOE were found between the representative sites 2 and 5, which are indicative of site similarities among the potential California offshore wind sites. Site selection was primarily guided by higher wind speeds and lower water depth. However, because the water depth increases rapidly, all of the sites were a similar distance from shore (approximately 30 km [see Figure 13]), to avoid nearshore visual impacts and far shore extreme water depths.

- The cost-reduction potential for the two reference sites was also very similar. Site 2 showed potential LCOE reductions from $182/MWh to $97/MWh whereas site 5 showed potential reductions from $188/MWh to $100/MWh. These similarities are indicative of the cost-reduction assumptions used and the physical site similarities.
- The baseline cost of the 2015 floating offshore wind technology is derived from only a few deployments in Europe that are now several years old, but these California baseline starting points ($187/MWh average across the six considered sites) are the primary element used to establish LCOE in later years. The higher degree of uncertainty in the floating baseline suggests a possible range of future costs when the existing baseline data are updated.
- The economic potential for offshore wind to compete at the estimated costs in California is dependent on technology attributes, market factors, prevailing electricity prices, and the level of policy support for the year being considered.
- Grid connections and port services are more abundant and readily accessible in southern California, which may facilitate near-term development in these areas.
- California has a relatively severe wave climate that contributes to higher LCOE estimates driven up by increased operation and maintenance (O&M) and lower availability. New turbine access methods, tow-to-shore O&M strategies, and mooring/array cable system designed for easy connect/disconnect could help mitigate these challenges.
- To illustrate the potential contribution of offshore wind: if 1.2 GW (two 600-MW wind plants) were installed at each of the six reference sites, 35.3 terawatt-hours/year of offshore wind could be added to the existing generation. This level of generation would be approximately 13.5% of California's 2014 electric energy demand.[4]
- Floating wind technology is in a nascent stage and it is unknown at this point which configuration could achieve the lowest costs. However, given recent declines in the cost of energy from fixed-foundations offshore wind projects and the level of innovative floating foundation design work that is now underway, we would expect cost estimates for these technologies to change over time.

[4] This scenario would use less than half of the area indicated in Figure ES-1.

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1 Introduction

This report summarizes a study of possible offshore wind energy locations, technologies, and levelized cost of energy (LCOE)[5] in the state of California between 2015 and 2030.[6] The study was funded by the U.S. Department of the Interior's Bureau of Ocean Energy Management (BOEM), the federal agency responsible for regulating renewable energy development on the Outer Continental Shelf. It is based on reference wind energy areas where representative technology and performance characteristics were evaluated. These reference areas were identified as sites that were suitable to represent offshore wind cost and technology based on physical site conditions, wind resource quality, known existing site use, and proximity to necessary infrastructure. The purpose of this study is to assist decision-making by state utilities, independent system operators, state government officials and policymakers, BOEM, and its key stakeholders. The report is not intended to serve as a prescreening exercise for possible future offshore wind development.

In its recent *National Offshore Wind Strategy* (Gilman et al. 2016), the U.S. Department of Energy (DOE) characterizes offshore wind as an abundant, low-carbon, and domestic energy resource. DOE's *Wind Vision* Study Scenario calls for 86 GW of offshore wind to be deployed by 2050 in the United States with 20% (17.2 GW) coming from the Pacific coastal states (DOE 2015; Gilman et al. 2016). More than 250 GW of offshore wind capacity are currently in the global offshore wind development pipeline (Smith et al. 2015), and recent market data from Europe show offshore wind costs decreased at a higher-than-expected rate in 2016, signaling improving market conditions.[7] Although most of the offshore development activity has been focused in Europe in water depths of 50 m or less, the success of fixed-bottom offshore wind technology in shallow water along with increased market certainty and lower costs are stimulating interest in new floating wind technology for coastal markets with deeper water.

In the United States, construction of the first offshore wind farm, the 30-MW Block Island Wind Farm off the coast of Rhode Island, was completed in 2016. The project uses fixed-bottom platform structures in water depths of less than 30 m. However, along the Pacific Coast of California, 96% of the technical wind resource potential is in water depths greater than 60 m. In these deeper waters, floating wind technology will likely be required.

To date, worldwide deployment of floating platforms is limited to a handful of full-scale prototype floating turbines, including prototypes by Statoil (Hywind-I with a Siemens 2.3-MW turbine), Principle Power (WindFloat I with a Vestas V-80 2 MW turbine), two projects at Fukushima Forward (Hitachi 2-MW and 5-MW turbines), Kabashima (Hitachi 2-MW turbine), and Mitsubishi Heavy Industries (MHI/Vestas 7-MW turbine).

[5] Costs estimated for this report do not include subsidies or incentives.
[6] All reported years represent the commercial operation date, unless indicated otherwise.
[7] For instance, winning tenders of $55/MWh (e.g., Vattenfall, Kriegers Flak [2016]) (Source: Steel 2016); converted from euros to USD based on November 2016 exchange rate) and $81/MWh (DONG Energy [2016], Borssele I and II) in 2016 and $114/MWh (Vattenfall, Horns Rev III) in 2015 (both projects exclude transmission costs) (Beiter et al. 2016).

Although floating wind technology is still at a precommercial stage, recent industry project data suggest that a commercial market for floating wind turbines may be emerging (Beiter et al. 2016); however, the technology is less mature and costs are currently higher than for fixed-bottom technology. In Beiter et al. (2016), cost-reduction scenarios indicate fixed-bottom and floating wind costs may converge within the next decade. These cost reductions may enable floating offshore wind to compete in California electricity markets to help meet state renewable energy targets.

As one of the largest economies in the world, California is also a global leader in greenhouse gas reduction. New policies passed in 2015[8] include a state mandate for 50% renewable energy electric generation by 2030, increasing the urgency to find renewable energy sources to meet this requirement. Offshore wind energy has the potential to meet some of this demand in the future, and has other positive attributes that could further increase its regional value. Value-adders include the proximity of the resource to the coastal high-density populations, and thus load centers. As shown in Figure 1, a large percentage of California's 38.8 million residents[9] live close to the state's extensive coast line, and offshore wind could potentially reduce the required transmission distances.

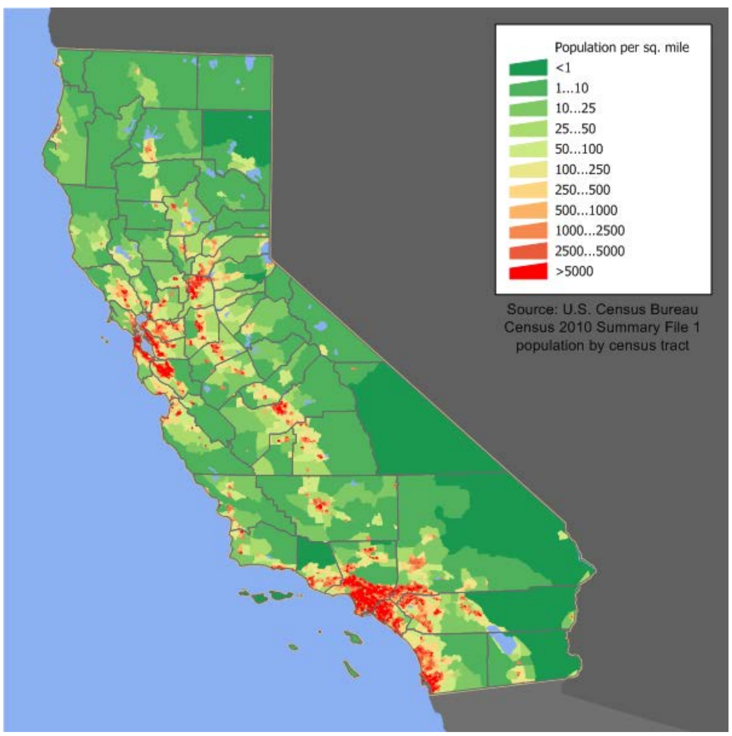

Figure 1. California population density map showing proximity of high-density population to coast. ***Image from the U.S. Census (2010)***

[8] Governor Edmund G. Brown signed California HB 350 in September 2015, which calls for reductions in greenhouse gases to 40% below 1990 levels by 2030.
[9] Based on 2016 U.S. Census Data.

Also, California has been stricken by drought for several years, and unlike thermal generation, energy generation from offshore wind does not use any of California's fresh water supply. In 2014, the American Wind Energy Association estimated that 2.5 billion gallons of water were saved by operating existing land-based wind plants in California.[10] The offshore wind resource along the California coast may also have diurnal characteristics that are complementary to the state's solar resource, where the average peak generation occurs at the end of the day and evening (Gilman et al. 2016). This complementary characteristic could potentially enable higher penetrations of renewable energy to be deployed.

For this report, we estimated present and future costs among six representative offshore wind locations in California where floating offshore wind technology could be deployed. We conducted a detailed cost assessment for two of these areas that represent averages for typical conditions in northern and southern California. As mentioned earlier, the selected sites are not intended to be a precursor for follow-on wind energy area planning, which would require a more careful study of viewshed issues and other impacts. However, the analysis provides a rough proxy for possible development that can help stakeholders understand the scale of offshore wind development relative to California's electricity demand.

This report considers the variation in offshore resource quality and relevant physical characteristics along the California coast, including distance from shore, water depth, and wave height. It also offers an understanding of the change in LCOE for a given site resulting from expected technology innovation and advancement by modeling three financial close target years, 2013, 2020, and 2025 and extrapolating these modeled values to 2030. In estimating costs, this study combines a variety of modeling capabilities with data for resource and climate, infrastructure, land-use siting, and a technology assessment. Information sources include:

- An offshore wind resource assessment study (Musial et al. 2016), which identified the technical potential for offshore wind development in the United States on a state-by-state basis
- GIS and mapping capabilities at the National Renewable Energy Laboratory (NREL)
- Geospatial conflicting-use and environmental data identified by Black & Veatch (2010 unpublished) and compiled in a GIS-based layer on the BOEM aliquot grid[11]
- Hourly wind resource data recently added to the Wind Prospector Tool (NREL Wind Prospector 2016)
- Windographer software developed by AWS Truepower to assess annual hourly wind speed distributions (8,760 hours) and energy production on a site-by-site basis
- An Openwind wake loss model developed by AWS Truepower (AWS Truepower 2010)

[10] California wind power capacity is estimated to be about 6 GW http://www.energy.ca.gov/almanac/renewables_data/wind/

[11] Aliquots are subcomponents of lease blocks.

- A geospatial offshore wind cost model documented in Beiter et al. (2016).

The report is organized as follows: Section 2 provides an overview of California's offshore wind energy resources and describes the methodology and results of identifying offshore wind areas in California suitable for development based on the criteria of this study. Section 3 describes the technology assumptions used to determine the baseline 2015 wind turbine and floating foundation size and configuration, as well as the expected turbine and platform configurations for future years. Section 4 describes the method of calculating energy production at each reference area including the expected energy losses. Section 5 provides an overview of the wind power plant cost modeling approach and methodology. Section 6 describes the limitations of the analysis. Section 7 discusses findings from the cost analysis, and Section 8 summarizes the conclusions. Section 9 outlines possible next steps.

2 Identification of Reference Offshore Wind Areas

2.1 California Offshore Wind Resources

The offshore wind resources in California were evaluated by Musial et al. (2016) in terms of capacity and energy potential. The gross potential resource capacity for California was found to be 1,698 GW, if we consider all the ocean area from the shoreline to the Exclusive Economic Zone boundary located 200 nautical miles (nm) from shore and the distance from the Mexican to the Oregon border. Gross capacity is not, however, a practical metric for future deployment because much of the resource area is constrained by technology limits of extreme water depth or low wind speed.

Following the terminology developed by Beiter and Musial (2016), when water depth, low wind speeds, known sensitive environmental areas, and technology constraints are taken into consideration, the gross potential is reduced to the "technical resource potential." The technical resource potential captures the subset of gross resource potential that could become commercially viable using available technology. For the purpose of this study and consistent with Musial et al. (2016), this resource area only includes water depths less than 1,000 m and wind speeds greater than 7 m/s. Technical potential excludes known sensitive environmental areas such as ecological preserves, closed areas, marine-protected areas, National Marine Sanctuaries, National Wildlife Refuges, National Park Service areas, critical habitat, and habitat areas of particular concern (e.g., Canopy Kelp) (Black & Veatch 2010).[12]

The technical offshore wind resource potential for California was computed to be 112 GW across the entire coastline (Musial et al. 2016). This amount corresponds to 392 TWh/year of potential energy production, which is about 1.5 times the state's electric energy consumption (Musial et al. 2016; Energy Information Administration [EIA] 2015a). In California, only 5.1 GW of resource capacity potential can be found in waters with depths of 60 m or less.[13] Virtually all of this shallow water offshore wind potential is found in state waters within 3 miles of the coast, where concerns relating to views and migratory birds may be particularly acute. Figure 2 shows a map of the average annual California wind speeds over the technical resource area outside of a 3-nm boundary area.[14]

[12] Black & Veatch data are not published but were provided to NREL as GIS data layers where shipping lanes or areas of environmental concern are located. In general, energy development would be prohibited in protected areas (e.g., marine sanctuaries). Development is not necessarily prohibited in all areas of environmental conflict, though mitigations may be required. For offshore wind energy, developers will need to work with all appropriate federal, state, and local agencies and organizations for permitting.

[13] Resource capacity estimates are based on 3 MW/km^2 array power density from Musial et al. (2016).

[14] State waters extend to 3 nm from the shoreline, which are not under BOEM's jurisdiction.

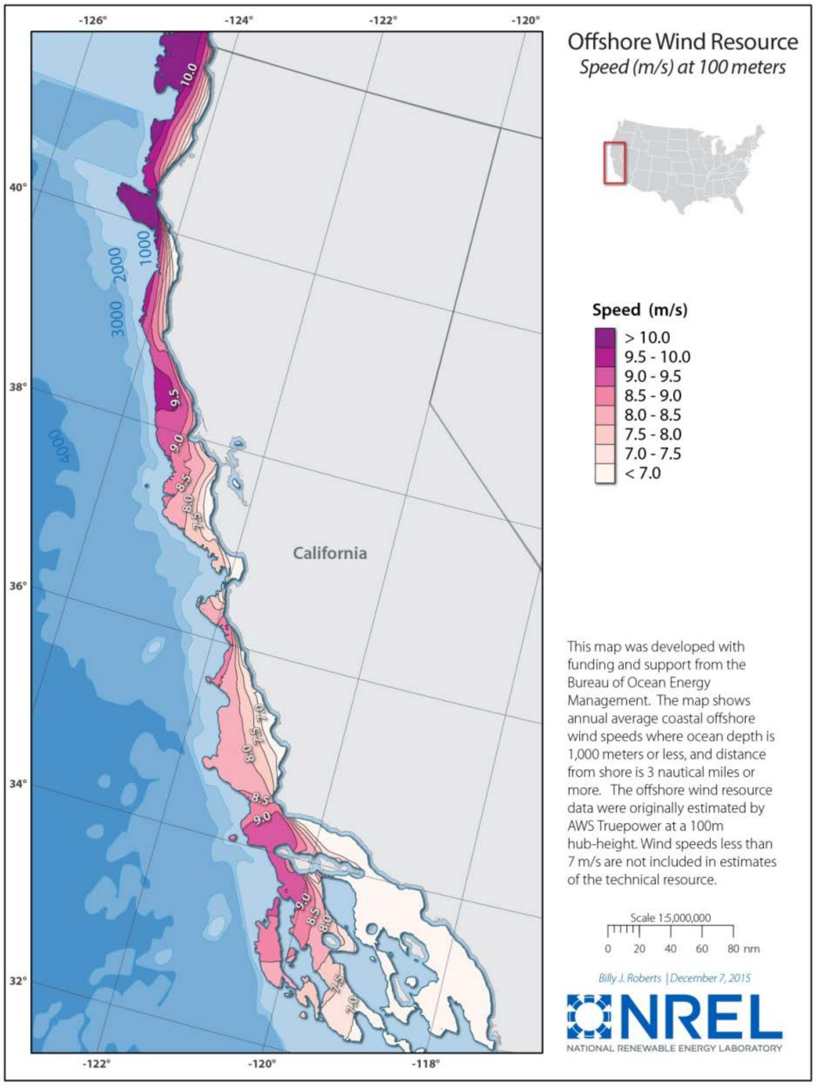

Figure 2. Wind speed map of California offshore technical wind resource area calculated at a 100-m elevation above water

The wind speeds in the map were adjusted to a reference height of 100 m above the water, the nominal hub height of current offshore wind turbines. Data were extrapolated from a 90-m elevation to 100 m based on statistical data developed by AWS Truepower (AWS Truepower LLC 2012). Figure 2 shows that the best wind speeds are located near and north of the Channel Islands and north of San Francisco to the Oregon border. Figure 3 shows the gross and technical offshore wind resource potential for California by water depth.

Globally, almost all of the offshore wind development to date has included fixed- bottom foundations in waters 50 m or less (Smith et al. 2015); but because 96% of California's offshore resource is located in waters with depths greater than 60 m, it is expected that if offshore wind is to become a substantial part of the California energy mix, floating wind will likely be the dominant technology used.

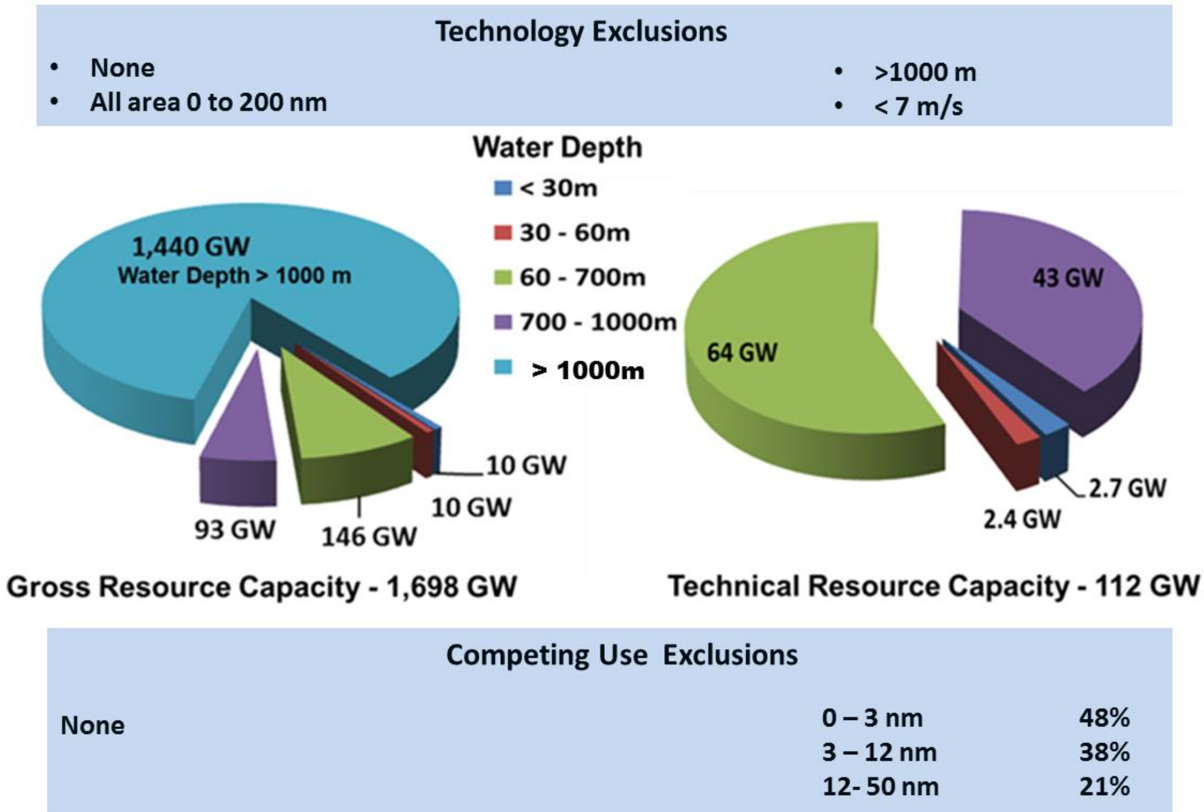

Figure 3. Comparison of California gross offshore resource to technical resource potential by water depth (Musial et al. 2016)

2.2 Identification of Offshore Wind Reference Areas

To assess the present and future cost of floating offshore wind turbines in California, representative areas were identified to serve as reference sites for calculating LCOE while considering the impacts of geospatial characteristics. Many cost variables were evaluated in making these site selections that resulted in six reference areas. These six selections were narrowed to two typical sites that serve as the final cost reference presented in Section 7 (See Figure 5 for site locations).

It is important to note that although the selection process in this study used the best available information, the process is not intended to supplant a rigorous stakeholder-based marine-spatial planning process that all offshore wind projects would be expected to undergo; the sites described in this report are intended to be used for illustrative purposes only. Nevertheless, these sites provide actual locations that allow us to assess and compare the impact of key geospatial parameters on offshore wind system cost. These parameters include wind resource, wave climate, bathymetry, existing grid infrastructure, distance to ports and grid connections, offshore wind technology (likely to be available in the study timeframe from 2015 to 2030), and existing use and environmental constraints.

The following criteria were considered in the site selection:

- Annual average wind speed greater than 7 m/s
- Water depths shallower than 1,000 m
- Lowest use conflicts
- Access to transmission on land (not required but evaluated)
- Suitable ports for installation and service (does not consider required improvements[15])
- Distance from shore (see Figure 13).

Figure 4 shows the wind speed map from Figure 2 with the primary competing use (e.g., shipping and ports [yellow and orange]) and environmental consideration layers (blue) overlaid (Black & Veatch 2010 unpublished). The areas where the wind speed contours are not covered by one of these conflicting uses in Figure 4 were considered low conflict areas for this preliminary assessment.

[15] This report assumes that the ports identified will be available and that if upgrades are needed they will be implemented outside the project costs estimated in this report.

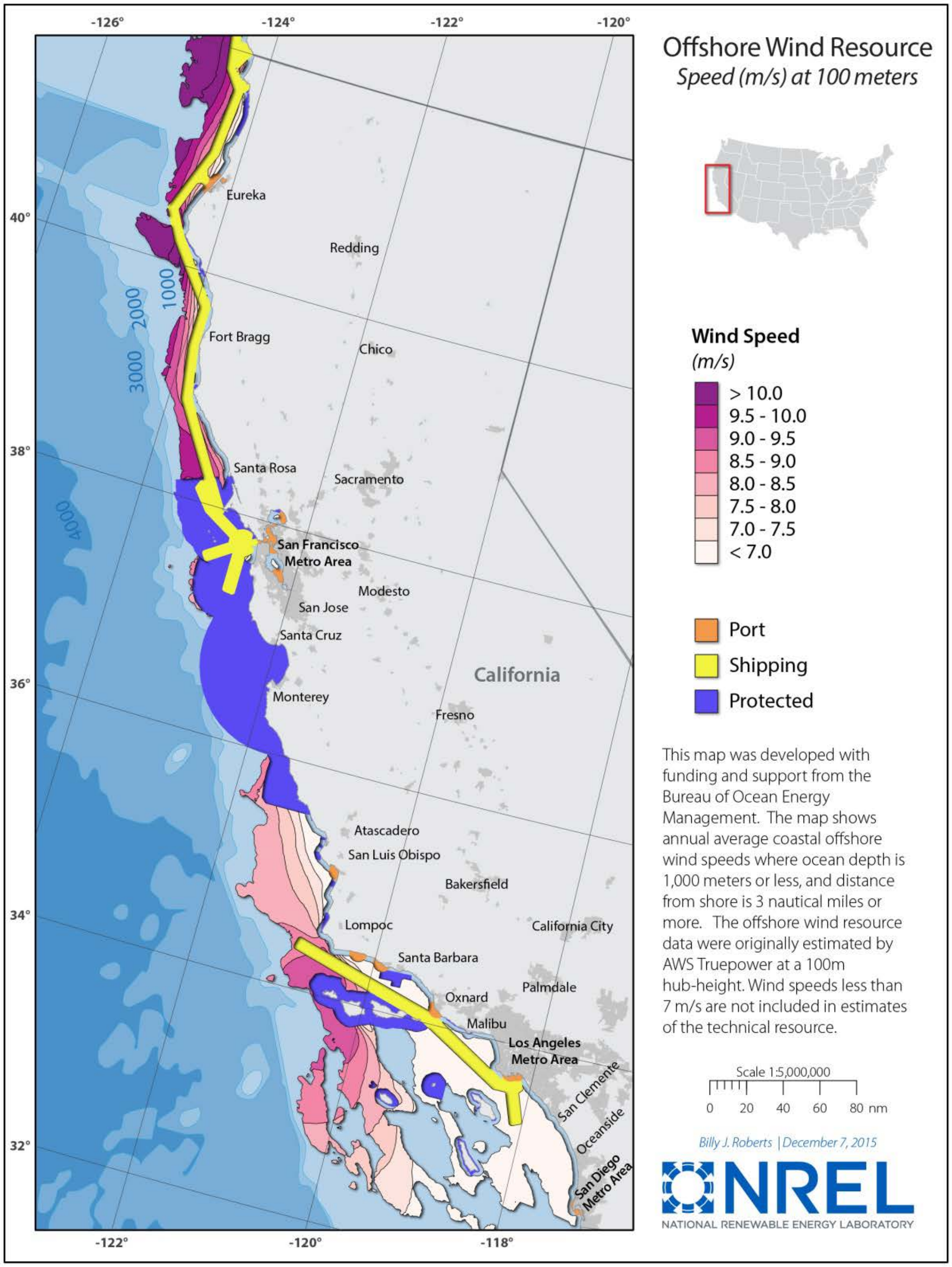

Figure 4. Wind speed map of California offshore technical resource area with competing use and environmental conflicts overlaid

Note that in Figure 4, the shipping lanes shown (include a buffer zone recommended by maritime operators) may not be areas excluded from offshore wind development. However, we chose to avoid the designated shipping lanes for this initial assessment. Figure 5 shows a map of the wind speed areas without competing uses (a combination of Figures 2 and 4 with ports, shipping lanes, and protected areas removed). Approximate locations of the offshore wind reference sites are indicated with numerical labels.

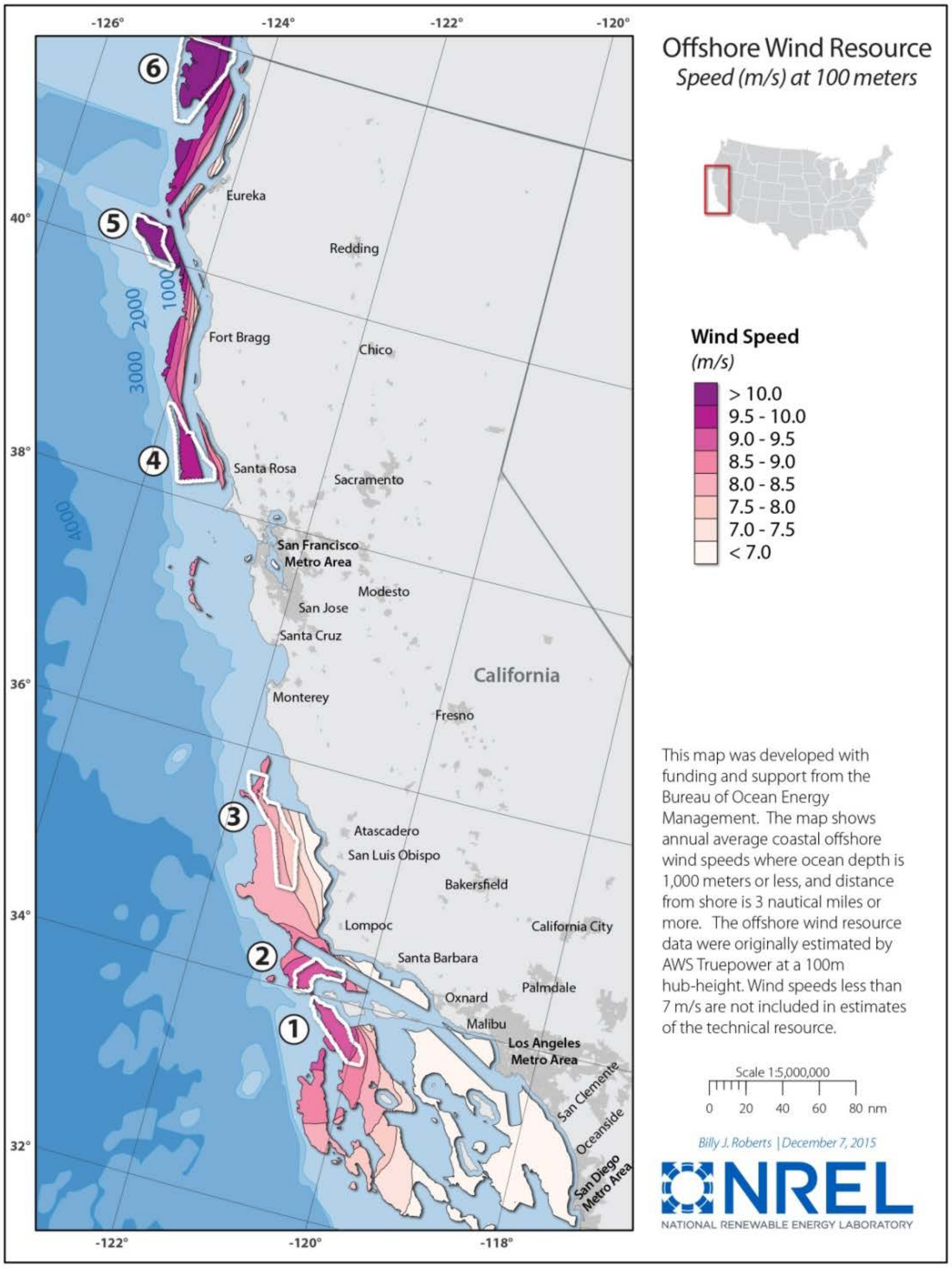

Figure 5. Wind speed map of California offshore technical resource area with shipping lanes, ports, and known environmental conflict areas removed showing outlines of six reference sites

As indicated by the numerical labels on the map in Figure 5, six sites were identified that met the site-selection criteria to sustain a major commercial offshore wind project. Each of these reference sites was further evaluated to define a specific area on the BOEM aliquot/lease block grid. Figure 6 shows all six reference areas, ports, potential interconnection sites, and transmission lines.

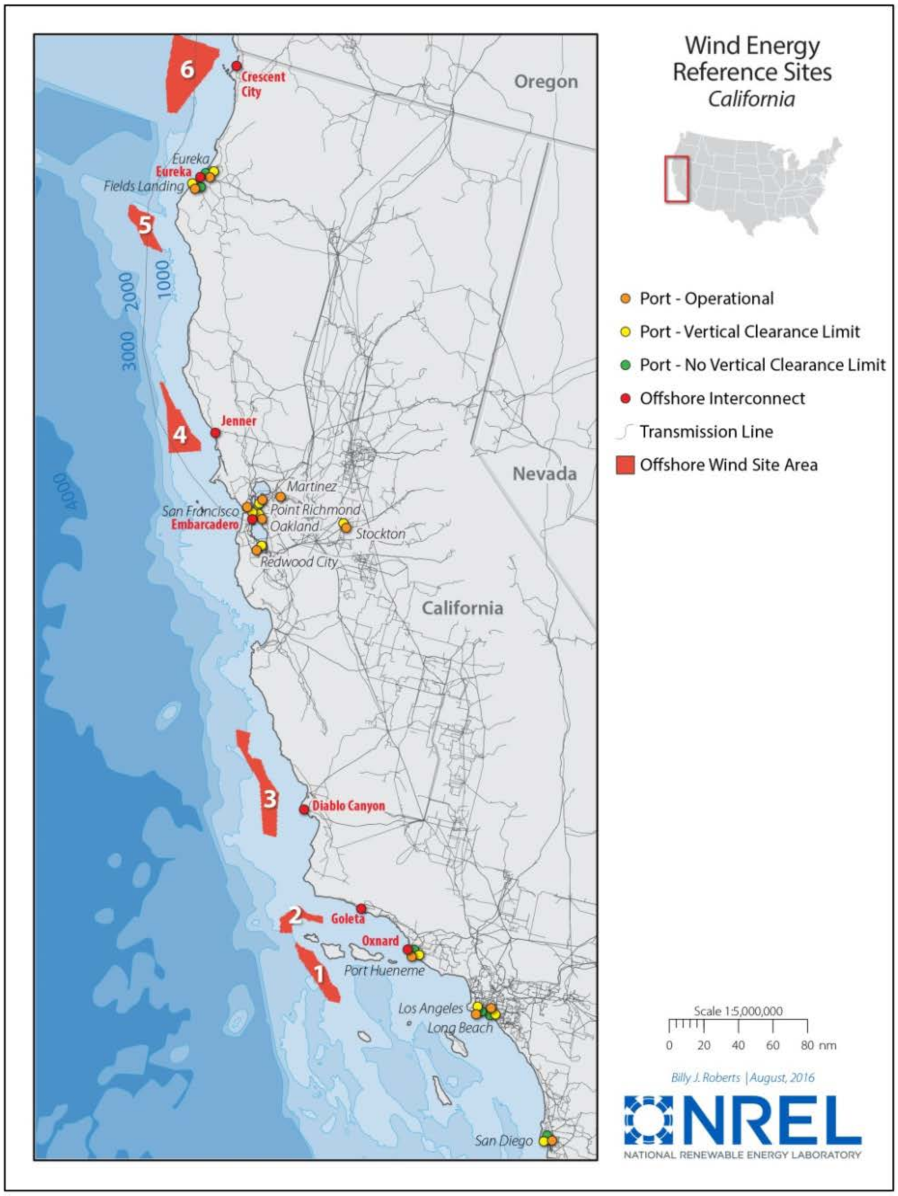

Figure 6. Map of offshore wind reference areas used to perform physical site and economic analysis of floating offshore wind in California

Figure 7 through Figure 12 show each of the offshore wind reference areas identified in Figure 6 at a closer scale. The BOEM lease grid is shown in each map, represented by the numbered squares. Each lease block measures 4.8-km-by-4.8-km (area 23.04 km^2) and is subdivided into 16 aliquots that are square areas measuring 1.2-km-by-1.2-km (area 1.44 km^2). This analysis created boundaries for each reference site that preserved whole aliquots and sought to remain in the areas of good wind and low conflicts. Going forward in the report, no further reductions or restrictions were assumed.

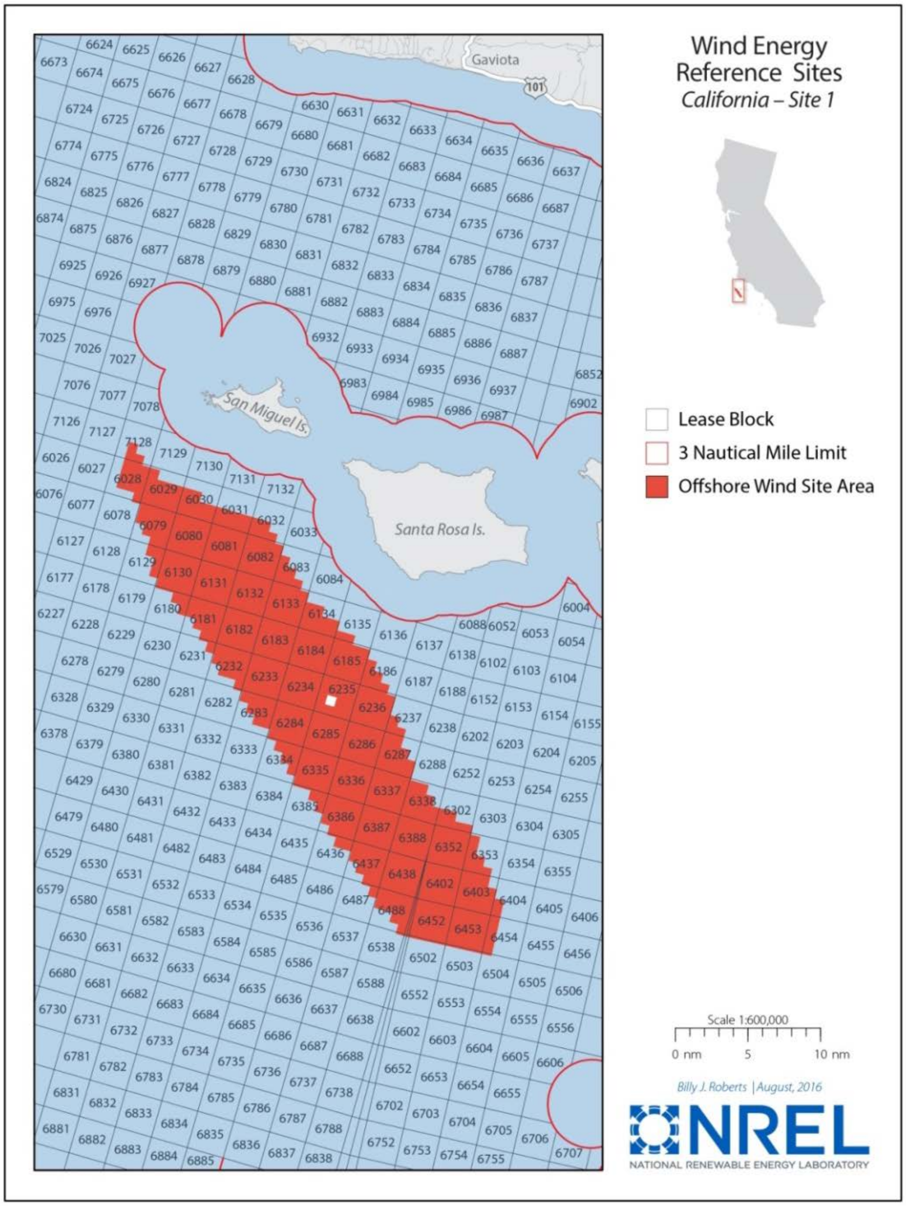

Figure 7. Map of offshore wind reference area 1, known as Channel Islands South; the white square in lease block 6235 highlights the representative aliquot for this reference area

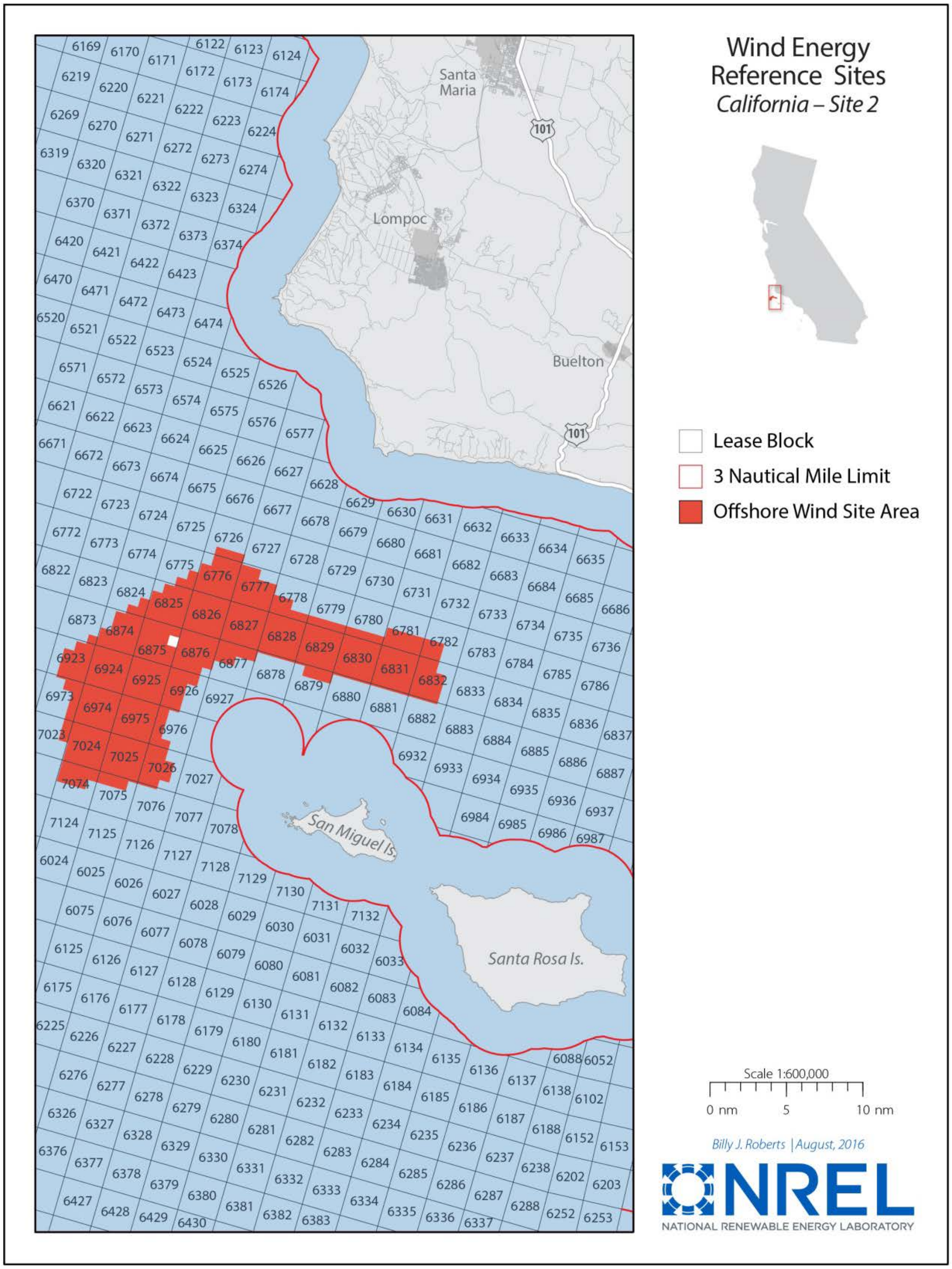

Figure 8. Map of offshore wind reference area 2, known as Channel Islands North; the white square in lease block 6875 highlights the representative aliquot for this reference area

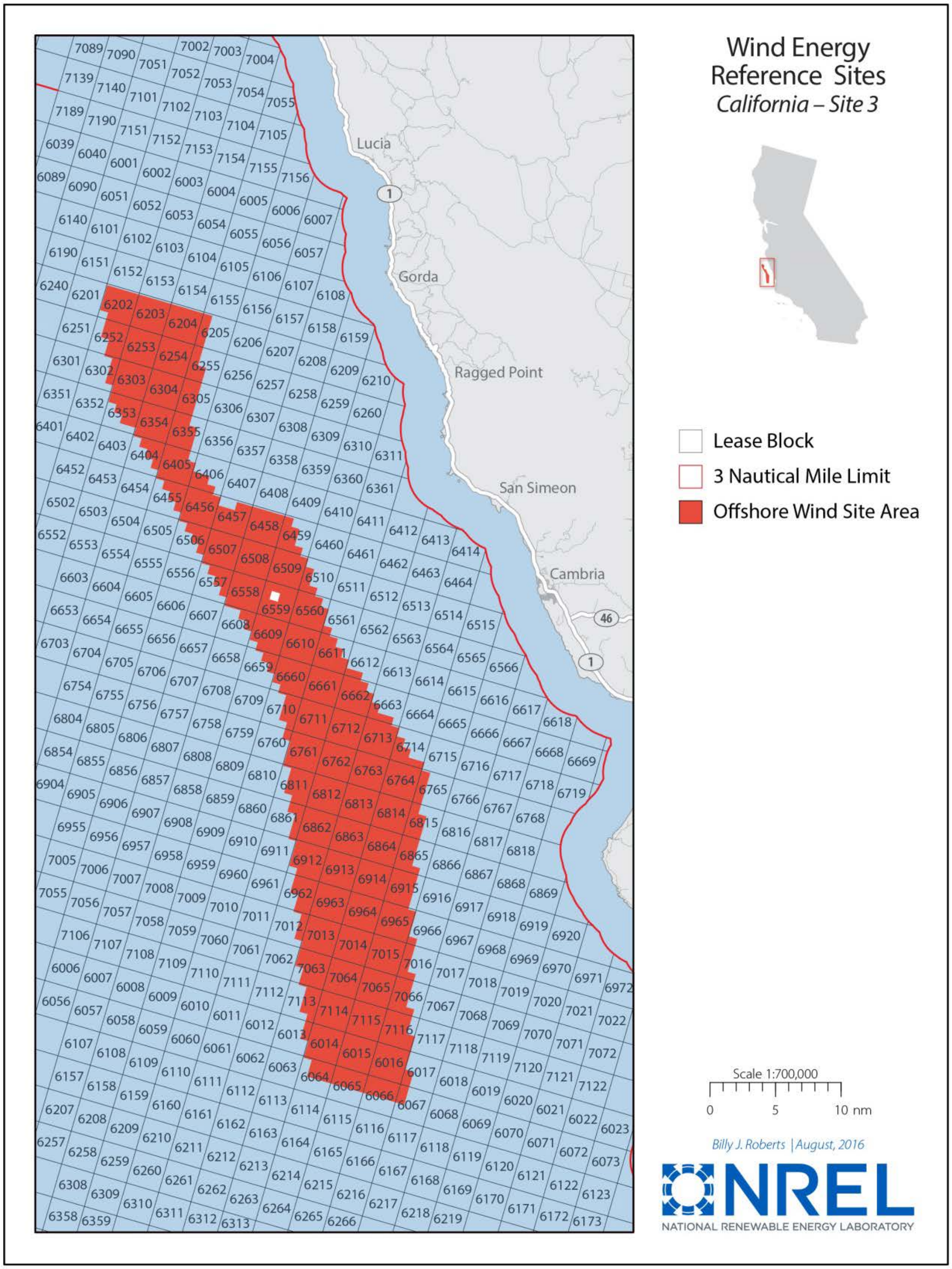

Figure 9. Map of offshore wind reference area 3, known as Morro Bay Area; the white square in lease block 6559 highlights the representative aliquot for this reference area

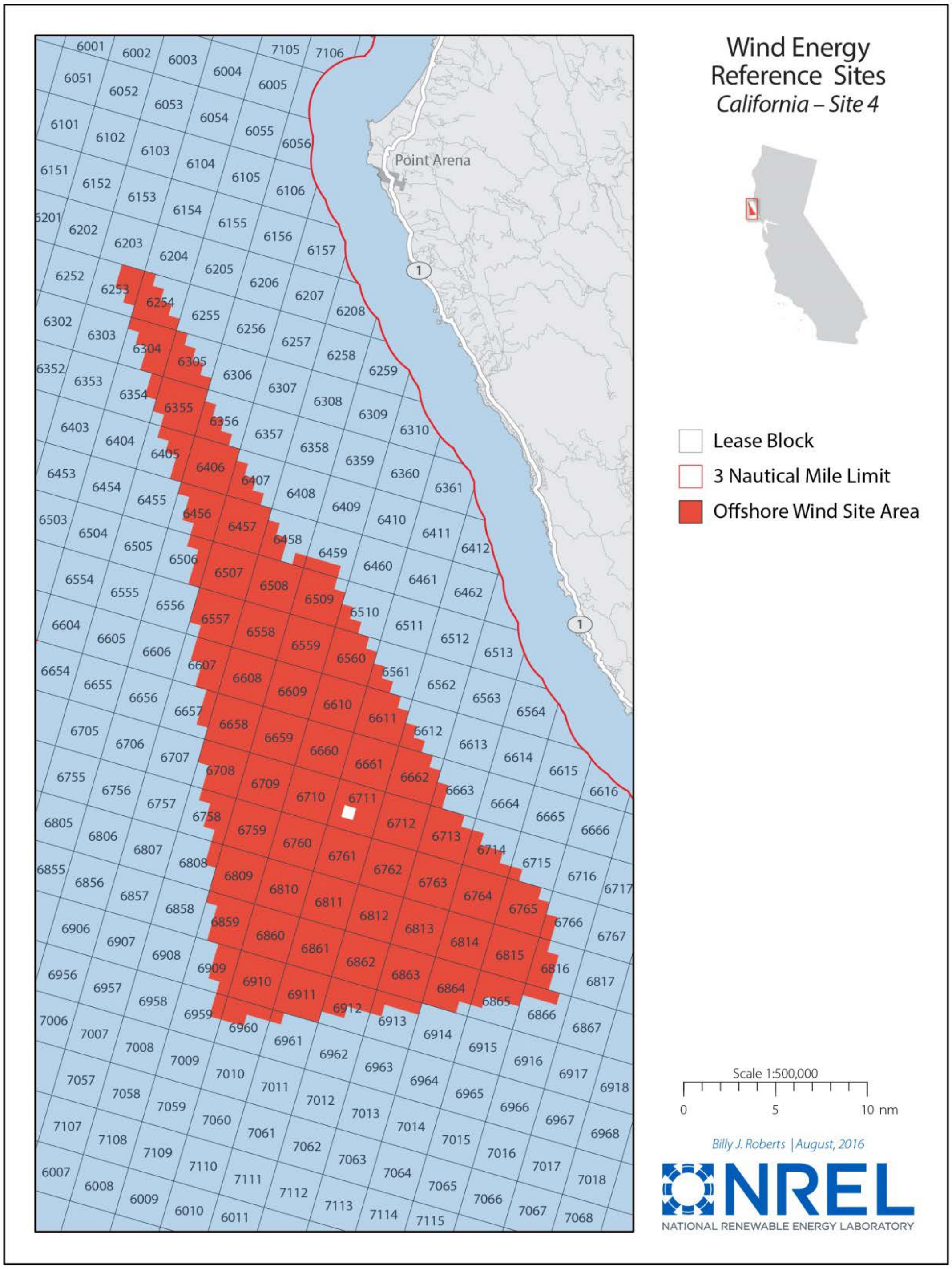

Figure 10. Map of offshore wind reference area 4, known as Bodega Bay Area; the white square in lease block 6711 highlights the representative aliquot for this reference area

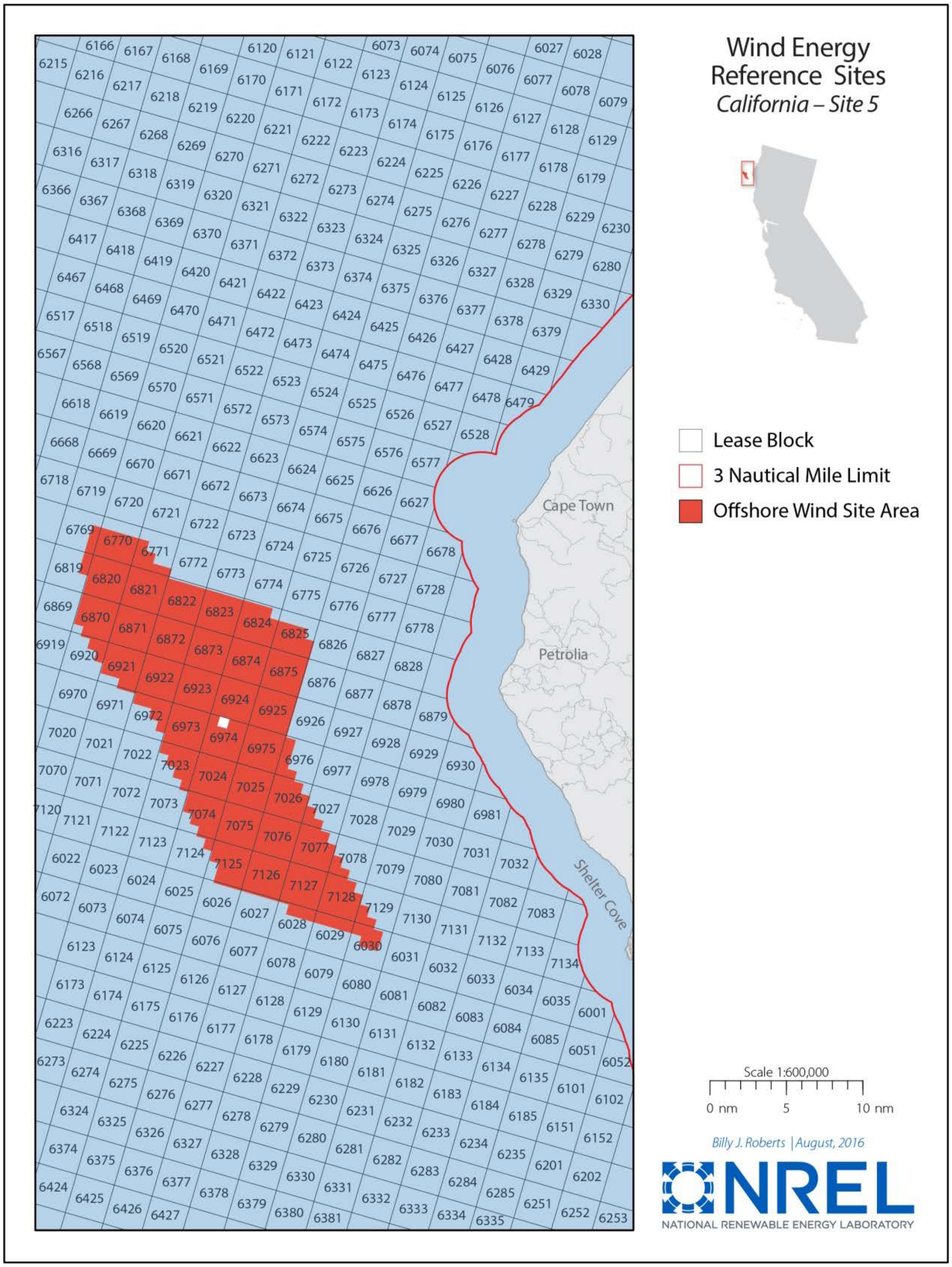

Figure 11. Map of offshore wind reference area 5, known as Humboldt Bay Area; the white square in lease block 6974 highlights the representative aliquot for this reference area

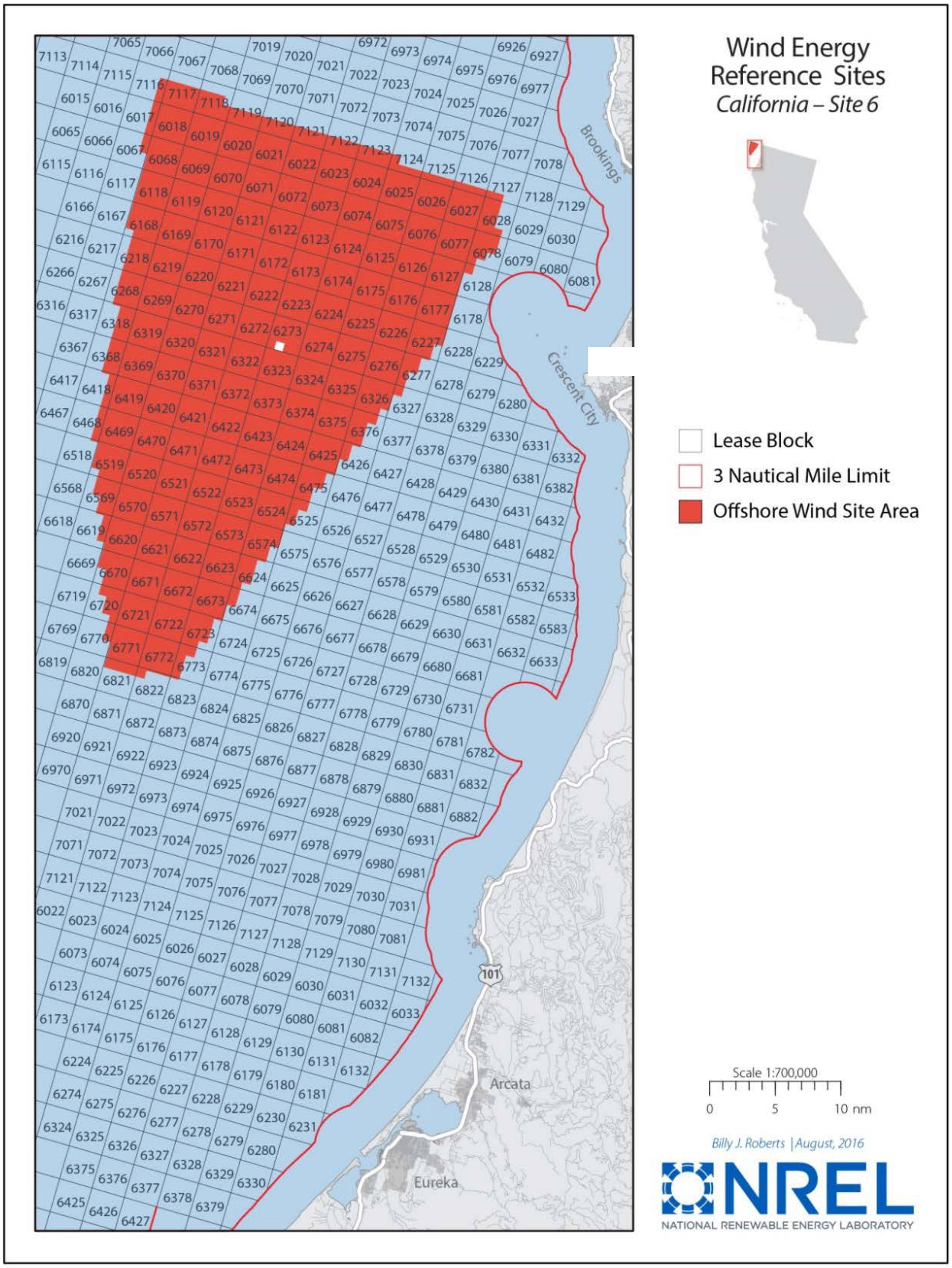

Figure 12. Map of offshore wind reference area 6, known as Crescent City Area; the white square in lease block 6273 highlights the representative aliquot for this reference area

These reference offshore wind areas were drawn on each map around a boundary that follows the BOEM lease grid subdivided by aliquots. For each reference area, assumptions and site characteristics are provided in Table 1.

Table 1. Reference Area Site Characteristics

Offshore Wind Reference Area	Channel Islands South	Channel Islands North	Morro Bay Area	Bodega Bay Area	Humboldt Bay Area	Crescent City Area
Site Identification Number	1	2	3	4	5	6
Representative Point Latitude	33.734614°	34.188565°	35.458256°	38.355489°	40.133304°	41.699739°
Representative Point Longitude	120.18475°	120.66088°	121.50439°	123.52929°	124.73094°	124.76659°
Centroid Latitude	33.72	34.16	35.32	38.41	40.13	41.66
Centroid Longitude	-120.21	-120.59	-121.45	-123.59	-124.72	-124.80
Representative Aliquot ID	NI10-09-6235J	NI10-06-6875H	NI09-03-6559F	NJ09-05-6711J	NK10-10-6974B	NK10-07-6273N
Mean Annual Wind Speed (m/s)	9.30	8.86	7.81	9.22	9.73	10.28
Min, Mean, Max Annual Significant Wave Height (m)	1.5/2.0/2.3	1.8/2.3/2.5	2.2/2.3/2.4	2.2/2.5/2.6	2.7/2.7/2.8	2.4/2.6/2.7
Min, Mean, Max Depth (meters) for Representative Aliquot	318/746/960	198/575/774	461/713/996	113/446/990	592/870/994	155/805/997
Construction Port	Port Hueneme, CA	Port Hueneme, CA	Port Hueneme, CA	Fields Landing, CA	Fields Landing, CA	Fields Landing, CA
Construction Port (Lat. Long)	(34.15,-119.2)	(34.15,-119.2)	(34.15,-119.2)	(40.72, -124.22)	(40.72, -124.22)	(40.72, -124.22)
Centroid Distance to Construction Port (straight line–km)	104	127	242	264	78	115
Centroid Distance to Construction Port (avoids land–km)	104	127	266	291	87	116
Operation and Maintenance (O&M) Port	Port Hueneme, CA	Port Hueneme, CA	Morro Bay, CA	Bodega Bay, CA	Fields Landing, CA	Crescent City, CA
O&M Port (Lat. Long)	(34.15,-119.2)	(34.15,-119.2)	(35.37, -120.86)	(38.33,-123.05)	(40.72, -124.22)	(41.75,-124.18)
Centroid Distance to Centroid Distance to O&M Port (straight line–km)	104	127	53	47	78	52
Centroid Distance to Centroid Distance to O&M Port (Avoids Land–km)	104	127	54	54	87	52
Interconnection Point	Goleta, CA	Goleta, CA	Diablo Canyon Nuclear Plant, CA	Jenner, CA (Hwy 116 and Hwy 1)	Eureka, CA	Crescent City, CA
Interconnection Point 1 (Lat. Long)	(34.43,-119.91)	(34.43,-119.91)	(35.21,-120.86)	(38.45,-123.13)	(40.74,-124.21)	(41.87,-124.21)
Centroid Distance to Interconnection 1 (Offshore Until Landfall) (Straight Line–km)	83	69	55	40	80	54
Centroid Distance to Interconnection 1 (Offshore Until Landfall) (Avoids Land–km)	101	69	55	40	87	54
Distance Point of Cable Landfall to Interconnect 1 (km)	6	6	5	5	5	5
Area (km^2)	753	445	1,234	799	431	1,752
Area (sq miles)	291	172	476	308	166	676
Total Potential Capacity (MW)	2,259	1,335	3,702	2,397	1,293	5,256

From Table 1, we located each site on the aliquot grid and calculated its area. Based on a nominal 3 MW/km^2, we estimated the wind energy capacity of each area.[16] For each area, a

[16] The nominal value of 3 MW/km^2 is used for broad calculations and reference to resource potential but is not recommended for detailed siting analysis.

representative aliquot was selected near the centroid of the area. This aliquot is identified using latitude and longitude coordinates. The physical characteristics of the representative aliquot were assumed to represent the average characteristics of the entire area. The white square on each map marks the location of the representative aliquot. The averaging effects of using the central aliquot rather than a comprehensive assessment of each wind turbine location is believed to be negligible relative to the resolution required for this analysis. This is reasonable because wind variations were found to be less than 1 m/s across each reference area, and energy production differences would tend to average out.

Distance from shore is a critical siting parameter for offshore wind as it is generally considered desirable to site turbines far enough from shore so they will not have a large visual impact. However, the required distance from shore is subjective and no minimum distance requirements have been assumed. Figure 13 shows the range of distances from shore for each of the six reference sites used in this report. Note that the 12-nm territorial sea boundary is indicated on the chart as a reference only.

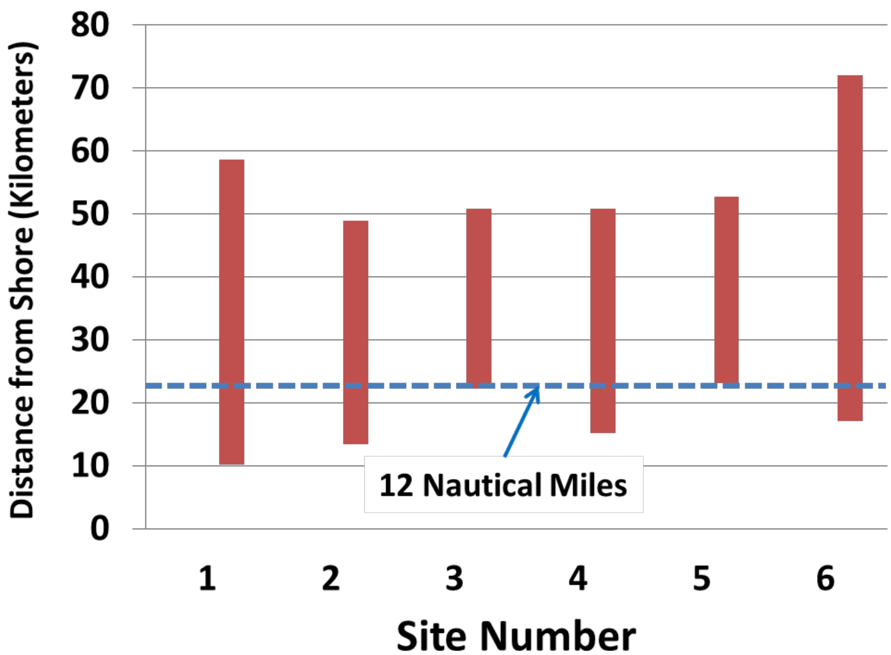

Figure 13. Distance from shore for six reference sites showing a range from minimum distance to maximum distance

Using publicly available information obtained from the California Energy Commission (CEC) on transmission lines and substations (California Energy Commission 2016), coastal interconnection points were identified and each reference area was assigned an interconnection point based on the closest viable electrical grid connections to the coast.[17] NREL assessed the distances to these interconnection points using straight line projections. These distances were used later to assess the cost of the electrical infrastructure.

The wave climate for each reference area was approximated using annual average information about meteorological ocean (metocean) conditions obtained from the marine and hydrokinetic (MHK) Atlas (NREL 2014). The wave climate was important in the cost evaluation as it is a key variable affecting construction weather windows and accessibility during operations (Beiter et al. 2016).

The construction and operation and maintenance (O&M) service ports that would likely be used from each of the reference areas were accessed from a GIS data layer developed to identify locations (World Port Index) and includes channel depth, degree of shelter, and access to an offshore resource area. In the United States, 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 of offshore wind power projects. Operations ports have relaxed channel depth and infrastructure requirements relative to construction ports. For this study, the primary criterion for port selection was to select the closest port to the reference area.

The average annual wind speed for each reference area was determined from a statistical long-term wind resource database obtained from AWS Truepower.

[17] Morro Bay is listed here as a potential O&M port, and may be considered in future studies for an interconnection point.

3 Offshore Wind Technology Assumptions

The time frame of this study extends through 2030 but focuses on three key years (commercial operation date [COD]) to assess progress and evaluate cost: 2015 (estimated from industry prototype data), 2022 (modeled), and 2027 (modeled). The primary technology assumptions are based on turbine size and floating platform technology, although there are many second-order technology assumptions that are explained in detail in Section 5.

From the depth distribution of the California technical offshore wind resource shown in Figure 3, approximately 96% of California's offshore wind resource is located in waters with depths greater than 60 m, indicating that floating wind technology should be considered as the primary technology option for large-scale offshore wind deployment in California.

To date, six single-turbine commercial-scale floating turbines have been deployed at various sites globally. However, the floating offshore wind market is growing rapidly. Five major projects are underway at various locations off Scotland, France, and Japan to install multi-turbine floating arrays, using 6- to 8-MW turbines with five different floating foundation designs. Some studies indicate that floating systems may reach cost parity with fixed-bottom offshore wind systems in future years (Beiter et al. 2016; Catapult 2015; James and Ros 2015).

Figure 14 illustrates three categories of floating wind turbine technology being developed. Each of these substructure types have evolved or been adapted from oil and gas production platforms.

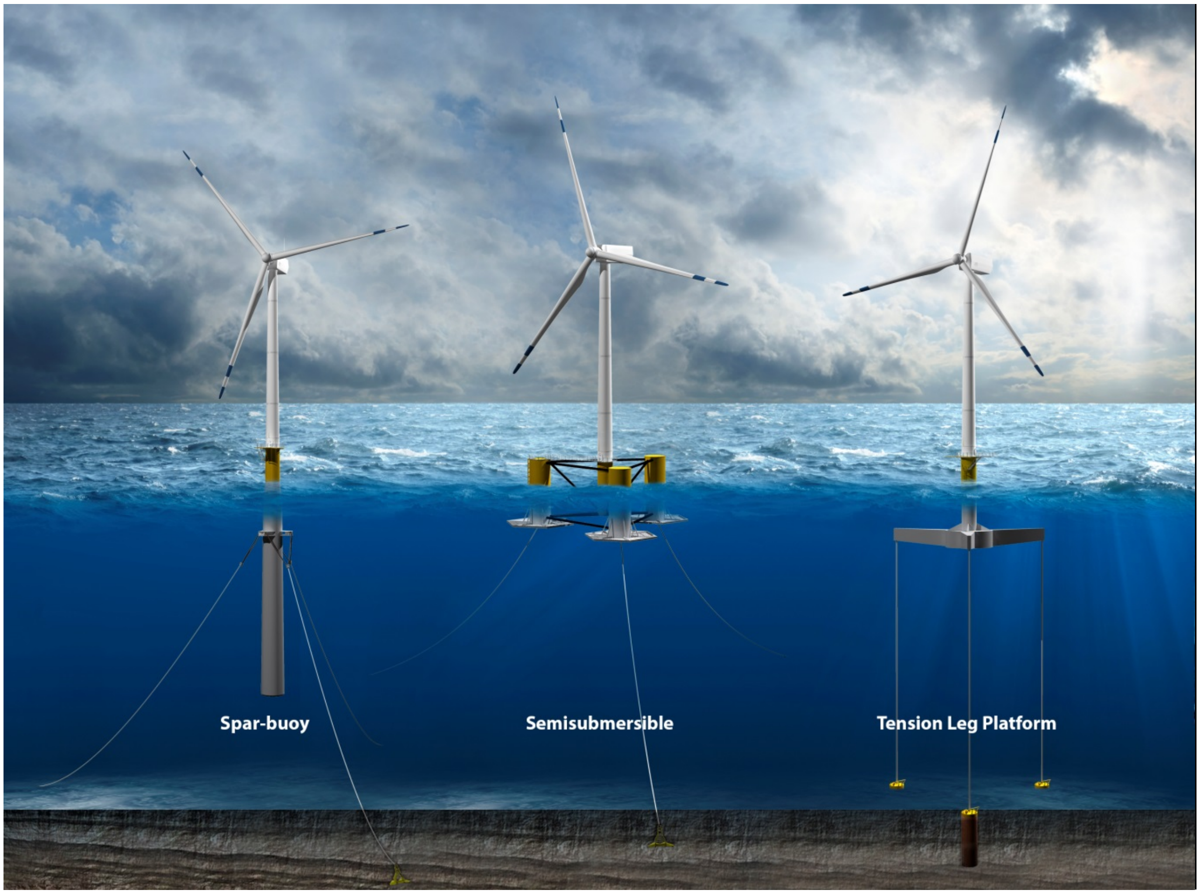

Figure 14. Substructure categories for floating offshore wind systems including the spar buoy, semisubmersible, and tension leg platform.
Illustration by Josh Bauer, NREL

The spar buoy is stabilized by ballast and has a deeper draft (i.e., penetrates farther below the water surface) that avoids surface wave action (Musial and Ram 2010). One promising variant of the spar buoy design relies on a center weight that can be secured near the surface to reduce draft depth during assembly and load-out and lowered at the project site for increased stability during operation (Stiesdal 2016). The semisubmersible is a floating substructure that can be deployed in water as shallow as 50 m. The semisubmersible design depends primarily on buoyancy and water plane area to maintain static stability, but it has the key advantages of being stable enough to support a wind turbine without mooring lines, and with a shallow draft that allows the structure to be towed fully assembled. Semisubmersibles allow assembly and maintenance to be performed at quayside rather than in the open ocean where more expensive vessels would be required. The tension leg platform gets its static stability from mooring-line tension. Therefore, it is generally unstable until the mooring lines are attached, and it can be difficult to deploy, but it is very stable once installed. Some new concepts are under development to make these systems more deployable.

All of these concepts have advantages and disadvantages. The optimum configuration for a given project may ultimately depend on site-specific variables such as bathymetry, soil conditions, and availability of vessels and infrastructure. All three classes of substructure foundations could be suitable for waters in and around California. Recent project applications submitted to BOEM in California and Hawaii propose to use the semisubmersible type foundation (BOEM 2016a; BOEM 2016b). Therefore, for the purposes of this study, the semisubmersible was chosen as the baseline technology option. It is important to note that this selection is not an endorsement of this technology type or a prediction that the current baseline configuration will achieve the lowest possible costs. We have also examined cost projections for several other proprietary concepts including the advanced spar buoy design described earlier (Stiesdal 2016). Although this design and others like it have not advanced to the prototype phase yet, preliminary engineering analysis conducted by Stiesdal indicates a potential for lower cost of energy than the baseline.[18] It is unknown which floating foundation design will achieve the best results. However, given recent declines in the cost of energy from fixed-bottom offshore wind projects, and the accelerated level of innovative floating foundation design work that is now underway, similar cost reductions to those seen in fixed-bottom foundation technology may be likely.

The other major technology driver for future cost analysis is the availability of larger turbines. Increasing turbine size has historically led to reduced balance-of-system (e.g., elements of the offshore wind plant not associated with the turbine) and O&M costs per megawatt. Recent industry cost declines can, in part, be attributed to the use of larger offshore wind turbines that are designed to operate in an offshore environment (Smith et al. 2015). Recent market data indicate that the trend toward larger machines is likely to continue into the future. Vestas has recently released its commercial 8-MW wind turbine to the offshore market with the first commercial deployments now underway (MHI-Vestas 2016). Announcements have already been made by Vestas and Siemens for 10-MW class turbines that are expected to be fully commercial by 2025 (Weston 2014; 2016). Based on NREL's engineering experience with turbine technology advancement and economic market trends, Table 2 describes the technology assumptions used for this study.

Table 2. Technology Assumptions for California Offshore Wind Cost Analysis

	2015 Technology	2022 Technology	2027 Technology
Turbine Rated Power (MW)	6	8	10
Turbine Rotor Diameter (m)	155	180	205
Turbine Hub Height (m)	100	112	125
Turbine Specific Power (W/m^2)	318	314	303
Substructure Technology	Semisubmersible	Semisubmersible	Semisubmersible

Table 2 assumes that by 2027 (COD), the industry could be able to deploy a 10-MW commercial wind turbine in large-scale projects in California. The table also describes more subtle trends

[18] See Stiesdal (2016), which projects LCOE of €50-100/MWh (about $55-110/MWh) for utility-scale projects completed in 2025 using the "TetraSpar" floating foundation design.

toward larger rotors and lower specific power ratings similar to the land-based market trends.[19] Tower height is expected to increase only enough to accommodate the longer blade lengths. Some scenarios assessed suggest that growth in turbine size could potentially be limited for fixed-bottom systems due to the lack of suitable turbine installation vessels (Beiter et al. 2016), but because floating turbines may use foundations such as semisubmersibles and spars that can be assembled in the construction ports or sheltered assembly areas and towed out to sea, this constraint was lifted for this study.[20] In other words, for this study it was assumed that developers can select the largest machines available without vessel constraints.

Power curves were created to represent the turbines sizes indicated in Table 2. These power curves are shown in Figure 15 with the respective data provided in Table D-1. The power curves were developed using the NREL Cost and Scaling model (Fingersh 2006) and assume that performance based on energy capture and average power coefficient will continue to improve incrementally over the next decade. The power curves embody typical features seen in all variable-speed pitch-controlled wind turbine power curves today. Cut-in wind speeds are reached around 4 m/s when the turbine begins to produce power. The power increases with wind speed until it reaches its rated power level at about 11 m/s.[21] At that point, the power production levels off and is regulated to maintain constant power until cut-out wind speed is reached at about 25 m/s. At cut-out, the turbine is automatically shut down by feathering the blades to zero power.

These power curves were corrected empirically in the shoulder region of the power curve, near rated power, to roll off more gradually, thereby representing actual behavior of turbine power curves. The 6-MW power curve was also adjusted to be slightly more aggressive in Region 2 (subrated power production below 11 m/s) by modifying the total conversion efficiency. These curves were validated by comparison with proprietary power curves from operating wind turbines (excepting 10 MW as there is no industry curve available). In general, we designed the power curves to be slightly more aggressive than current industry turbines by about 2% in overall energy production to anticipate the likely continuation of improvement trends to capacity factor and drivetrain efficiency that the industry has seen. However, the improvements we projected are considered minimal compared to historic advances in performance realized by land-based wind (Wiser 2016). The 10-MW power curve is theoretical because no 10-MW turbine exists yet, but the performance is modeled using a rotor diameter of 205 m, which reflects a lower specific power of 303 W/m^2 than offshore wind rotors of today. This estimation of declining specific power over time is reasonable given that many land-based turbines already exist with specific powers well below 300 W/m^2.

[19] A wind turbine's specific power is the ratio of its nameplate capacity rating to its rotor-swept area. All else being equal, a decline in specific power should lead to an increase in capacity factor.
[20] Semisubmersibles, spars, and tension leg platforms have different deployment protocols, with differing advantages and disadvantages (Beiter et al. 2016).
[21] The part of the power curve between cut-in and rated power is called Region 2. The part of the power curve where the pitch system is maintaining rated power is called Region 3.

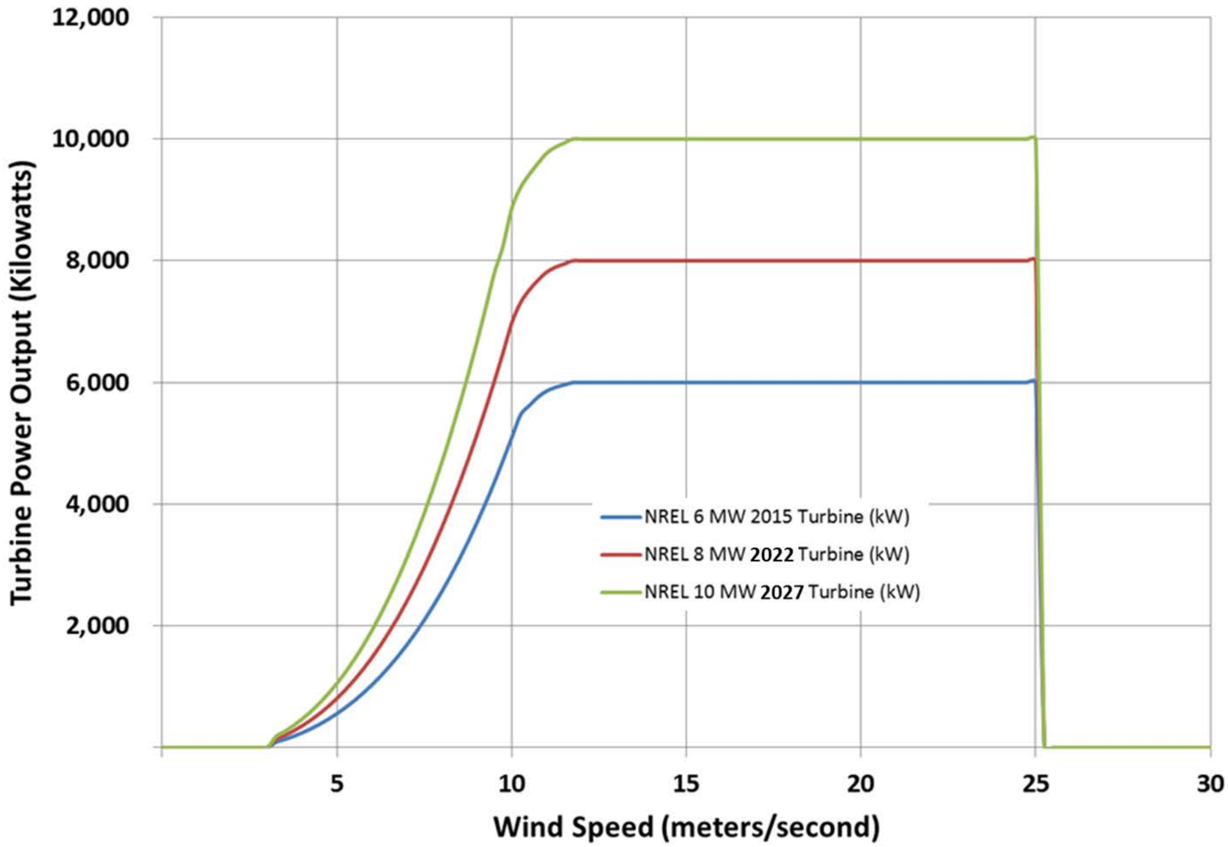

Figure 15. Offshore wind turbine power curves corresponding to 2015, 2022, and 2027; note 1 megawatt = 1,000 kilowatts

Assumed increases in annual energy production (AEP) as a result of future improvements are applied in 2022 and 2027. Improvements in swept-area-to-generator ratio, blade pitch control, improved array layout design, as well as turbine and wind plant optimization are applied to the baseline AEP estimates. The calculation of the baseline AEP is based on the performance of the assumed turbine technology and site-specific wind resource. Future advancements tend to increase the estimated capacity factors and AEP estimates.

One caveat in these AEP calculations is that they resulted in very high gross capacity factor estimates at some sites, which may not reflect an optimized system configuration. Typically, specific power ratings increase as average wind speeds increase because higher average wind speed sites tend to favor smaller rotors with higher nameplate ratings. This site-specific turbine design process is usually aimed at reducing loads (shorter blades) while increasing energy capture (higher nameplate rating), as the system optimization rewards higher nameplate ratings for sites where a large amount of time is at rated power. Additionally, sites with very strong wind resources, such as site 6, with an annual average wind speed of near 11m/s may require smaller rotors and larger generators depending on the site suitability. Thus, improvements in turbine-swept-area-to-generator ratio should be carefully considered depending on the strength of the wind resource, and the optimum technology selection would likely vary among the six sites. For this analysis, we assumed that the same turbine was deployed at all sites.

The assumed turbine technology already includes a small reduction in specific power that results in a 2.2% increase in AEP in addition to the aforementioned improvements in energy capture. Additionally, the increase in hub height from 100 m in 2015 to 125 m in 2027 also increases AEP by an additional 1.3%, but there is an additional cost because of the taller tower that is captured in the cost model.

4 Energy Production Estimates

4.1 Annual Energy Production Overview

To develop the cost analysis for the six reference sites, it was necessary to evaluate each site on the basis of how much electric energy it could produce. For the purposes of this cost analysis, the energy production of a single turbine is calculated for all six reference sites individually. Energy production was determined by calculating hourly power production using a synthetic wind speed time series with the same statistical characteristics as the aliquot closest to the centroid of each site (see Table 1). Turbines were assumed to be arranged in 600-MW array layouts to determine losses and assess total capital costs.[22]

4.2 Hourly Geodatabase

A geodatabase of hourly wind speed data was created from the 17-year statistical AWS Truepower database by aggregating this statistical record of wind speed data with time-varying wind speed data from the National Aeronautics and Space Administration's Modern-Era Retrospective Analysis (MERRA) data (AWS Truepower 2012; NASA 2016). The resulting hybrid data set captures MERRA's time-varying component while maintaining the exact statistics of the long-term AWS Truepower record. The process of merging and validating these data is illustrated in Figure 16.

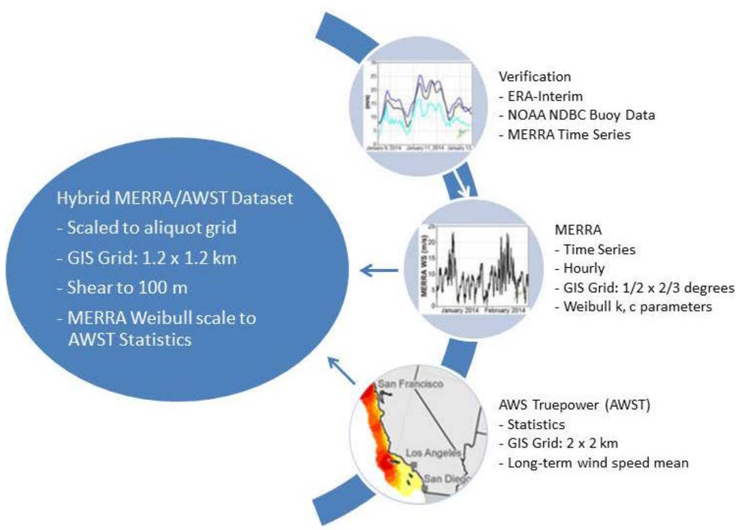

Figure 16. Process of creating the geodatabase of hourly wind speed[23]

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[22] The 600-MW array size is large based on historic market data but was chosen to reflect a conservative layout for wake loss assessment and a trend toward larger arrays that may correspond with future development.

[23] The effort to merge these two databases was funded by BOEM under an interagency agreement between BOEM and NREL in 2015.

4.3 Diurnal and Monthly Single Turbine Characteristics

From the hybrid data set described above, the average diurnal power output of a single turbine was calculated for each of the six reference sites. These data are shown in Figure 17 for the month of March.

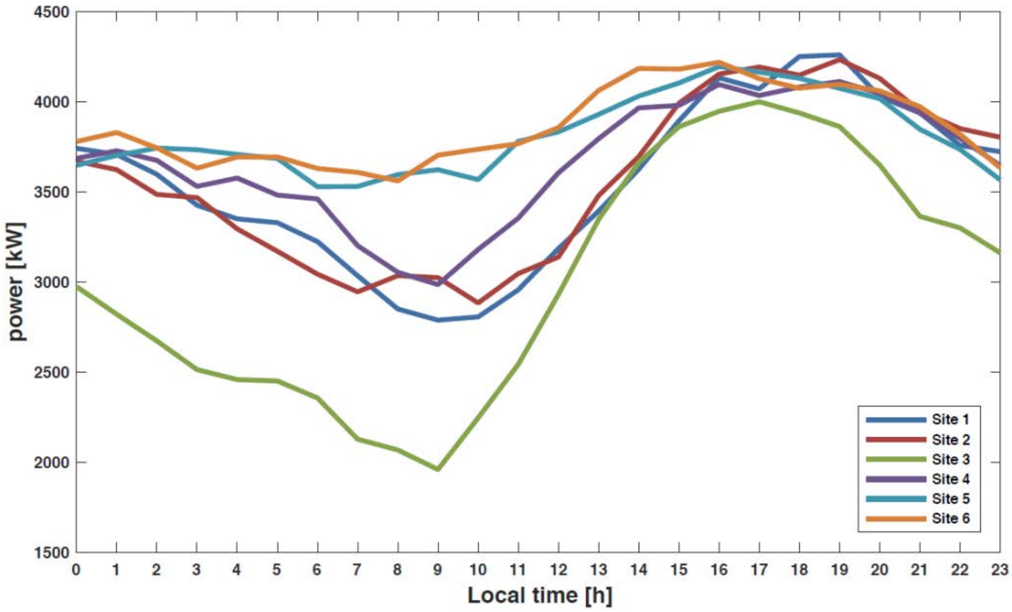

Figure 17. Diurnal power output for a single 6-MW offshore wind turbine in the sample month of March

Figure 17 illustrates the similarities between all of the California coastal sites considered in this report for the month of March. March was chosen because it is often used to illustrate the "Duck Curve" by the California Independent System Operator (Gilman et al. 2016). Although the average wind speeds vary from site to site, there is a strong correlation across all six reference sites with the time of day. The sites south of San Francisco tend to reach their daily peak about an hour later than the sites north of San Francisco, but all sites show a tendency to peak between 5 p.m. and 7 p.m.

Figure 18 shows how the monthly average power would change among the six reference sites over a 12-month period.

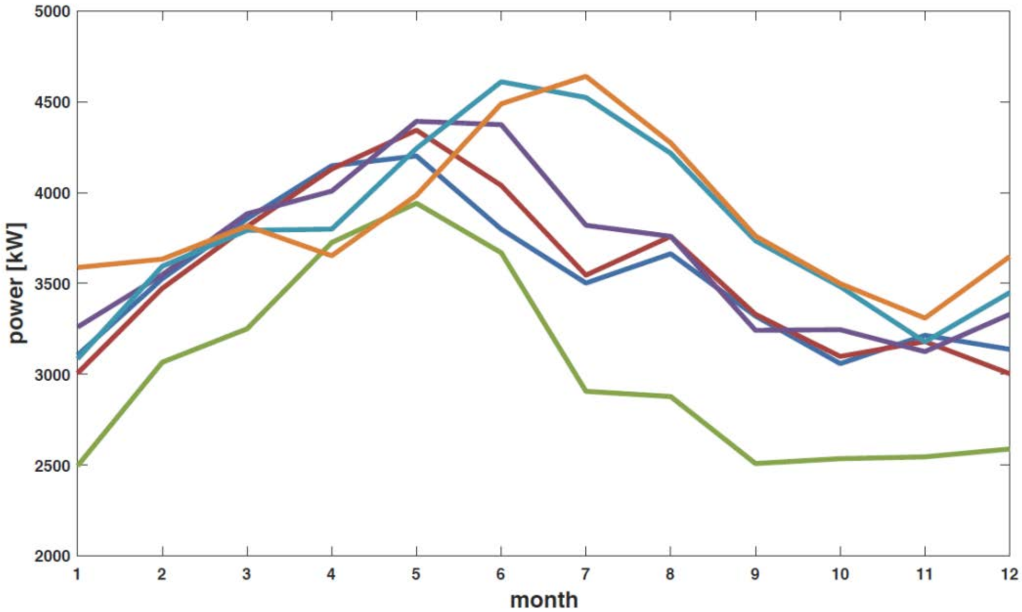

Figure 18. Average monthly power output for a single 6-MW offshore wind turbine at six California offshore reference sites (starting with month 1 [January])[24]

The chart shows that all sites have peak power between May and July, with the southern sites characteristically showing earlier peak power in May, whereas the northern sites are characterized by a later peak power in July. Site 4 near Bodega Bay shows a pattern that is in between May and July with respect to its peak. For more details on diurnal power production for all six sites, see Appendix B.

4.4 Long-Term Wind Resource Calculations

To obtain accurate estimates of AEP, Weibull wind speed statistics, diurnal wind variations, and monthly wind characteristics for the representative aliquot of each site were run through the Windographer software package developed by AWS Truepower (AWS Truepower 2016). Windographer is a commercial software program for analyzing wind resource data. It imports data commonly encountered in the wind power industry, allows rapid quality control and statistical analyses including measure-correlate-predict, a technique for predicting long-term wind resources. It also includes visualization tools for graphical interpretation. Windographer's data synthesizer was used to generate 8,760-hourly wind speed time series that have the same statistics as the hybrid MERRA-AWS data set. For each given site, these statistics include distributions that contain long-term (17 years) characteristics of the wind resource as represented by the mean, maximum, minimum, and standard deviation of wind speed, as well as the distribution of the wind speed on various timescales (long term, monthly, hourly, and hourly by month), represented by the Weibull parameters.

[24] The effort to merge these two databases was funded by BOEM under an interagency agreement between BOEM and NREL in 2015.

The 8,760-time series match the distribution, diurnal, and seasonal patterns and the autocorrelation of the hybrid MERRA-AWS data set. The 8,760 site-specific time series were fed into the 6-, 8-, and 10-MW turbine power curves (shown in Figure 15) to estimate gross AEP and gross capacity factor for each of the target technology years, 2015, 2022, and 2027, respectively.

The gross AEP was calculated for an entire 600-MW wind plant in each technology year. The gross AEP is defined as the energy that the wind plant would produce at a given site without losses and is based only on the power curves in Figure 15 and the wind speed time series generated by Windographer. The sum of the energy produced by a single turbine for each hour of the 8,760 time series was multiplied by the number of turbines in the 600-MW array for the technology year.[25] The gross capacity factor was calculated by dividing the gross AEP by the maximum power that the 600-MW plant could produce. These values are shown in Figure 19 for each of the technology years, respectively. Net AEP is determined by applying the loss assumptions to the gross AEP. This accounts for the reduction in power delivery to the grid as a result of site conditions and wind plant inefficiencies. Net AEP can be thought of as the energy delivered to the grid. NCF is the net AEP divided by the maximum energy the wind plant can produce, and running steady at rated power, without considering losses.

4.5 Loss Assumptions

Total loss estimates for COD years 2015, 2022, and 2027 are provided in Figure 19. Losses account for differences between the annual output of the turbines operating at the site without obstruction and the electricity delivered to the grid. Environmental losses include energy lost because of surface roughness created by ice on the blades, lightning damage, or shutdowns caused by extreme temperatures. Technical losses include inefficiencies caused by issues such as drivetrain wear or pitch system imbalance. Site-specific losses include array energy lost as a result of turbines operating in the wake of other turbines, electrical losses due to the transmission of the electricity in the array and to shore, and turbine availability issues that are driven by accessibility limitations caused by the wave environment as well as general turbine reliability.

Losses were generally assessed using standard industry assumptions (AWS Truepower 2014). For this analysis, losses were divided into generic and site-specific losses. Generic losses were held constant for all sites and over time. Site-specific losses varied among the reference sites. The loss percentages were applied to the gross AEP to compute the net AEP for the cost models (Figure 20 and Figure 21) for each reference year (2015, 2022, and 2027).

4.5.1 Generic Losses

The generic losses include 1% for energy lost as a result of icing or blade soiling, which can be more significant in land-based applications. The 1% loss may be high for offshore sites in California where ice or soiling accumulations on blades would be extremely rare. In addition,

[25] For instance, for 2015 there were 100 6-MW turbines, for 2022 there were 75 8-MW turbines, and for 2027 there were 60 10-MW turbines.

generic losses include 0.5% for low/high temperature shutdowns, 0.1% for lightning losses, 1% losses as a result of hysteresis, 0.1% for on-board equipment (parasitic load), and 0.1% for rotor misalignment loss across all turbines. These industry numbers should be further assessed in actual AEP calculations but are considered representative for this report.

4.5.2 Site-Specific Losses

The site-specific losses included wake losses, electrical losses, and availability losses. Each was calculated for the spatial conditions at each reference site (e.g., electrical losses varies with distance to the grid interconnect and water depth).

Wake losses for the 6-MW wind turbine array were computed in an earlier study using the NREL Offshore Wind Cost Model (Beiter et al. 2016). Wake losses were calculated for the entire United States offshore wind resource area using Openwind, a software program developed by AWS Truepower (AWS Truepower 2010). For this analysis, we used these wake loss results for the California Outer Continental Shelf for the initial 6-MW turbine array. As described by Beiter et al. (2016), turbines were arranged in 10-by-10 arrays with 7- rotor diameter (D) spacing[26] to determine the wake losses. The analysis did not consider alternative array configurations that may lower losses further at each site. As such, these 10-by-10 estimates may overstate losses because more efficient array layouts may exist. For future years, the 2015 loss assumptions were modified to account for reduced losses as technology improves as a result of fewer turbines, better siting tools, and active wind plant wake control strategies that are under development.

Electrical losses were based on equations developed under the recent electric parameter study that is now part of the NREL Offshore Wind Cost Model (Beiter et al. 2016; Musial et al. 2016). Electrical losses vary as a function of distance to shore and water depth because of different requirements for cable length. As fewer turbines are deployed because of increases in turbine size, the electrical losses decline slightly because the total length of array cables is reduced.

Availability losses are site-dependent but are particularly severe in the California wave climate relative to other parts of the United States. These conditions likely hinder normal O&M activities initially. Therefore, turbine availability is likely to be lower at first (Beiter et al. 2016). Over time, new O&M strategies for turbine access are likely to mitigate turbine access issues and help restore availability to more normal industry values (Beiter et al. 2016).

[26] Rotor diameter is typically used as the primary measure for turbine separation in an array. 7D spacing means that there are 7 rotor diameters of distance between towers. For example, the 6-MW turbine has a diameter of 155 m, which means that there would be (7 x 155 or) 1,085 meters of distance between towers.

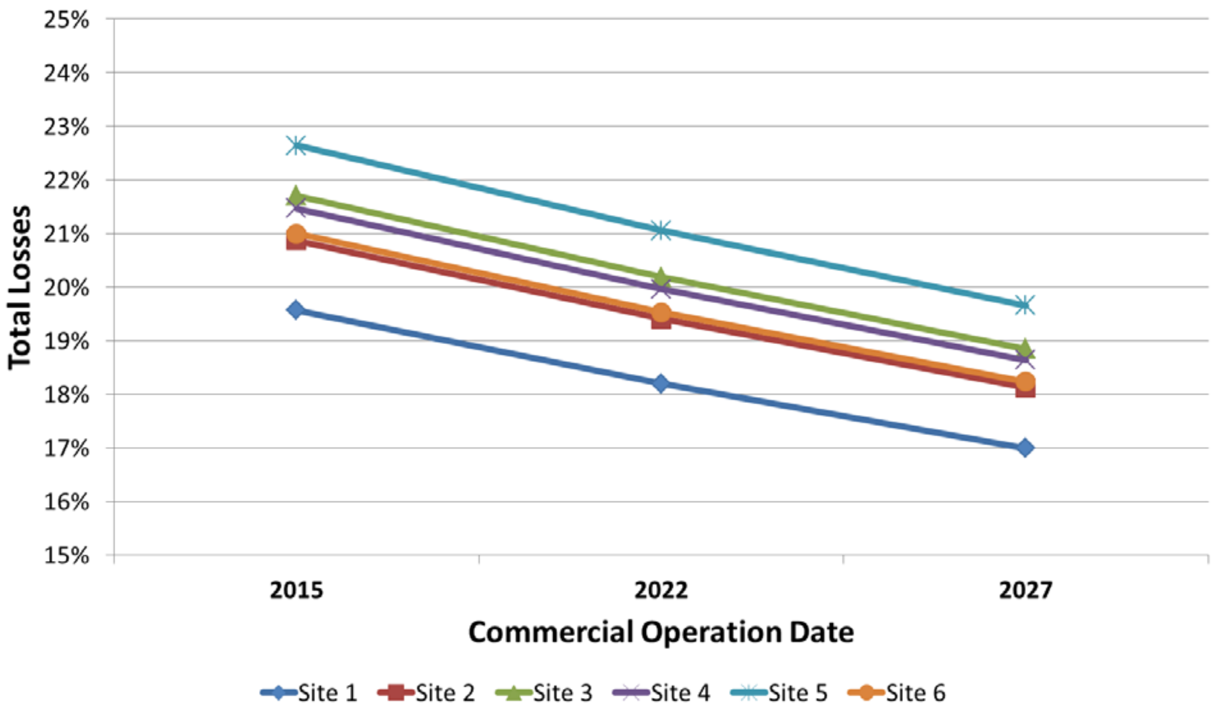

Figure 19. Estimated total losses from 2015 to 2027 (COD)

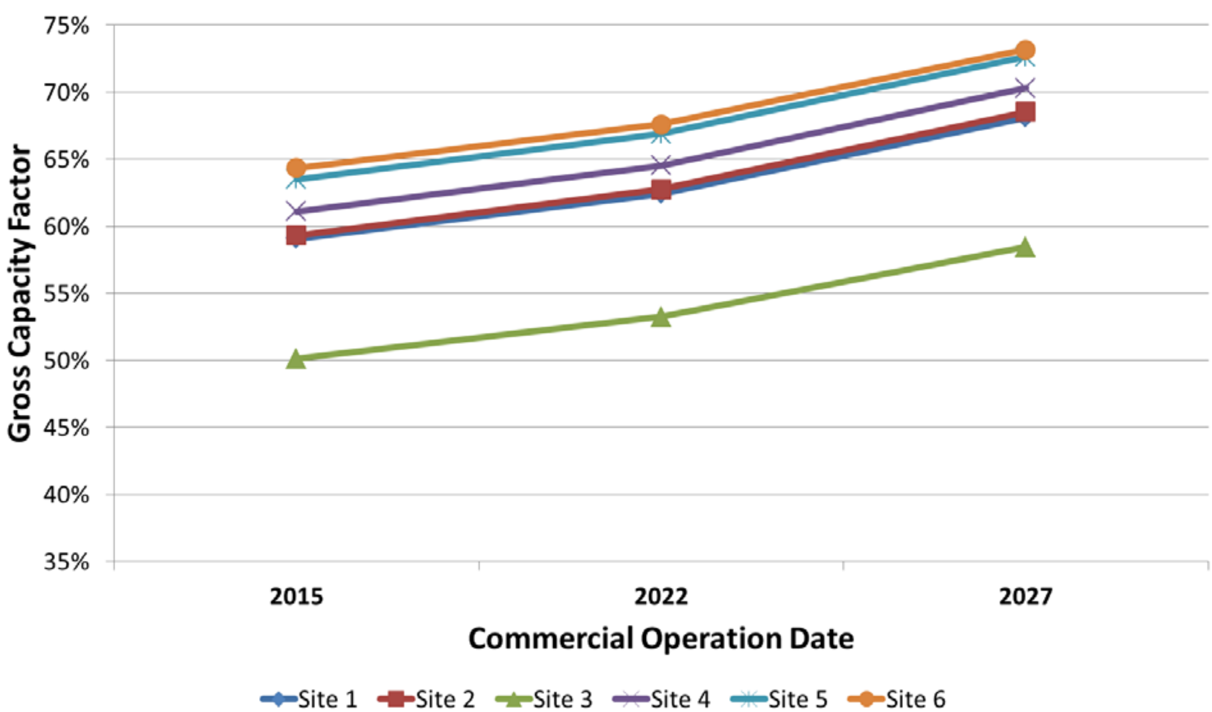

Figure 20. Estimated gross capacity factors

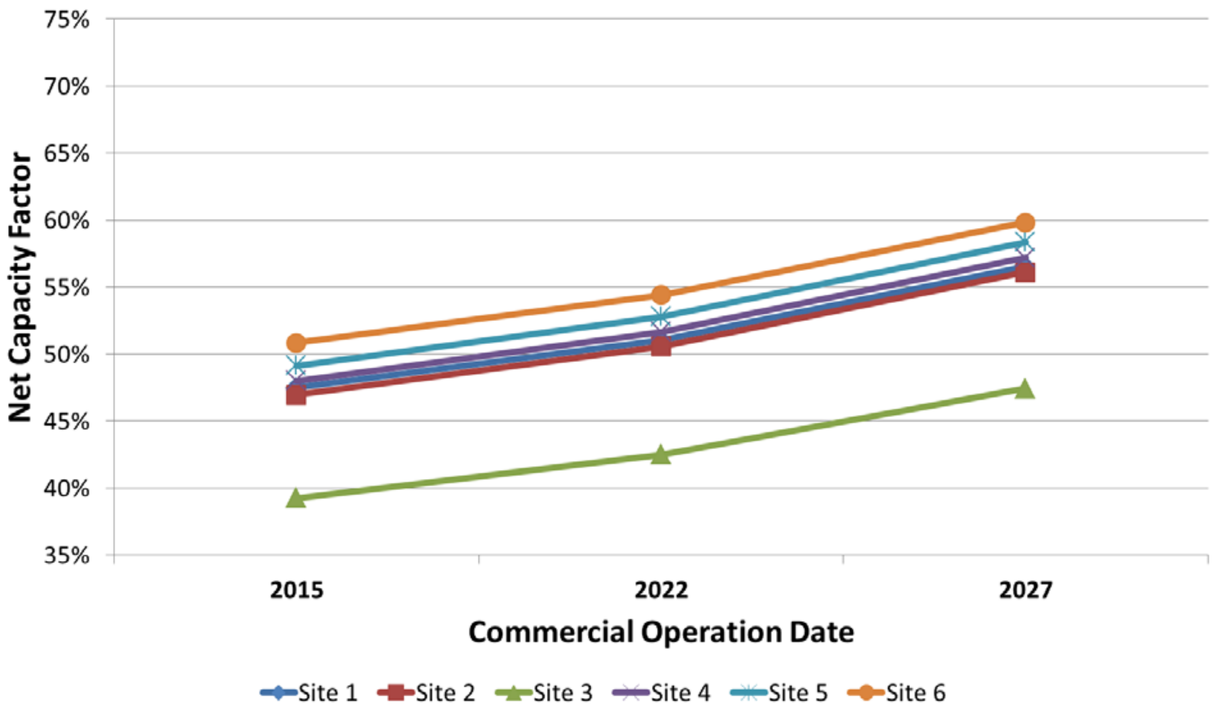

Figure 21. Estimated net capacity factors

4.6 Representative Reference Offshore Wind Areas

To simplify the cost analysis, two representative sites were chosen to be carried forward for further cost analysis. As noted earlier, there are many similarities between the six sites along the coast from the Channel Islands to the Oregon border. Diurnal characteristics are similar for all sites examined for most months of the year with only small variations in the occurrence of average peak wind and seasonal peak averages. These data were shown in Figure 17 and Figure 18. Wind speeds vary among sites but site-selection criteria gave preference to the highest wind speed sites 1-3 in the southern region because they exhibit characteristics that are very similar in terms of seasonal and diurnal peaks. Based on those similarities, site 2 was chosen as a proxy to represent both site 1 and 3. Using the same logic, site 5 was chosen to be a proxy to represent site 4 and 6. As such, sites 2 and 5 (Channel Islands North and Humboldt Bay Area, respectively) were chosen to carry forward into the detailed cost assessment.

5 Wind Power Plant Cost Modeling

Sections 2, 3, and 4 of this report provide an overview of the site-selection process, offshore wind technology assumptions, and available energy production for the locations considered in this study. NREL's Offshore Wind Cost Model is applied in this analysis to assess reference areas 2 and 5 identified in Section 4. This section provides details about the model, its underlying spatial cost relationships, and assumptions.

NREL's Offshore Wind Cost Model follows the general definition of LCOE described in Beiter et al. (2016):

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

where:

FCR = fixed charge rate (%)
CapEx = capital expenditures ($/kW)
AEP_{net} = net average annual energy production (kWh/yr)
OpEx = average annual operational expenditures ($/kW/yr).

To simplify the calculation of LCOE for the purpose of this study, cost elements are divided 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 available information 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. Nevertheless, 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 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 other items. For instance, engineering and management costs incurred from financial close through commercial operations are applied as a percentage of capital expenditures (CapEx).

Further details about the bottom-up method for calculating CapEx, operational expenditures (OpEx), and AEP from spatial parameters and financial parameters such as the fixed charge rate

(FCR)[27] are documented in Beiter et al. (2016). The assumptions and relationships developed for these cost categories are discussed in Section 5.2.

5.1 NREL's Offshore Wind Cost Model

NREL's Offshore Wind Cost Model was developed to quantify the impact of key spatial parameters and cost-reduction pathways on the LCOE of potential fixed-bottom and floating locations across the U.S. offshore wind resource area between 2015 and 2030 (COD). The methodology and findings of the model are documented in Beiter et al. (2016). It combines data and assumptions from a variety of sources, including market reports (e.g., Smith, Stehly, and Musial [2015]; Moné et al. [2015]; Maness and Maples [forthcoming]), cost-reduction pathway studies (e.g., Valpy et al. [2014]; Catapult [2015]; E.C. Harris [2012]; The Crown Estate [2012, 2015]), spatial data layers, and industry collaboration. In estimating costs, NREL defines a scenario for the Offshore Wind Cost Model that assumes 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 (Beiter et al. 2016).[28] These general assumptions also apply to this analysis focused on California.

For this analysis, we used the Offshore Wind Cost model, its assumptions, spatial cost relationships, and cost-reduction pathways to estimate floating offshore wind costs for the two representative areas identified in Section 4. In estimating costs, the following steps were completed:

1. Identify two representative areas for potential floating wind technology development and characterize the spatial conditions at these locations (Section 2)
2. Calculate the potential energy production at each representative offshore wind area, including an estimation of expected losses (Section 4)
3. Define floating offshore wind technology assumptions (e.g., foundation size and configuration, expected turbine and platform configurations [Section 3]) for the three focus years, 2015, 2022, and 2027 (COD)[29]
4. Estimate LCOE for the three focus years 2015, 2022, and 2027 (COD) by populating NREL's Offshore Wind Cost Model with the spatial characteristics of the representative offshore wind areas (step 1), their calculated energy production, and expected loss

[27] The fixed charge rate is used to approximate the average annual payment required to cover the carrying charges on an investment and tax obligations.
[28] An analysis of alternative scenarios is outside the scope of this report. One way to quantify LCOE with smaller domestic content may be to factor in transportation costs for different shares of imported turbine components and services; alternatively, domestic deployment trajectories needed to support the assumed cost reductions could be estimated.
[29] These three focus years (indicated in terms of COD) were chosen to remain consistent with Beiter et al. 2016.

estimates (step 2) under the defined offshore wind floating technology assumptions (step 3)

5. Extrapolate the data to 2030 (COD) using the modeled cost data and generate modeling output for the time period 2015–2030 in the form of tables and graphs.

A summary of the methods and assumptions applied in steps 4 and 5 of this process are described in Section 5.2.

5.2 Costs

The NREL Offshore Wind Model is based on an assessment of a generic 6-MW floating offshore wind turbine and scaling relationships developed for the Beiter et al. (2016) assessment. As shown in Table 2, in the scenario assumed for this analysis, a 6-MW floating turbine size corresponds to focus year 2015 (COD), an 8-MW floating turbine size to focus year 2022 (COD), and a 10-MW floating turbine size to focus year 2027 (COD). Because the Beiter et al. (2016) assessment assumes a different scenario in terms of the growth of turbine size over time (i.e., 3.4 MW for 2015, 6 MW for 2022, and 10 MW for 2027), values were adjusted in this report to correspond to the modified turbine growth trajectory used in this assessment. For this analysis, we assumed a 600-MW wind farm size. All costs, unless otherwise noted, are represented in U.S. 2015 dollars (USD).

Table 3 shows the estimated values of the floating cost reduction scenario from Beiter et al. (2016) adjusted to the turbine growth scenario chosen for this study (Table 3) for major LCOE categories that are associated with offshore wind power projects: fixed costs, variable costs, and cost multipliers.

Table 3. Cost Categories for Spatial-Economic Assessment

Cost Category	Type	Cost ($/kW)[a]	Comments
Turbine	CapEx	$1,583	NREL-modeled, generic 6-MW turbine
Ports and Staging	CapEx	$42	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
Development	CapEx	Multiplier	Four-percent multiplier of turbine CapEx and balance- of-system CapEx
Engineering and Management	CapEx	Multiplier	Multiplier of 3.5% applied to fixed and variable CapEx
Insurance	CapEx	Multiplier	Multiplier of 1% applied to fixed and variable CapEx
Commissioning	CapEx	Multiplier	Multiplier of 1% applied to fixed and variable CapEx

Cost Category	Type	Cost ($/kW)[a]	Comments
Contingency	CapEx	Multiplier	Thirty percent of installation CapEx; 5% of other CapEx
Construction Insurance	CapEx	Multiplier	Multiplier of 1% applied to fixed and 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	Sixty-five percent of installation CapEx
Fixed Charge Rate (FCR)	CapEx	Multiplier	10.51%

[a] All dollars are reported in USD (2015), if not indicated otherwise. Adapted from Beiter et al. (2016) to correspond to 6 MW in 2015 (COD)

5.2.1 Fixed Costs

The fixed-cost category encompasses the cost items that do not have clear, empirical linkages to spatial parameters based on available information 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.

Turbine Capital Expenditures

This assessment is based on an NREL-modeled, generic 6-MW offshore wind turbine. It is estimated that a 100-unit order in 2015 (COD) would be priced at approximately $9.5 million per turbine or $1,583 per 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. In contrast to the cost assessment in Beiter et al. (2016), a 6-MW turbine size is assumed for the two representative offshore wind areas in California to be available and prevalent in the market by 2015 (COD); an 8-MW turbine by 2022 (COD); and a 10-MW turbine by 2027 (COD). The turbine capital costs for the 8-MW (2022 COD) and 10-MW (2027 COD) turbine sizes were derived based on estimated costs for the generic 6-MW NREL turbine and scaling relationships from The Crown Estate (2012).

As described in Beiter et al. (2016), this assessment assumes that wind turbine supply agreement prices are independent of the physical characteristics of a given project site. 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 specific to the two offshore wind areas in California. Based on recent market activity, we assume that turbine original equipment manufacturers will initially fabricate wind turbine components at European facilities and ship them to U.S project sites. This situation is assumed to change as the U.S. market matures and as projects emerge in regions that are logistically difficult to reach from Europe. For instance, it may be more cost-effective for offshore wind areas in California to procure wind turbine components in Asia. In addition, subject to market outlook, turbine original equipment manufacturers may build new fabrication facilities domestically 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 does not capture variability in turbine transportation costs.

Development

Development costs for offshore wind power projects can be segmented into four main categories: engineering, permitting, site characterization, and decommissioning. Engineering costs include a prefront-end engineering design study to inform permitting applications. A full study of this nature is typically conducted to inform procurement. 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,[30] and ocean data. The decommissioning assessment generally includes detailed analyses to estimate all costs associated with returning the project site to its original state. The party responsible for decommissioning is specified in the original site lease. Decommissioning responsibility will be transferred if a change of ownership takes place. Specific conditions for decommissioning will be set by the leasing authority but are expected to follow the above principle. Although these costs are generally 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.

Consistent with Beiter et al. (2016), we estimate that the development costs for a 600-MW project would amount to approximately $110 million, or $183/kW in 2015 (COD) 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 no clear relationship between physical site conditions and development costs.

Ports 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 and equipment, and port fees incurred by installation vessels (e.g., entrance/exit, dockage,

[30] 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.

loading/unloading). Essentially, this cost category represents assembly activities that occur on land or at the quayside. It is 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 relatively small impact of ports on LCOE and the difficulties of accurately predicting costs. These costs were derived based on NREL's Offshore BOS Cost Model, documented in Maness and Maples (2016).

It is expected that ports in California will require upgrades to support industrial-scale offshore wind deployment. For the purpose of this study, it is assumed that appropriate port facilities and capacity would be available to support the construction and operation of the representative sites chosen for this study. Accurately identifying the cost of these upgrades would require a detailed analysis of each individual port, which is beyond the scope of this analysis. The allocation of financial responsibility for these capital improvements is also unclear and might vary from one project to another (e.g., federal, state, and/or local government agencies may be able to fund some port improvements to attract economic development).

5.2.2 Variable Costs

Variable cost components as defined for this analysis have distinct relationships with spatial parameters. A series of parameter studies were conducted to derive these variable cost relationships and are summarized in this section. A detailed description of the methodology and assumption applied to derive these relationships is documented in Beiter et al. (2016).

Substructure Parameter Study

This parameter study conducted in Beiter et al. (2016) focuses on the relationship between primary substructure component costs and a combination of environmental (water depth, metocean, and seabed soil conditions) and turbine size parameters. Although the Beiter et al. (2016) assessment considered both semisubmersible and spar buoy substructures, this analysis applies semisubmersible substructures only.

For determining these relationships, nine representative sites across the United States were considered using NREL's Floater Sizing Tool (FST) (Beiter et al. 2016). This tool was developed based on oil and gas industry experience in the United States. The FST assessment determined the minimal overall floating substructure mass in water depths of 40 m–1,000 m for a range of subcomponents, considering the fabrication complexity of each (Table 4). We estimated that the total mass of the floating substructures for specific turbine sizes had significantly greater dependency on environmental conditions than on water depth at a given site. The resulting masses are not shown because some information was provided under confidentiality agreements, but in a second step, the mass relationships were converted into costs. The relationships between mass and environmental conditions and turbine size were combined with steel fabrication costs provided by a fabricator in the Gulf of Mexico region. The resulting steel fabrication subcomponent costs in dollars per tonne are shown in Table 4.

Table 4. Floating Subcomponent Costs

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

Similar methods were also used to develop cost estimates for the procurement of both drag embedment anchors and suction pile anchors dependent on seabed soil conditions (following the Folk classification). Because the FST is based on oil and gas project development experience, it is expected that large production quantities, such as the 600-MW deployment scenario assumed for this analysis, are associated with additional cost savings because most oil and gas platforms are typically fabricated as single units rather than in large volume orders (Beiter et al. 2016).

More details on the derivation of the substructure costs are documented in Beiter et al. (2016).

Electrical Infrastructure Parameter Study

For the electrical infrastructure parameter study documented in Beiter et al. (2016), a relationship between electrical system component costs and spatial parameters (i.e., water depth and distance to point of cable landfall) was developed. This study was based on the generic plant layout of 100 6-MW turbines. The electrical system was divided into the following components (see Figure 22):

- 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.[31] It includes:
    - A high-voltage alternating current (HVAC) offshore substation and, if applicable, an HVDC converter terminal platform[32]
    - High-voltage submarine cables (including cable landing)
    - A land-based substation, and, if applicable, HVDC converter terminal platform.

[31] Note that some technology that would be required to export power from floating offshore wind projects has not yet been commercially proven. Notable examples include 220-kV HVAC and 320-kV HVDC power cables. This analysis assumes that this technology will mature to meet demand as floating offshore wind technology matures.
[32] It is worth noting that transmission innovations to modularize the substation technology that distributes electronics to turbine foundations could bring electric infrastructure costs down in the future.

- 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.

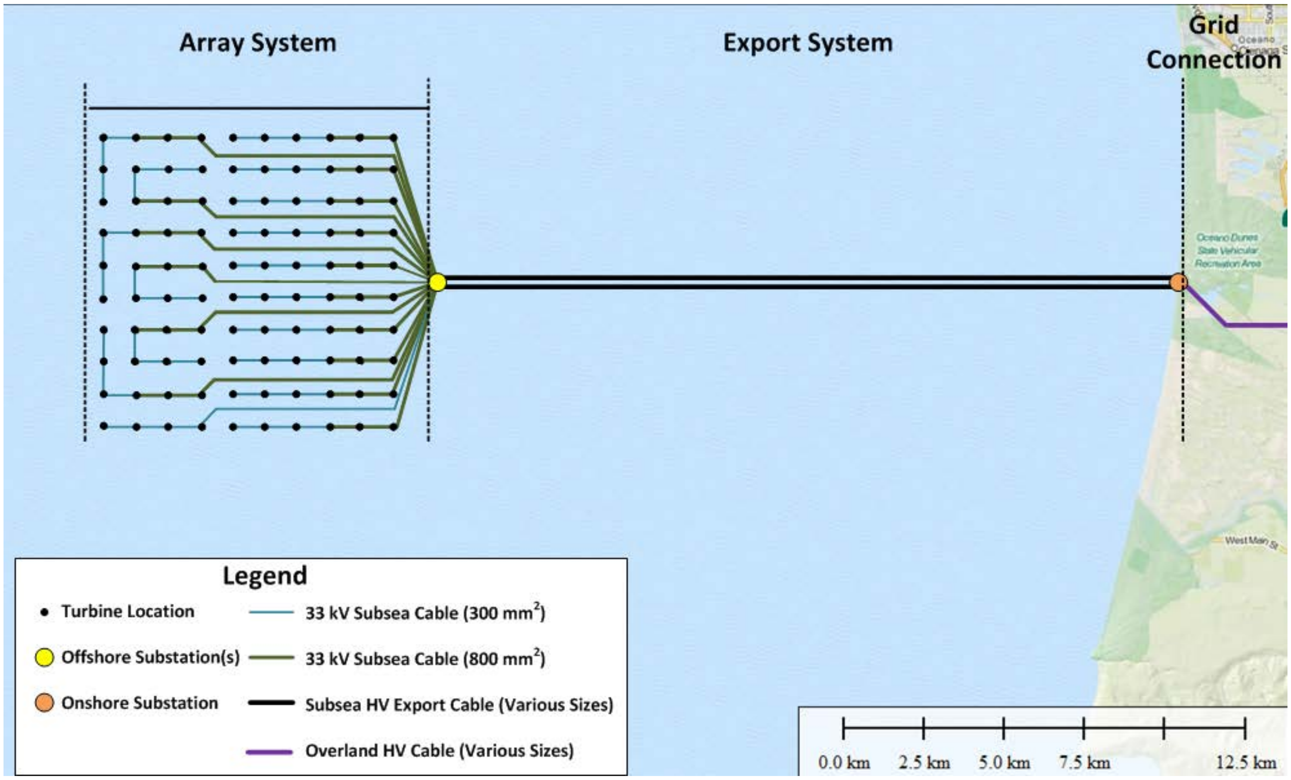

Figure 22. Schematic of modeled array cable layout and electrical export cable system

Source: Reprinted from Beiter et al. (2016)

Structural modeling of the array cables to evaluate how floating dynamic cable configurations would perform with respect to strength and fatigue was not in the scope of this assessment. Instead, a simple, geometric method was used to reasonably approximate the relationship between the array cable system length and water depth. Based on a water depth of 575 m (site 1) and 870 m (site 2) (Table1), factors for procurement and installation costs were applied to the various quantities of cable.

The distance between the floating offshore wind project and land-based substation has 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. Normally, high-voltage options are used for the export cable to minimize transmission losses. Lower voltages can be used when projects are very close to shore but would not be practical for the reference sites in this study. 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 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. Figure 23 shows the optimal choice of export system dependent on the distance from the sites to cable landfall. With the centroids of site 2 and site 5 estimated to be located 69 km (site 2) and 87 km (site 5) from the point of cable landfall, this analysis chose a 220-kV HVAC as the cost-optimal export system.

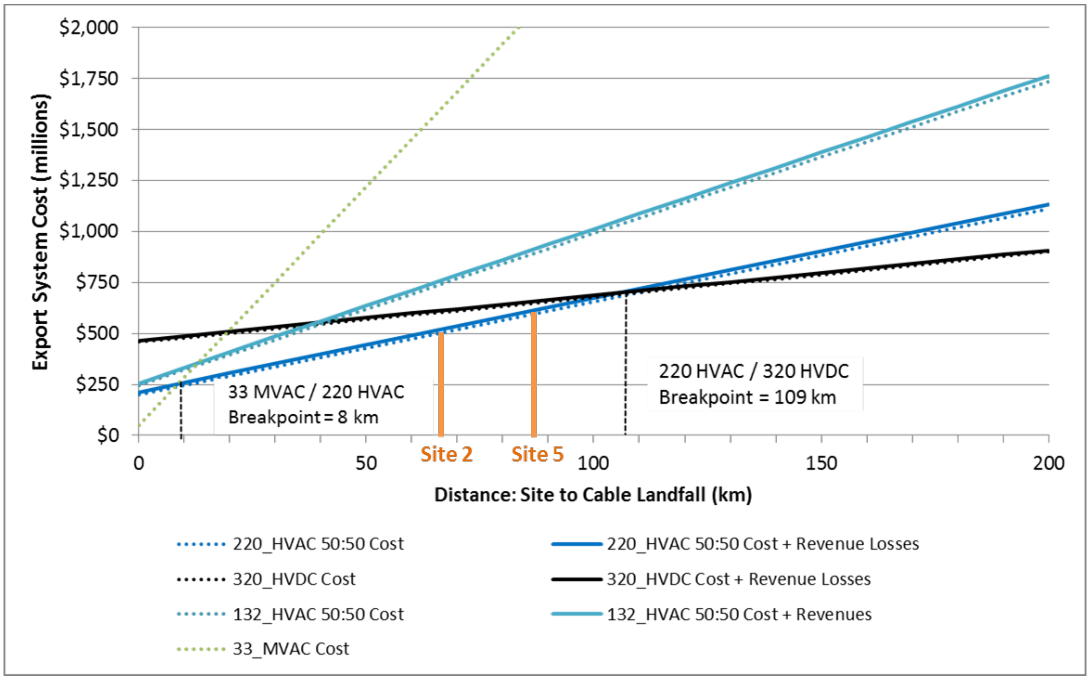

Figure 23. Summary of export system costs with distance from shore showing the two reference sites (Source: Adapted from Beiter et al. [2016])

The distance from cable landfall to the interconnection for the two representative California sites is based on a site-specific assessment and shown in Section 2. The two representative sites are assumed to connect through an underground cable from the point of cable landfall to the interconnection.

Further information on the electrical infrastructure is documented in Beiter et al. (2016).

Installation Parameter Study

The installation parameter study from Beiter et al. (2016) analyzed the scaling of installation costs with substructure type, turbine nameplate rating and size, and spatial parameters (distance from project site to staging port, metocean conditions).[33] The installation parameter study was performed using NREL's Offshore BOS Cost Model (Maness and Maples forthcoming).

[33] 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 5.2.2).

The semisubmersible substructure is assumed to be 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 is assumed to take 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.

NREL's Offshore BOS Cost Model (Maness and Maples forthcoming) was used to develop curves that relate the installation costs for the semisubmersible substructure and corresponding installation strategy to key spatial and technical parameters. The key parameters covered in this report include logistical distances, which are relevant for the transportation of components, and include the distances from the staging port to the project site; the water depth, which is a driver of substructure size and mooring line length for floating substructures as well as installation vessel selection; and the turbine size, which also drives the substructure size and mooring line requirements. Distance bounds were set from 50 km to 500 km from the relevant node (either staging port or assembly area). Water depths ranged from 66 m to 1,000 m. The turbines analyzed in this study were 6 MW, 8 MW, and 10 MW in size. Parameterizations were performed for each of the three sizes considering the logistical distances and the water depth parameters. Table 5 shows a breakout of the parameter ranges and increments considered in this study.

Table 5. Key Parameter Ranges

Variable	Semisubmersible Floating Substructure
Water Depth	66 m–1,000 m, varying increments
Distance from Port to Site	50 km–500 km, 50-km increments

Installation vessel selection is a key driver of installation costs and depends largely on the 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. An anchor-handling tug supply vessel was assumed for installing a project with a semisubmersible substructure. A 10% premium was added to the vessel day rate to account for upgrades that would be required to operate it in deeper waters. A 30% adder was applied to vessel day rates for the 10-MW case to anticipate future vessels and technologies.[34]

Sensitivities were performed using the NREL Offshore BOS Cost Model (Maness and Maples forthcoming) by varying each of the key parameters one at a time for each of the three turbine size 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 Beiter et al. (2016). The resulting curve fits were used to define algorithms implemented in the NREL Offshore Wind Cost Model described by Beiter et al that apply various adjustment factors. Consistent with Beiter et al. (2016), the Jones Act,[35] or any adjustment that could potentially increase installation time or cost for larger turbine sizes were not considered in this analysis (see Beiter et al. 2016 for a detailed discussion).

The 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. These resulting 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 and overall size of the wind power plant. For a full presentation of the equations that were developed from this study and details regarding the development process, see Beiter et al. (2016).

Operation and Maintenance Parameter Study

The OpEx parameter study from Beiter et al. (2016) analyzes the variation of costs with distance between the project and maintenance facilities (e.g., O&M port and/or inshore assembly area)

[34] Vessel day-rate cost adders are qualitative approximations based on information provided by industry.
[35] The Jones Act stipulates that only U.S.-flagged vessels can make deliveries of goods or personnel between points in the United States to which coastwise laws apply (Beiter et al. 2016).

and the prevailing metocean climate at the project site.[36] 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.

For deriving these relationships, the O&M tool from the Energy Research Centre of the Netherlands was applied. The O&M analysis documented in Beiter et al. (2016) assumes that floating turbine components can be towed in a vertical configuration to an O&M or construction port using an anchor-handling tug supply vessel with two assist tugs. Floating wind turbine 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.

Optimized O&M strategies were assumed that simultaneously minimize direct OpEx while maximizing the revenue that the project can generate through power sales (maximizing availability). The assessment approximated 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 the tow-to-shore approach for floating.

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 information, uncertainties about the costs and capabilities of these new vessel types are still present.[37]

The O&M analysis was carried out 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 to 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 could be investigated in the future through additional analysis of the impact of turbine size on maintenance. Further details on each of the scenarios can be found in Beiter et al. (2016).

5.2.3 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 Wind BOS Cost Model (Maness and Maples forthcoming).

[36] O&M costs for floating projects will likely have some sensitivity to water depth because of different vessel and equipment requirements; however, sufficient information is not yet available to accurately quantify this relationship.
[37] Additional factors that were not considered include fluctuation in vessel availability and prices, initial vessel procurement for the U.S. market, or O&M service warranty agreements.

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[38]	15%	Installation CapEx
Fixed Charge Rate (FCR)	The FCR is used to approximate the average annual payment required to cover the carrying charges on an investment and tax obligations	10.51%	All 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 to 6 years. Further details on the cost multipliers are included in Beiter et al. (2016).

5.2.4 Cost Reduction Pathways

NREL's Offshore Wind BOS Cost Model assesses LCOE at different locations and across time-dependent cost-reduction variables. Cost reductions for the two representative offshore wind areas (sites 2 and 5) in California were applied consistently with Beiter et al. (2016). For developing floating technology cost reductions, this analysis followed the methodology framework and inputs of the DELPHOS tool, "a series of cost models and basic data sets to improve the analysis of the impact of innovations on [future offshore wind] costs"[39] 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 from European offshore wind experience. 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.

[38] 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.
[39] KIC InnoEnergy (2016).

The DELPHOS tool applied data obtained from The Crown Estate's 2012 study based on expert elicitations from 54 entities involved in the offshore wind industry and projected The Crown Estate financial close 2020 cost targets out to financial close 2025. 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 model aggregates 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). 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 main purpose of this analysis is to demonstrate that significant cost reductions are possible for both fixed and floating offshore wind turbines and document the methodology for higher-fidelity cost analyses in the future.

As described in Beiter et al. (2016), the DELPHOS cost reduction methodological framework and data were only available for fixed-bottom technology. Technology advancements in the nascent floating sector were not reflected in the DELPHOS tool; therefore, a set of floating innovations was created corresponding to areas where technology advancements were expected (Musial and Ram 2010; James 2015; Catapult 2015) while following the general methodological framework from DELPHOS. Valpy et al. (2014) describes each DELPHOS innovation 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 in Beiter et al. (2016).

6 Analysis Limitations

As described in more detail in Beiter et al. (2016), some general limitations of NREL's Offshore Wind BOS Cost Model that apply to this analysis are as follows.

- To achieve the modeled cost reductions at the two representative Californian locations, site 2 and site 5, a key assumption is that there will be continued investments in technology innovation, developments, and a robust domestic supply chain, commensurate with the established European offshore wind supply chains and sustained domestic offshore wind development (DOE 2015; Navigant 2012; European Commission 2016) during the analysis period from 2015 to 2027 (COD). The cost reductions estimated in this analysis will likely not be realized without sufficient domestic deployment.
- The scenarios defined in this analysis 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 analysis to convert European offshore wind market conditions to U.S. market conditions.
- Domestic cost reductions will require additional activities to reduce risk and uncertainty of early projects, including addressing U.S.-specific challenges (e.g., deeper water) and incentivizing markets (see, e.g., Smith, Stehly, and Musial [2015] and McClellan et al. [2015]).
- The cost model described in Beiter et al. (2016) incorporates a number of simplifications leading to uncertainties that could affect the accuracy of results at any individual location. These uncertainties fall into five primary categories: (1) models—parameter studies were conducted with first-order tools that may not reflect detailed design (e.g., the analysis deliberately does not consider the possible impacts of wake interactions among potential wind projects or detailed soil data), (2) lack of U.S. cost data—no U.S. 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, (4) macroeconomic factors (e.g., exchange rates, commodity prices), and (5) extreme conditions (e.g., variability in extreme wave height data could be a cost driver for offshore wind power projects).
- This analysis does not consider policy-related factors or subsidies, either nationally or in California. 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), the energy sector, or benefits from portfolio diversification (EIA 2015b).[40]

- This study did not take into account all environmental regulations or other environmentally sensitive areas that would need to be considered when deploying an actual wind farm. Developers would need to work closely with regulatory bodies including BOEM, Environmental Protection Agency, Federal Aviation Administration, and California state and local governments to ensure they are considering conservation areas, marine-protected areas, habitats, migration patterns, marine flora, and many other important environmental factors.
- The time frame of this modeling effort considered only the period up to 2027 (COD) (LCOE results extrapolated until 2030). Because floating offshore wind technology is still in a nascent stage of development, the analysis period should be considered a near-term window. It is expected that the viability of floating offshore wind technology will continue to improve beyond the analysis window.
- Fixed-bottom offshore wind project costs are decreasing more rapidly than anticipated by many industry models, including the NREL model described herein. This is evidenced by recent competitive tenders for European projects. For example, the Borssele I&II project in the Netherlands is scheduled to be commissioned in 2020 and represents a 58% reduction (Roland Berger 2016) in power price from 2010 levels. The Krieger's Flak project in Denmark, scheduled for completion by 2022, was awarded in November 2016 with the awarded cost representing a 59% reduction in power price relative to projections made in 2012 (Steel 2016). These price reductions are achieved in part because of a maturing industry that includes a robust supply chain for fixed-bottom offshore wind that is present in Europe today. To what extent these lower costs can be passed on to floating technology in California has not been evaluated.
- There are also some general limitations to the cost-reduction pathway analysis and DELPHOS tool as applied in this analysis. As indicated in Beiter et al. (2016), the cost-reduction pathway analysis presented in this report should be considered preliminary at the present stage. The main purpose of the Beiter et al. (2016) analysis was to demonstrate that significant cost reductions are possible for floating offshore wind turbines using expert elicitation and a system model to aggregate multiple cost and performance contributions. It is 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.

[40] Accelerated depreciation (Modified Accelerated Cost Recovery System) is considered.

Harris 2012). The Beiter et al. (2016) 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 the Beiter et al. (2016) analysis, additional innovations and cost-reduction opportunities were included in the DELPHOS analysis that did not undergo the same level of review as the original 40 cost-reduction areas from The Crown Estate. These additional cost-reduction areas are compelling for the possibility of significant floating offshore wind cost reductions, but because of lack of industry experience and the preliminary status of this analysis, there is a higher degree of uncertainty in the floating criteria presented. The quantification of the uncertainty falls outside of the scope for this study.

7 Cost Analysis Results

Determining the costs to produce electricity at any given location and deliver it to the point of interconnection, excluding any subsidies, was the principal objective of this study. Cost reductions, based on LCOE, were modeled for 2015 (COD), 2022 (COD), and 2027 (COD) and extrapolated to 2030 (COD).[41] The cost analysis focused on the two representative sites that are summarized in Table 7.

Table 7. Summary of Representative Sites

Offshore Wind Reference Area	2 - Channel Islands North	5 – Humboldt Bay Area
Mean Wind Speed (m/s) at 100-m hub height	8.86	9.73
Min, Mean, Max Significant Wave Height (m)	1.8/2.3/2.5	2.7/2.7/2.8
Min, Mean, Max Depth (m)	198/575/774	592/870/994
Construction Port	Port Hueneme, CA	Fields Landing, CA
O&M Port	Port Hueneme, CA	Fields Landing, CA
Centroid Distance to Centroid Distance to O&M Port (Straight Line – km)	127	78
Centroid Distance to Centroid Distance to O&M Port (Avoids Land–km)	127	87
Interconnection Point	Goleta, CA	Eureka, CA
Centroid Distance to Interconnection (Offshore Until Landfall) (Straight Line–km)	69	80
Centroid Distance to Interconnection (Offshore Until Landfall) (Avoids Land–km)	69	87
Distance Point of Cable Landfall to Interconnect (km)	6	5
Area (km^2) <1,000-m depth	445	431
Total Potential Capacity (MW)	1,335	1,293

The resulting LCOE for sites 2 and 5 are shown in Figure 24. The two selected sites have very similar LCOE values as a result of similar spatial conditions (see Section 3). These similarities include comparative wind speeds. This analysis estimates that the LCOE for both sites has the potential to decrease from approximately $185/MWh in 2015 (COD) to approximately $100/MWh by 2030 (COD).

[41] An exponential curve fit using the modeled data from all six sites considered in Section 2 was generated to extrapolate the LCOE data for sites 2 and 5 to 2030 (COD).

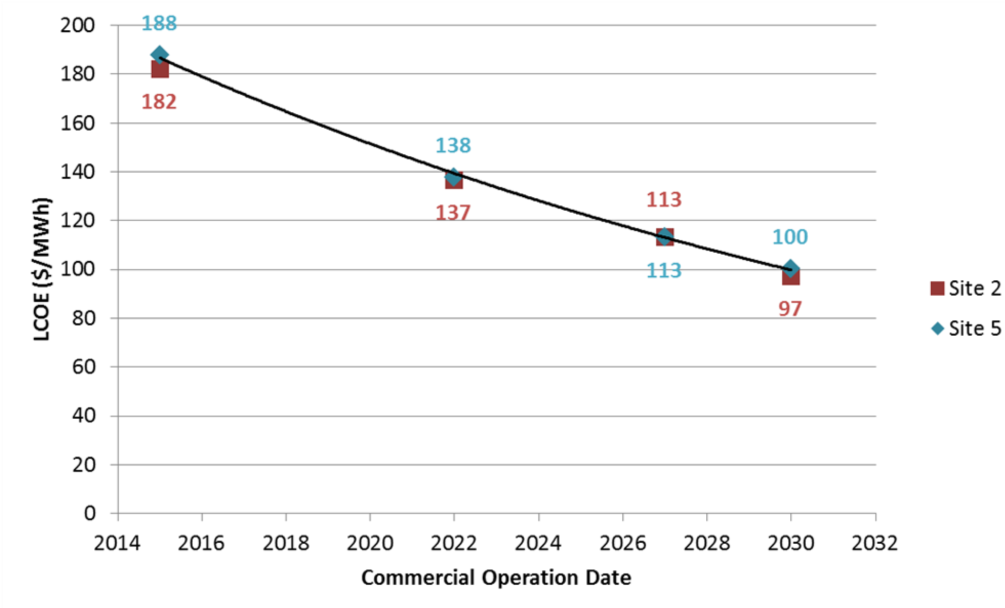

Figure 24. Estimated (unsubsidized[42]) LCOE for California sites 2 (Channel Islands North) and 5 (Humboldt Bay)

Table 8. Estimated LCOE for the Two Representative Californian Sites (Unsubsidized)

Year (COD)	LCOE (in $/MWh)	
	Site 2 (Channel Islands North)	Site 5 (Humboldt Bay)
2015	182	188
2022	137	138
2027	113	113
2030	97	100

Appendix A shows the cost results for all six reference sites that were considered as part of the site-selection process. As discussed in Section 4, sites 2 (Channel Islands North) and 5 (Humboldt Bay) were chosen as they were determined to be representative sites for southern and northern Californian spatial conditions, respectively. These average spatial conditions are reflected in the resulting LCOE (Figure A-1).

Figure 25, Figure 26, and Figure 27 depict the results for different LCOE cost components of the two representative sites, CapEx, OpEx, and net capacity factor.

[42] 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 System) is considered.

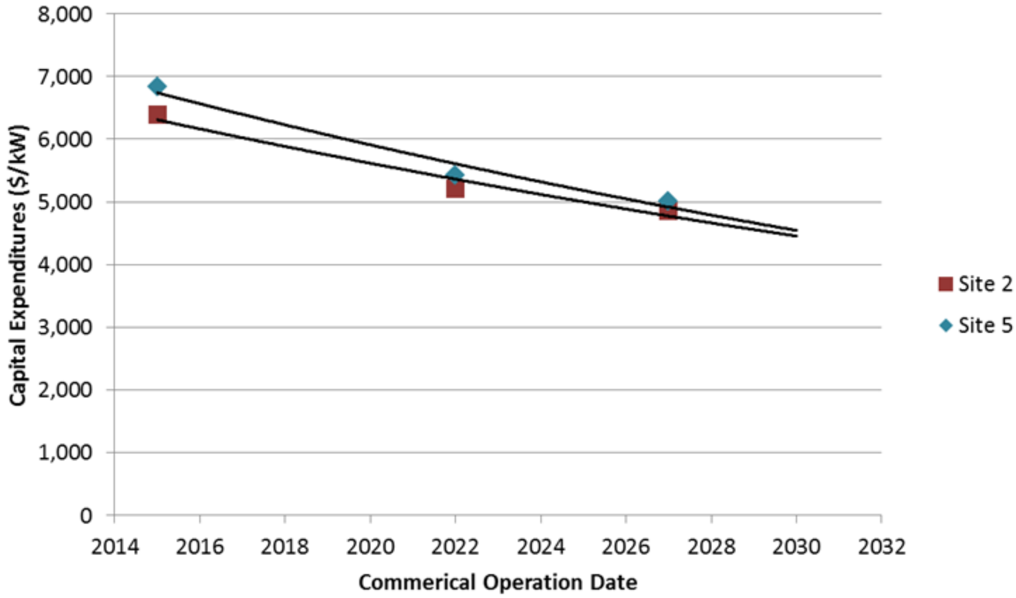

Figure 25. Estimated CapEx for California sites 2 (Channel Islands North) and 5 (Humboldt Bay) (unsubsidized)

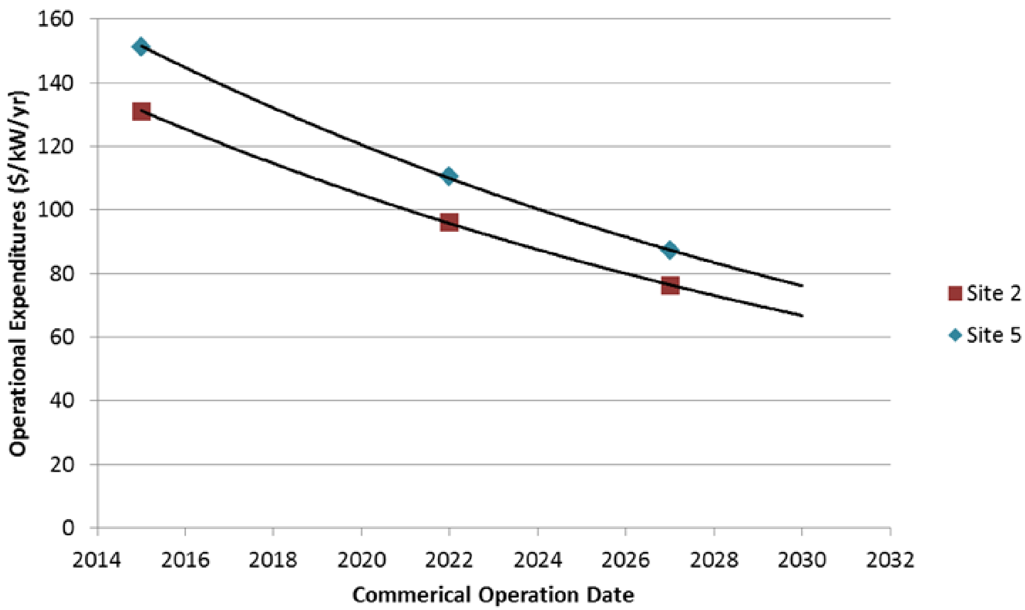

Figure 26. Estimated OpEx for California sites 2 (Channel Islands North) and 5 (Humboldt Bay) (unsubsidized)

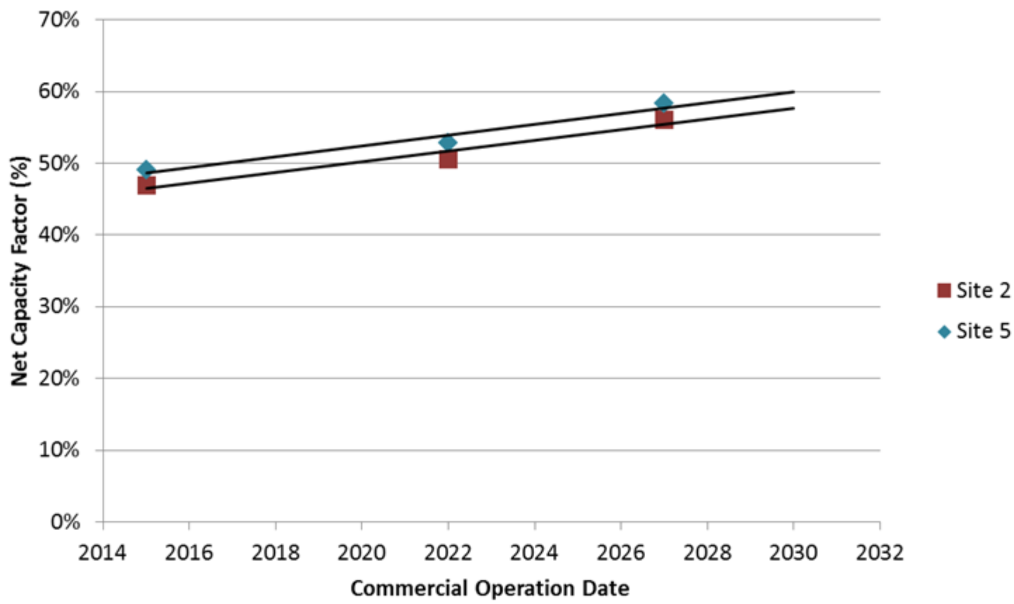

Figure 27. Estimated net capacity factor for California sites 2 (Channel Islands North) and 5 (Humboldt Bay) (unsubsidized)

Further analysis was performed using the database from Beiter et al. (2016). In that analysis, all areas in the California offshore resource area were evaluated for LCOE. In Beiter et al. (2016), 420 sites were assessed within the California technical resource area using the reference 600-MW 10-by-10 wind plant. Figure 28 shows how the six reference sites compare to the entire California resource assessed in Beiter et al. (2016). The results showed that for 2027, the selected sites would likely be among the lowest-cost sites in the state, with exception of the comparatively higher cost site 3. This finding can be attributed to the set of site-selection criteria, which favored sites with the highest wind speeds.

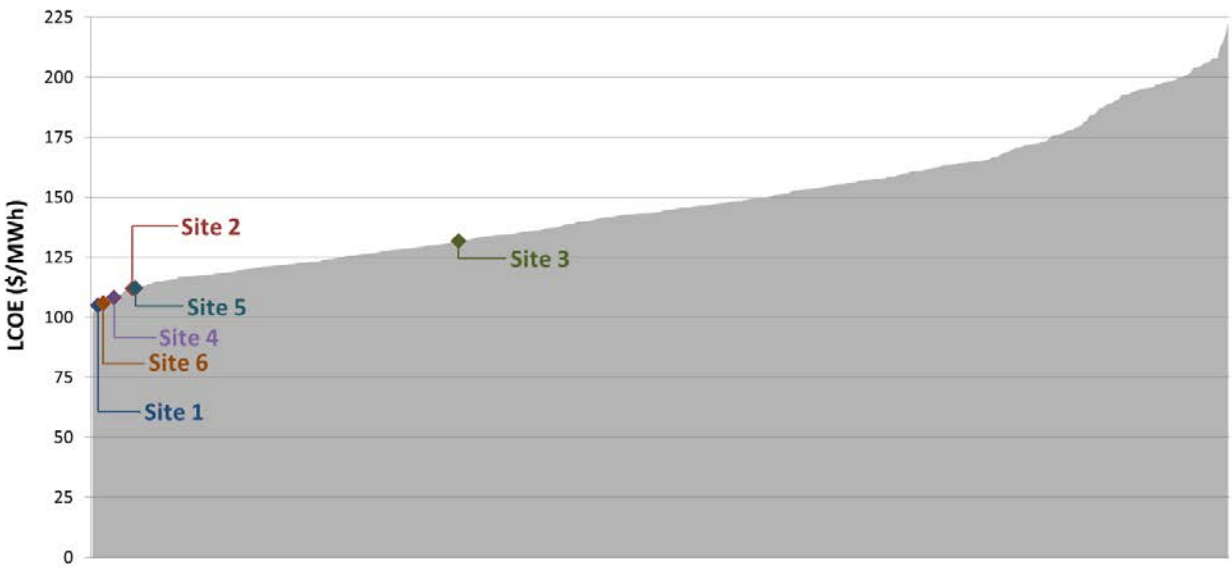

Figure 28. LCOE (unsubsidized) of the entire California technical resource area (420 sites) in 2027 from Beiter et al. (2016) showing selected sites 1–6 assessed in this study

8 Conclusions

This report summarizes unsubsidized cost estimates for offshore wind power in the state of California. The analysis identified six offshore wind areas that were used as reference sites to estimate the cost of floating offshore wind technology, along with an estimate of the energy production potential at those locations. These sites were located in areas where the wind speeds were sufficiently high (ranging from 10.2 m/s to 7.8 m/s) and in water depths that were less than 1,000 m. In addition, they were found to be less conflicted by known human use and major environmental restrictions. The cost study focuses on two of these sites (sites 2 and 5) that were found to be representative of the six sites. The study is not intended to be a precursor for locating BOEM lease areas in California. The conclusions that can be drawn from this analysis indicate:

- There is 112 GW of technical offshore wind resource potential over the entire California coastline (Musial et al. 2016). This corresponds to 392 TWh/year of potential energy production, or about 1.5 times the state's electric energy consumption based on 2014 EIA figures (Musial et al. 2016; EIA 2015a).
- Ninety-six percent of the technical offshore wind resource is in waters deeper than 60 m, indicating that floating wind technology will likely be the most viable option in California and most of the Pacific Coast.
- Market growth curves indicate a growing market for floating wind turbines worldwide and expected commercial phase development by 2025.
- The variation in offshore resource quality and spatial characteristics along the California coast, including distance from shore, water depth, and wave height resulted in relatively small variations in LCOE at the reference sites for 2015, 2022, and 2027 and extrapolating these modeled values to 2030.
- Relatively small differences in LCOE were found between the representative sites 2 and 5, which are indicative of site similarities among the potential California offshore wind sites. Site selection sought sites with the higher wind speeds and lower water depth. But because the water depth increases rapidly, all of the sites were a similar distance from shore (approximately 30 km [see Figure 13]), to avoid nearshore visual impacts and farshore water depth issues.
- The cost-reduction potential from 2015 to 2027 for the two reference sites was also very similar. Site 2 showed a potential reduction from $182/MWh to $97/MWh whereas site 5 showed a potential reduction from $188/MWh to $100/MWh. These similarities are indicative of the cost-reduction assumptions used and the site similarities.
- The baseline cost of the 2015 floating offshore wind technology is derived from only a few deployments that are now several years old, but these California baseline starting points ($187/MWh average across the six considered sites) are the primary element used to establish LCOE in later years. The higher degree of uncertainty in the floating baseline suggests a possible range of future costs when the existing baseline data are updated.

- The economic potential for offshore wind to compete at these costs in California is dependent on the level of policy support, technology attributes, the value of other market factors, and the prevailing electricity prices for the year being considered.
- Grid connections and port services are more abundant and readily accessible in southern California, which may facilitate near-term development in these areas.
- California has a severe wave climate that contributes to higher LCOE because of increased O&M and lower availability. New turbine access methods, tow-to-shore O&M strategies, and a mooring/array cable system designed for easy connect/disconnect will help mitigate these challenges.
- The six reference sites have a combined capacity of over 16 GW of installed capacity and illustrate that offshore wind could be deployed at a scale that is large enough to significantly contribute to California's electricity demand for low-carbon energy. To illustrate the potential contribution of offshore wind, if 1.2 GW (two 600-MW wind plants) were installed at each of the six reference sites, 35.3 TWh/year of offshore wind could be added to the existing generation, which would be approximately 13.5% of California's 2014 electric energy demand.[43]
- Floating wind technology is in a nascent stage and it is unknown at this point which configuration could achieve the lowest costs. However, given recent declines in the cost of energy from fixed-foundations offshore wind projects and the level of innovative floating foundation design work that is now underway, we would expect cost estimates for these technologies to change over time.

[43] This scenario would use less than half of the area of the six sites (see Figure 6) combined.

9 Next Steps

Some areas where the underlying assumptions and relationships in the model could be improved on with additional research are discussed in detail in Beiter et al. (2016). Most importantly, 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. An assessment to quantify the difference between European and U.S. offshore wind market conditions could improve the accuracy of the cost estimates. In addition, a range of sensitivity studies should be conducted to verify the robustness of the model. Because many of the assumptions and relationships developed for this analysis were derived for a national scale, it contains a number of generalizations and uncertainties that may affect the accuracy of results for the specific California sites. These estimates could be improved by conducting more regional assessments of port infrastructure, transmission and grid integration requirements, and market dynamics (e.g., fluctuation in vessel day rates). Recent project data from Europe also suggests that some of the cost, technology, and project risk assumptions will need to be updated regularly to reflect the latest market conditions in this rapidly evolving industry.

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Appendix A. Results for Additional Sites

Levelized cost of energy (LCOE) results for all six sites considered in the site-selection process in Section 2 are depicted in Figure A-1 and Table A-1.

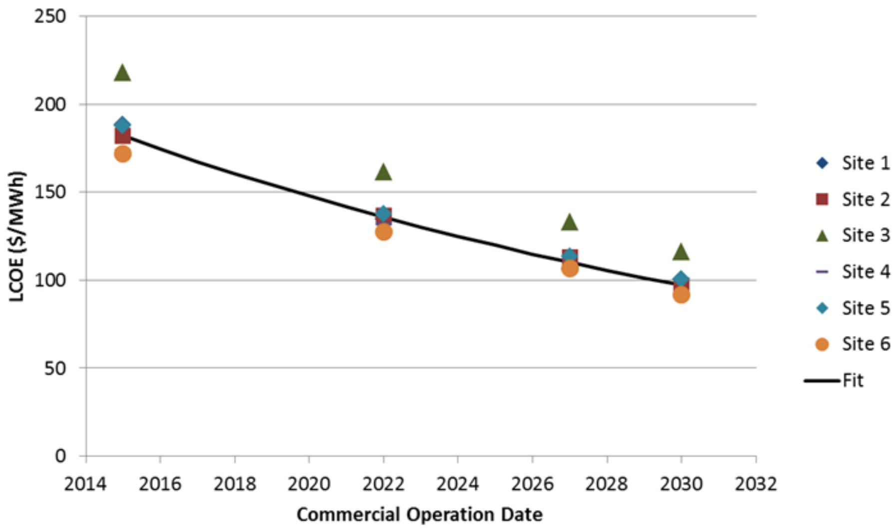

Figure A-1. Estimated LCOE for all six sites considered in the site-selection process (Section 2) (unsubsidized[44])

[44] 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 System) is considered.

Table A-1. Estimated LCOE in U.S. Dollars/Megawatt-Hour for Six Reference Sites (Section 2) (unsubsidized[45])

COD	Site 1	Site 2	Site 3	Site 4	Site 5	Site 6	Fit	% from 2015
2015	187	181	217	172	187	171	182	100%
2016							175	96%
2017							168	92%
2018							161	88%
2019							154	85%
2020							148	81%
2021							142	78%
2022	133	136	160	131	137	126	136	75%
2023							130	72%
2024							125	69%
2025							120	66%
2026							115	63%
2027	105	112	132	108	112	106	110	60%
2028							106	58%
2029							101	56%
2030	100	97	116	92	100	91	97	53%

[45] 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 System) is considered.

Appendix B. Diurnal Power Output for 12 Months

Figure B-1 shows the diurnal power production relationships for all six reference areas over 12 months. The monthly variation can be seen in these charts but the general diurnal patterns remain the same as observed in Figure 17. Peak power tends to occur toward the early evening except in December and January when early morning peaks are seen in the data.

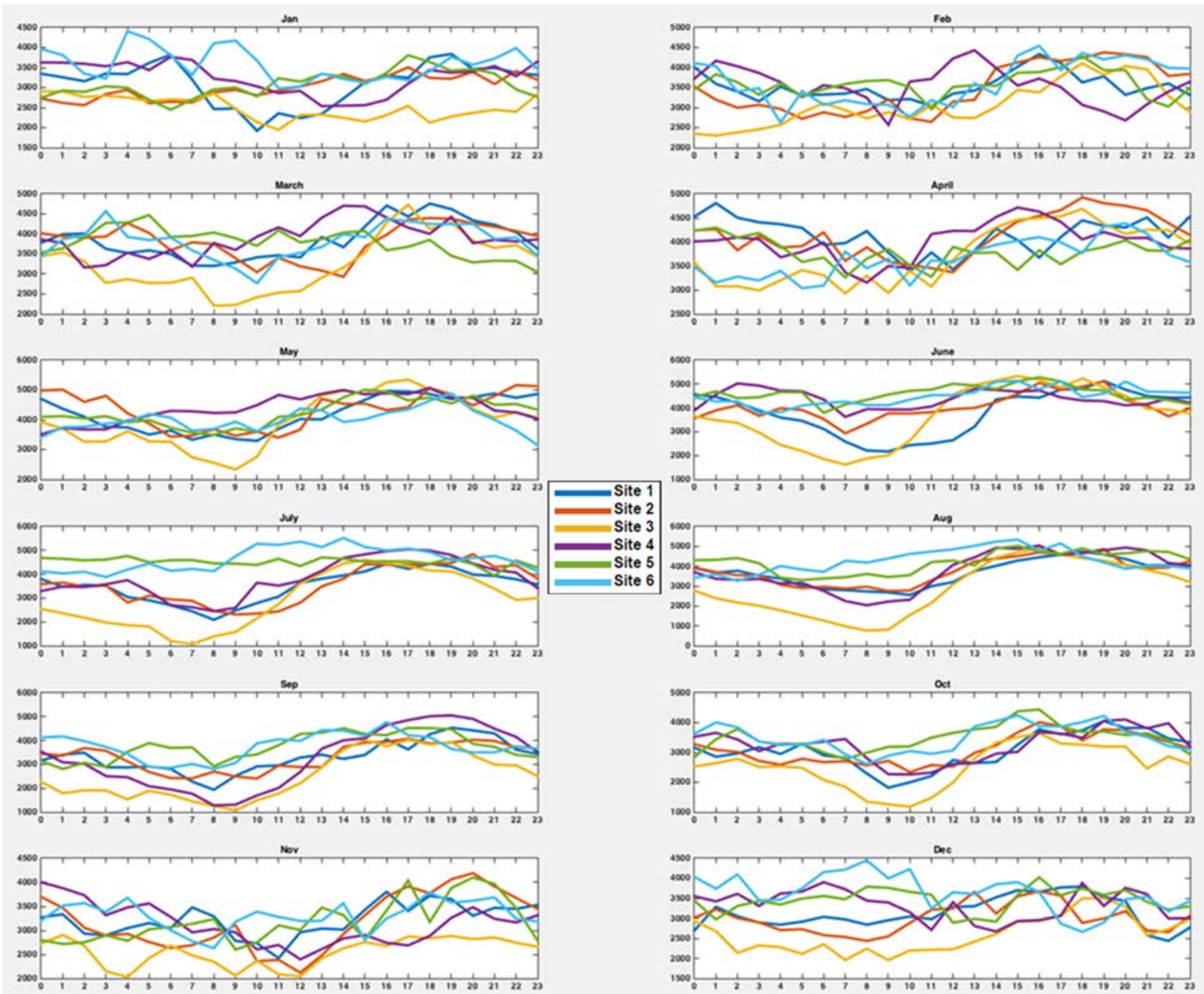

Figure B-1. Diurnal power output for a single 6-MW offshore wind turbine at xix California offshore reference sites

Appendix C. Transmission Maps

Figure C-1 shows locations and types of transmission lines for the state of California as provided by the California Energy Commission. Figure C-2 shows a map of the six offshore wind energy reference areas relative to existing power plants, transmission lines, and interconnection points.

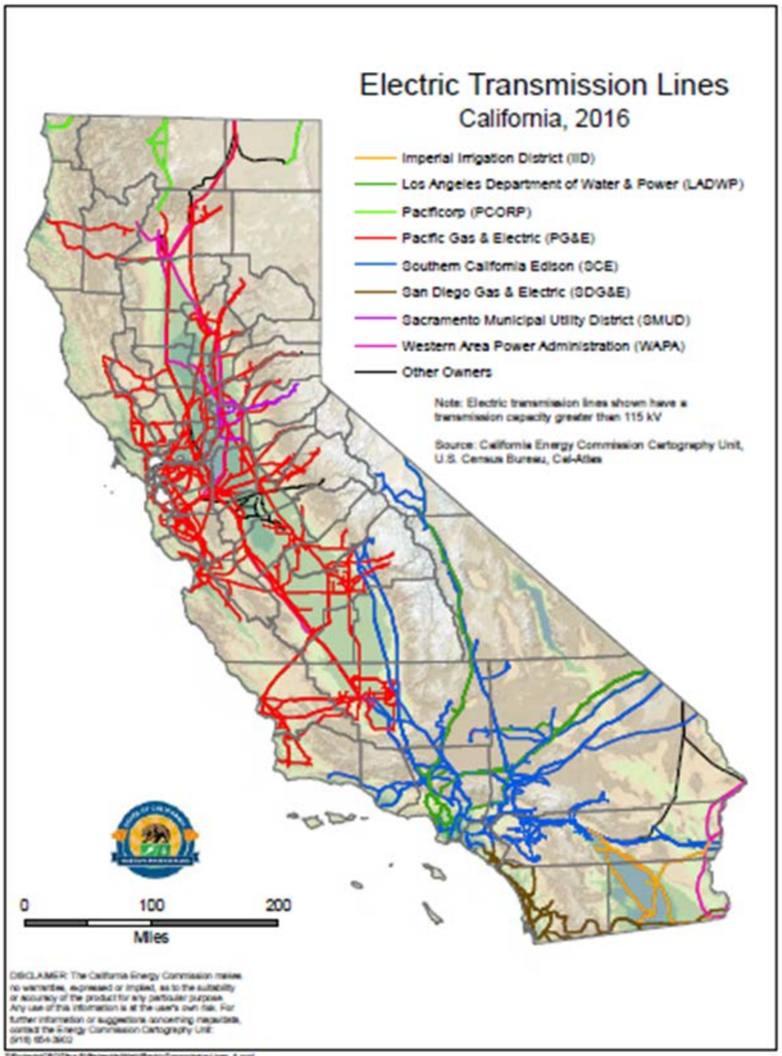

Figure C-1. Transmission lines in California (2016)

(Source: California Energy Commission)

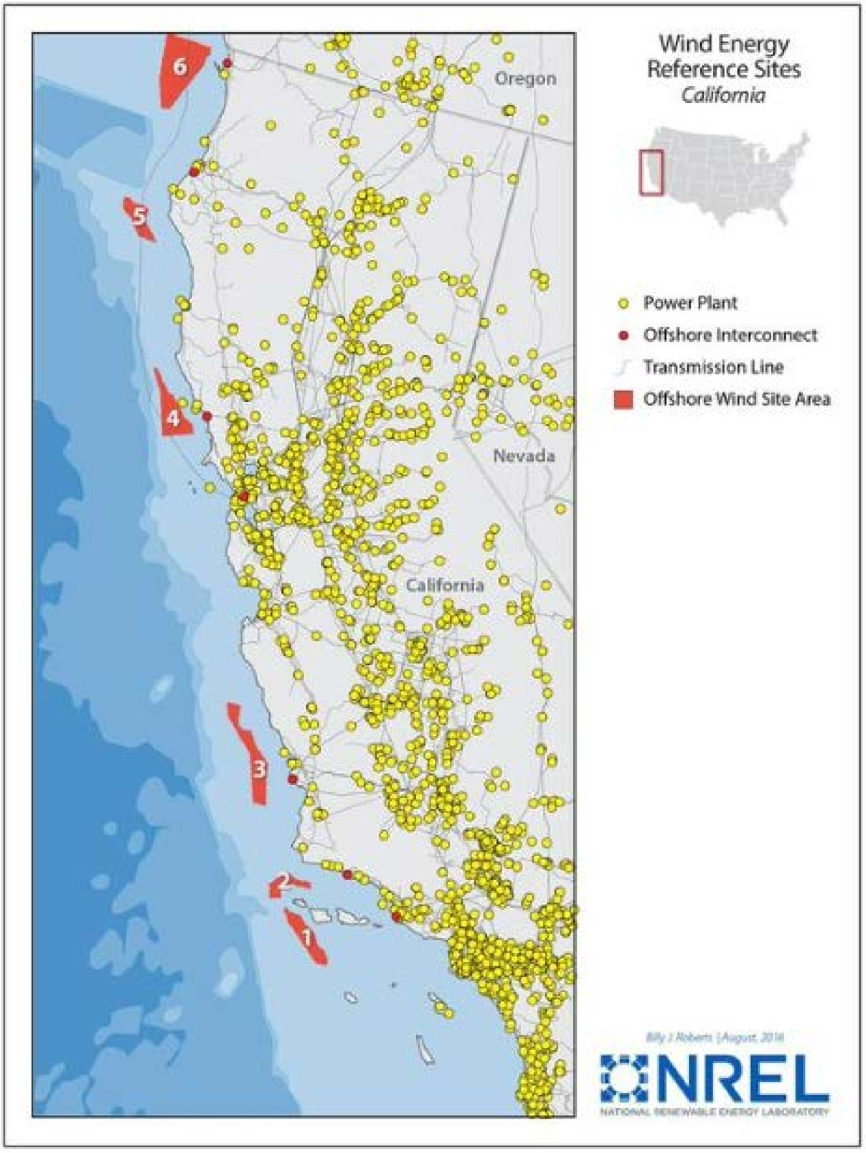

Figure C-2. Potential offshore wind energy areas, power plants, transmission lines, and interconnection points in California

Appendix D. Power Curve Data

Table D-1 provides the tabulated data for the wind turbine power curves shown in Figure 15.

Table D-1. Power Curve Data

Wind Speed (m/s)	NREL 6-MW (2015) Turbine (kW)	NREL 8-MW (2022) Turbine (kW)	NREL 10-MW (2027) Turbine (kW)
1.0	0	0	0
2.0	0	0	0
3.0	0	0	0
4.0	246	359	471
4.5	386	561	733
5.0	562	812	1,059
5.5	776	1,118	1,455
6.0	1,033	1,483	1,928
6.5	1,337	1,911	2,483
7.0	1,691	2,407	3,125
7.5	2,100	2,974	3,860
8.0	2,567	3,616	4,691
8.5	3,096	4,336	5,622
9.0	3,691	5,135	6,655
9.5	4,356	6,015	7,792
10.0	5,092	6,976	8,858
10.5	5,620	7,518	9,417
11.0	5,860	7,813	9,767
12.0	6,000	8,000	10,000
13.0	6,000	8,000	10,000
14.0	6,000	8,000	10,000
15.0	6,000	8,000	10,000
16.0	6,000	8,000	10,000
17.0	6,000	8,000	10,000
18.0	6,000	8,000	10,000
19.0	6,000	8,000	10,000
20.0	6,000	8,000	10,000
21.0	6,000	8,000	10,000
22.0	6,000	8,000	10,000
23.0	6,000	8,000	10,000
24.0	6,000	8,000	10,000
25.0	6,000	8,000	10,000
26.0	0	0	0
27.0	0	0	0
28.0	0	0	0
29.0	0	0	0
30.0	0	0	0