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Financial Viability of Offshore Wind on the Texas Gulf Coast

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Financial Viability of Offshore Wind on the Texas Gulf Coast

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Dedication

I would like to dedicate this work to my loving wife Victoria, who supports me in this and all my endeavors.

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I would like to thank my thesis supervisor Dr. Fred Beach for the encouragement and inspiration and Drs. John C. Butler and David B. Spence for their teaching, guidance, and feedback, which were critical to making this project a reality. I would also like to thank Andy Bowman, Monty Humble, and Dr. David Adelman for their insights.

Abstract

Financial Viability of Offshore Wind on the Texas Gulf Coast

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Offshore wind is already a significant component of the electricity generation mix in Europe, and improvements in technology and cost are enabling increased offshore wind penetration in new markets around the world. Thus far, the US has struggled to materially participate in this industry, with only a single 30 MW offshore project in operation. Navigating a complicated regulatory framework, the lack of a coherent national policy, and facing local opposition, the industry has experienced some spectacular failures in recent years. However, the US now has an opportunity to take advantage of the lessons learned from years of (primarily) European development and combine them with excellent offshore wind resources close to transmission-constrained load centers.

By far the leader of the US onshore wind industry, and with a long history of offshore oil and gas development, Texas has some major advantages when it comes to offshore wind. Wind resources in the Gulf of Mexico are more than adequate for economic production. With shallow depths and relatively calm seas, the Texas Gulf Coast is also well suited to offshore wind construction. These factors, coupled with a pro-development state regulatory scheme and extended jurisdiction over submerged lands, suggest that Texas is an ideal candidate for offshore wind development.

With no currently active projects in the pipeline, this thesis examines the economic viability of offshore wind development on the Texas Gulf Coast at the project level. Using an ideal location and cost data from National Renewable Energy Laboratory (NREL), the Energy Information Administration (EIA), and industry sources, a hypothetical "test project" was developed and evaluated against three cost estimate cases and ten regulatory scenarios. These inputs were fed into a Discounted Cash Flow model to determine potential competitiveness in the Power Purchase Agreement (PPA) market in the ERCOT region.

Results indicate that without significant cost reductions or major changes to either market conditions or federal/state incentive schemes, Texas Gulf Coast offshore wind cannot compete with other forms of onshore renewable generation. With ever-decreasing costs, it is not impossible that offshore wind could become viable at some point in the future, but given current conditions, it is not likely that any projects are on the near-term horizon.

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Chapter 1: Introduction

The Offshore Wind Industry

What is Offshore Wind?

Recorded human use of wind power goes back as far as 7,000 years, beginning with sail powered-boats, and evolving into wind harnessing devices for water pumping and grain processing. The wind industry has waxed and waned over the years, with its fortunes tied to technological advances and the advent (and fluctuating prices of) other power sources. As a low density and variable energy source, wind has significant disadvantages compared to more reliable and energy dense forms of energy like fossil fuels and nuclear fission. These issues make wind economics a game of very narrow margins. It was not until the late 20th century that significant investment was made in its use as a grid-supplying electrical power source.

Offshore wind is simply an extension of onshore utility-scale wind technology to untapped resources off the coast. However, the increased costs of offshore wind are significant impediments to development. Though estimates vary, offshore capital expenditure (CAPEX) and operations and maintenance (O&M) costs can be between two and three times as expensive as onshore installations (Stehly, Beiter and Heimiller 2018, vii, Lazard 2018).

While offshore conditions are far more challenging for personnel and equipment, the wind resource itself is often much stronger and more consistent (DOE 2019b), and in many areas more closely matches demand. If these resources are attractive enough, they can overcome the economic challenges posed by the need for more robust turbines, more highly skilled installers, and more expensive maintenance regimes. Offshore installations also tend to be much closer to load centers than rural onshore projects, which can reduce transmission costs.

Historical Offshore Wind Development

The first-ever offshore wind farm was the Vindeby Project, near Lolland, Denmark (see Figure 1). Built in 1991, the 0.45 MW turbines, 11 in total, were constructed as a test to see if offshore wind development was possible (Lempriere 2017).

Figure 1: Vindeby Offshore Wind Farm

Source: (Lempriere 2017), photo courtesy of Ørsted

The Vindeby farm operated for 26 years until it was decommissioned and dismantled by Ørsted in 2017. While the project itself was quite small, development of the Vindeby farm propelled Denmark to become a world leader in wind energy.

Though the Vindeby farm can be thought of as the beginning of the offshore wind industry, the industry did not reach significant size for many years. What is considered the first large scale offshore wind farm, the 40 MW Middelgrunden wind farm (another Danish project, see Figure2), did not go into service until 2000 (Wind Europe 2019).

Figure 2: Middelgrunden Wind Farm

Source: author's photograph

Much of the early offshore wind development was in Europe due to a confluence of local expertise, an abundance of suitable sites which were more favorable than onshore locations, and supportive public policies.

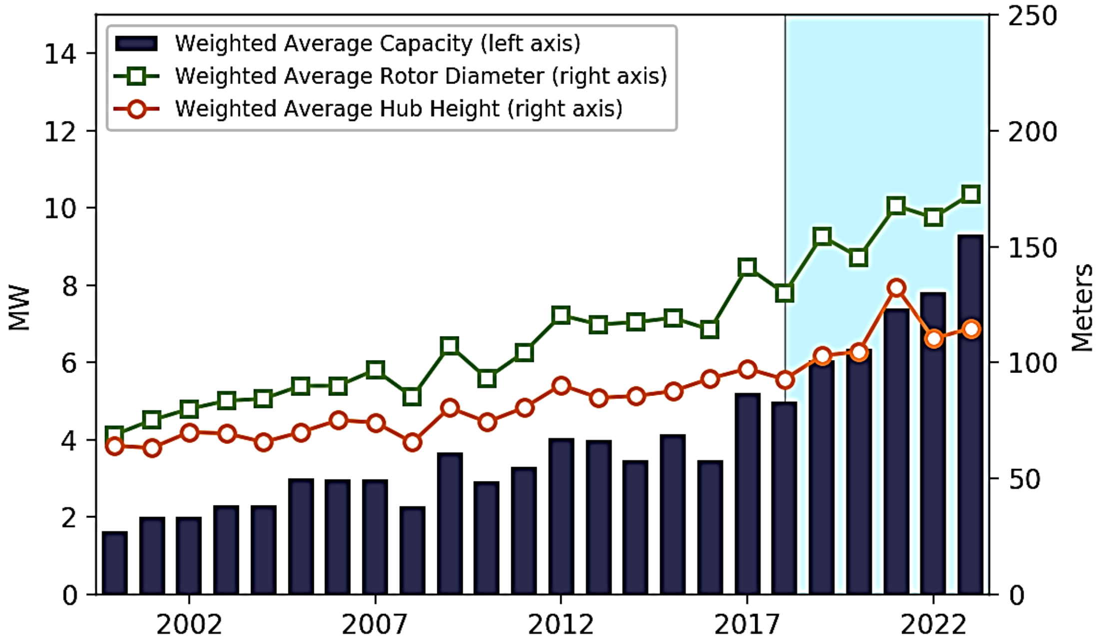
Despite all this development, the cumulative offshore wind capacity in Europe did not break 1 GW until 2007 (Bilgili, Yasar and Simsek 2011, 910). At that time European offshore wind farms accounted for more than 99% of worldwide offshore capacity, with only Japan and China having installed capacities of 11 and 2 MW respectively. Until recently, only China has built out significant non-European offshore capacity (Beiter, Spitsen, et al. 2018).

Chapter 2: State of the Offshore Wind Industry

TECHNOLOGY

Turbine and supporting infrastructure technologies have come a long way since the early days of offshore development. The biggest difference has been the massive increase in the size of offshore turbines. Figure 3 illustrates the rapid pace of increasing nameplate capacities, rotor diameters, and hub heights.

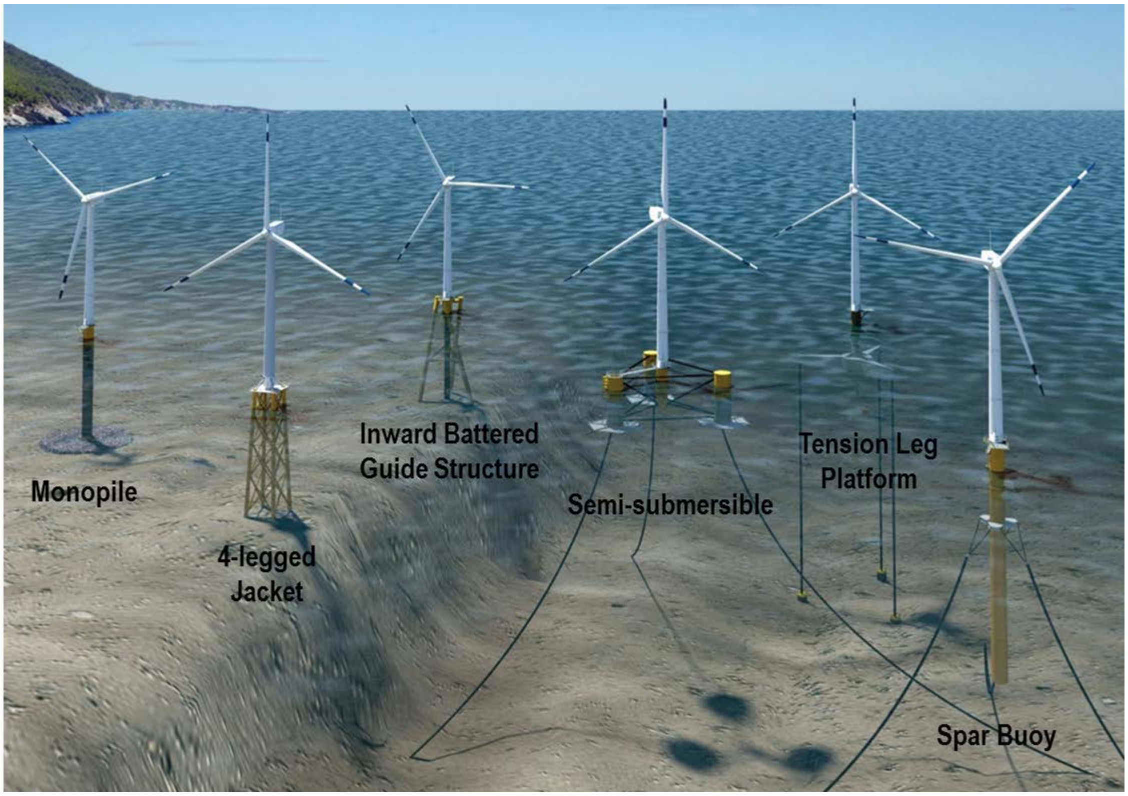
Figure 3: Global Turbines Capacities, Rotor Diameters, and Hub Heights by Installation Year



Source: (Beiter, Spitsen, et al. 2018, 60)

Modern offshore turbines are many times more powerful than their earlier counterparts. Larger turbines are inherently more efficient, and technological advances in substructures have allowed for siting in deeper waters further offshore to access better wind resources (see Figure 4 for a depiction of different substructure types).

Figure 4: Offshore Wind Substructure Types



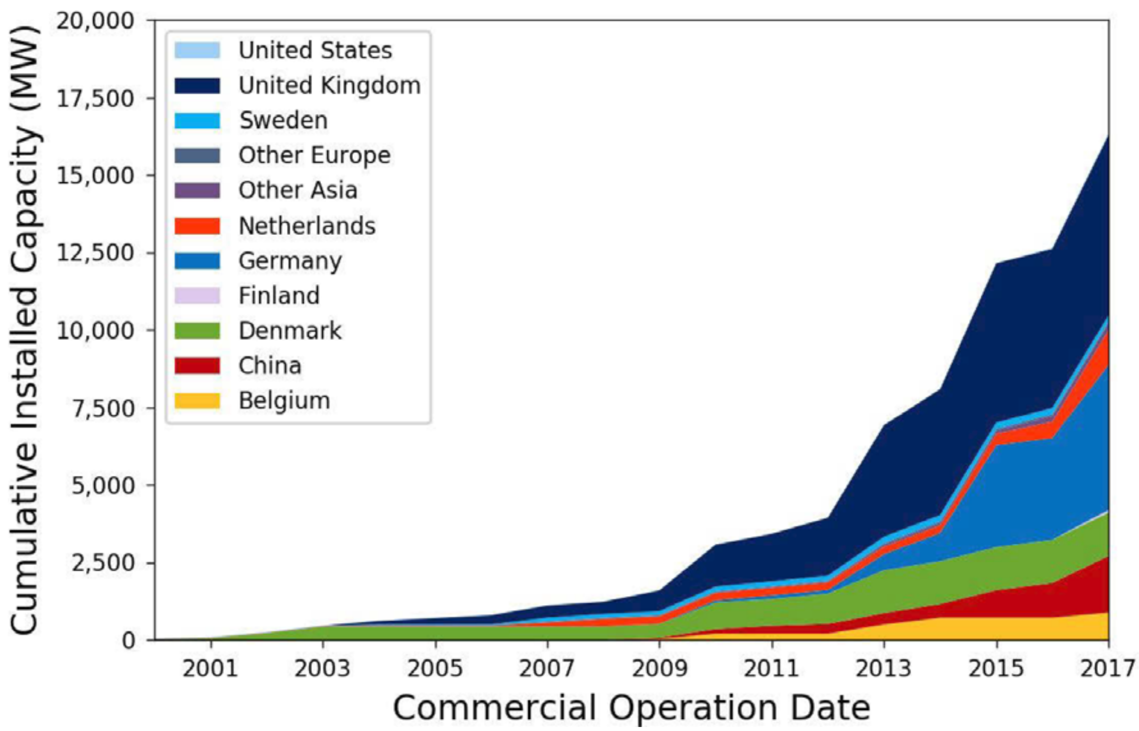
Source: Adapted from (Beiter, Musial, et al. 2016, 8)

Substructure requirements vary by depth of installation. While many early installations used simple concrete gravity bases (not pictured in Figure 4), most offshore wind turbines today are mounted on steel monopiles. These steel monopiles are often the cheapest option, but are suitable only for shallow waters with stiff soil conditions (Beiter, Musial, et al. 2016, 8). Deeper waters and very large turbines often require more complex and expensive substructures, and in depths beyond approximately 60 meters, only floating turbines (still in the experimental and testing stages) are viable.

European and Worldwide Deployment

As of 2017, there was approximately 16.5 GW of total offshore wind capacity worldwide. As shown in Figure 5, the United Kingdom and Germany have become the two leading countries as measured by total capacity, and European turbine manufacturers and developers such as Siemens Gamesa, Vestas, and Ørsted have come to dominate the industry.

Figure 5: Share of Cumulative Offshore Wind Capacity by Country



Source: (Beiter, Spitsen, et al. 2018, 42)

Much of this development has come on the back of significant government subsidies from European countries. The types and mechanisms for these subsidies have varied over the years, and currently, many countries run reverse auctions where developers bid on who will take the lowest subsidy (Graré, et al. 2018).

Non-European development has been led by China with a seven-fold increase in offshore capacity in the last five years. While still lagging behind the UK and Germany China now fields the third largest offshore fleet with 1796 MW installed (Beiter, Spitsen, et al. 2018, 42).

US Development

Block Island, the first US offshore wind farm

The offshore wind industry in the US faces many difficulties and has been slow to develop. Pictured in Figure 6, the first and only currently operating offshore installation is the Block Island Wind Farm off Rhode Island, which did not enter commercial operation until December 2016. The array itself is quite small, with only a 30 MW capacity from five turbines. The site was developed by Deepwater Wind (recently acquired by Ørsted) utilizing GE turbines (Deepwater Wind 2019).

Figure 6: Block Island Wind Farm

Source: Deepwater Wind

The Block Island Wind Farm provides power to nearby Block Island, which had relied on expensive diesel generators, but it is also connected by undersea cable to the mainland. While the project is successfully operating, the long-term Power Purchase Agreement (PPA) price of $0.244/kWh with a 3.5% annual escalator (Trabish 2015) is far above even the relatively high Independent System Operator (ISO) New England system average price of ~$0.044/kWh (ISO New England 2019).

Federal Regulatory Environment

The Submerged Lands Act of 1953 established the jurisdictional boundaries for the development of resources within United States' submerged lands. For all states except Texas and the Gulf Coast of Florida, those state submerged lands extend from the coastline to 3 nmi. The Bureau of Ocean Energy Management (BOEM) is designated as the lead agency, and, in conjunction with other federal and state agencies, is charged with the management of these resources. The federal leasing process automatically triggers the need for a major federal permitting and review process.

Table 1: Federal Regulatory Requirements and Agencies

Regulatory Requirement	Controlling Statute	Agency
Leasing and royalty requirements	Outer Continental Shelf Lands Act of 1953 (as amended by the Energy Policy Act of 2005)	BOEM
Environmental impact review	National Environmental Policy Act (NEPA) of 1969	EPA
Endangered species biological assessments/incidental take permits	Endangered Species Act of 1973	NMFS/FWS
Migratory birds	Migratory Bird Treaty Act of 1918	FWS
Water quality	Clean Water Act of 1977	EPA
Maritime traffic, navigation, and safety	Ports and Waterways Safety Act of 1972; Rivers and Harbors Act of 1899; 33 CFR §66.01	USCG/Army Corps of Engineers
Impacts on historic properties/sites	National Historic Preservation Act of 1966	BOEM in consultation with Advisory Council on Historic Preservation; NPS
Crew safety requirements	Occupational Health and Safety Act of 1970	DOL/OSHA
Aviation safety	Federal Aviation Act of 1958; 49 U.S.C. §44718	FAA

Source: (Cameron Jr. and Mathews 2016) (Eisen, et al. 2015, 836-838)

Table 1 offers a synopsis of the major federal regulations that commonly apply to offshore wind development. It is by no means exhaustive but serves to illustrate the volume of regulatory and permitting issues facing an offshore project. One other requirement to note is Jones Act compliance. Under the Jones Act, shippers moving goods between US ports must utilize US built, flagged, and crewed vessels. Currently, there are no US flagged turbine installation vessels nor US-based offshore turbine manufacturing facilities. Given the requirement, developers may be required to ship turbines from Europe directly to the installation vessel on site (Smith, et al. 2018, §9.05).

Despite recent efforts by the Department of the Interior (DOI) to streamline the federal approval process for offshore wind developments with its "Smart from the Start" program (Eisen, et al. 2015, 836), the regulatory and permitting process remains a significant impediment. Even for projects that are fully compliant, the legal fees, environmental study costs, administrative overhead, and delays can accumulate to the point that they adversely affect project returns and may even kill an otherwise viable project.

State and Local Regulation

While states do not have leasing or final environmental permitting authority for projects in federal waters, they do have significant ability to influence offshore wind installations. Avoiding state and local opposition has become an important factor in initial site selection.

Though a project may be sited in federal water, some portions of the development process, especially during installation, are directly in state and local jurisdiction. Probably the most significant regulatory hurdle is approval under the state Coastal Zone Management Plan (CZMP). Pursuant to the Coastal Zone Management Act of 1972, states create their own CZMPs to regulate their state's coastal areas and submerged lands in partnership with the federal government (Cameron Jr. and Mathews 2016). States can be a major obstacle if they are unsupportive of a project because they are given broad leeway to define requirements for transmission and permits for the use of coastal facilities. Developers must also obtain state Clean Water Act (CWA), Right-of-Way (ROW), and Department of Transportation (DOT) permits (Eisen, et al. 2015, 837-838).

Even in states with broad support for clean energy, offshore development is not always welcome. As a recent example, Ocean City, Maryland passed an ordinance in 2018 opposing offshore developments that can be seen from shore (Smith, et al. 2018, §9.05). Despite federal siting and approvals, state and local opposition is a common and significant issue for offshore wind.

Failures, Issues, and Controversy

Beyond cost, offshore wind developments face many more hurdles than onshore projects. The Cape Wind project was a spectacular example of difficulties developers face in the US. Originally conceived in 2001 to be the first US offshore development and located in Nantucket Sound, the project's developers faced years of setbacks, delays, and opposition until finally abandoning the project in 2017 (Walton 2017).

Cape Wind, like other offshore projects, found itself facing significant local opposition. While this is not completely uncommon for onshore projects, given the population density and affluent nature of many coastal communities, NIMBYism (Not In My Back Yard) is magnified. Located in federal portions of Nantucket Sound, the Cape Wind project was challenged by committed and well-funded groups on nearly all conceivable grounds. While this project's tortured history may be an extreme example, it brought to the forefront many issues offshore developers must now take into account when considering a new project.

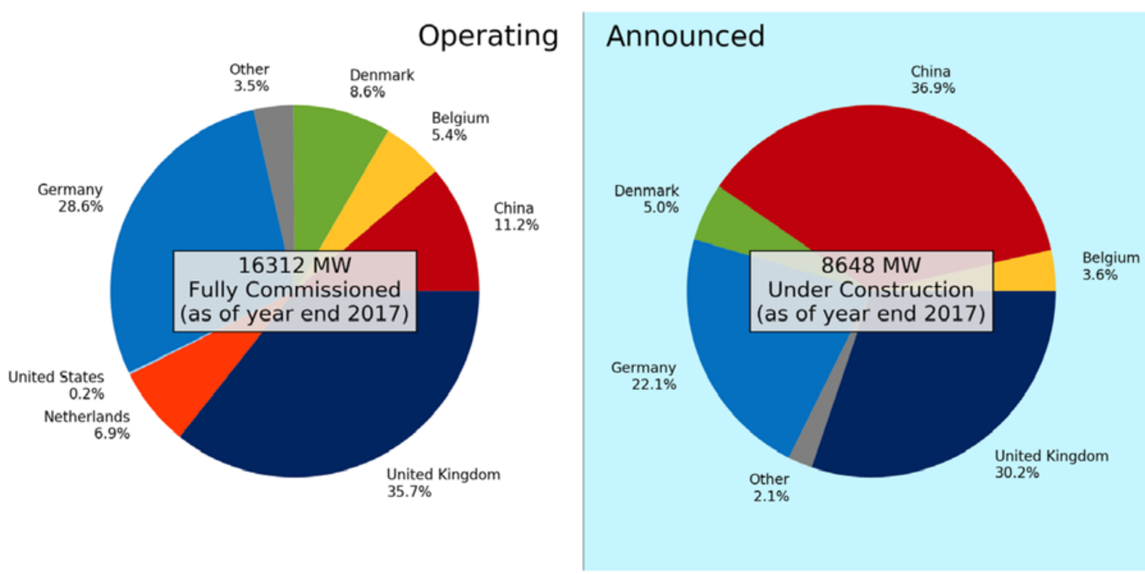
FUTURE OF OFFSHORE WIND

Without the onshore logistical limitations imposed by highway and train transport, the average size of offshore wind turbines will only continue to grow. Increases in efficiency and cost reductions will also make offshore wind more cost competitive with other resources. As floating turbine designs become proven and operationally available, vast resource areas may open up for development. Furthermore, concerns about greenhouse gas emissions as well as geopolitical risks surrounding energy security will drive more countries to consider offshore development as an integral part of their generation mix.

Globally

Worldwide deployment of offshore wind will continue to accelerate over the next several years, but, as shown in Figure 7, much more development will occur in Asia and specifically China.

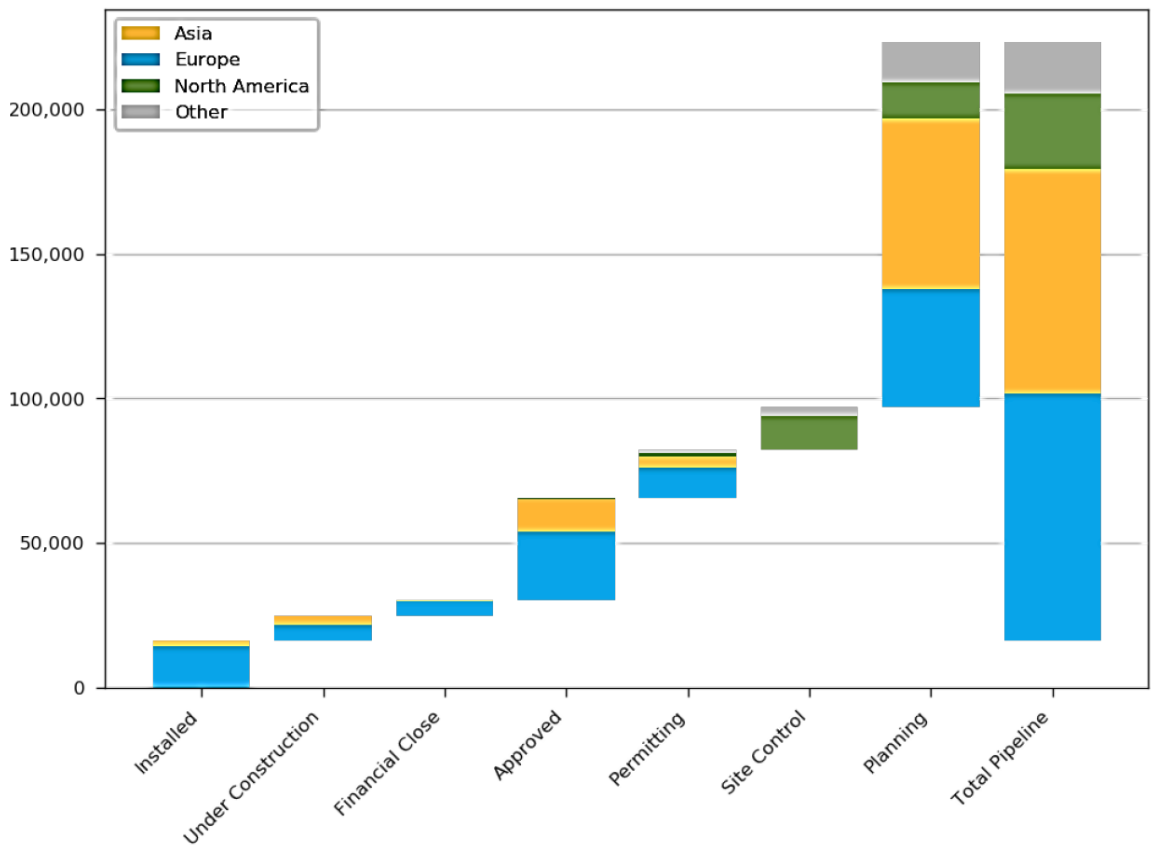
Figure 7: Comparison of Current Share by Country vs. Under Construction



Source: (Beiter, Spitsen, et al. 2018, 43)

Already a leader, China will more than triple its current offshore capacity with projects already under construction. Taiwan has entered the market, with a plan to construct 5.5 GW of offshore wind by 2025 (Beiter, Spitsen, et al. 2018, 40). As shown in Figure 8, the total global pipeline of announced projects, which includes the projects under construction from Figure 7 as well as projects at earlier stages in the development pipeline, exceeds 200 GW, representing a 12-fold increase.

Figure 8: Global Offshore Wind Pipeline (MW)

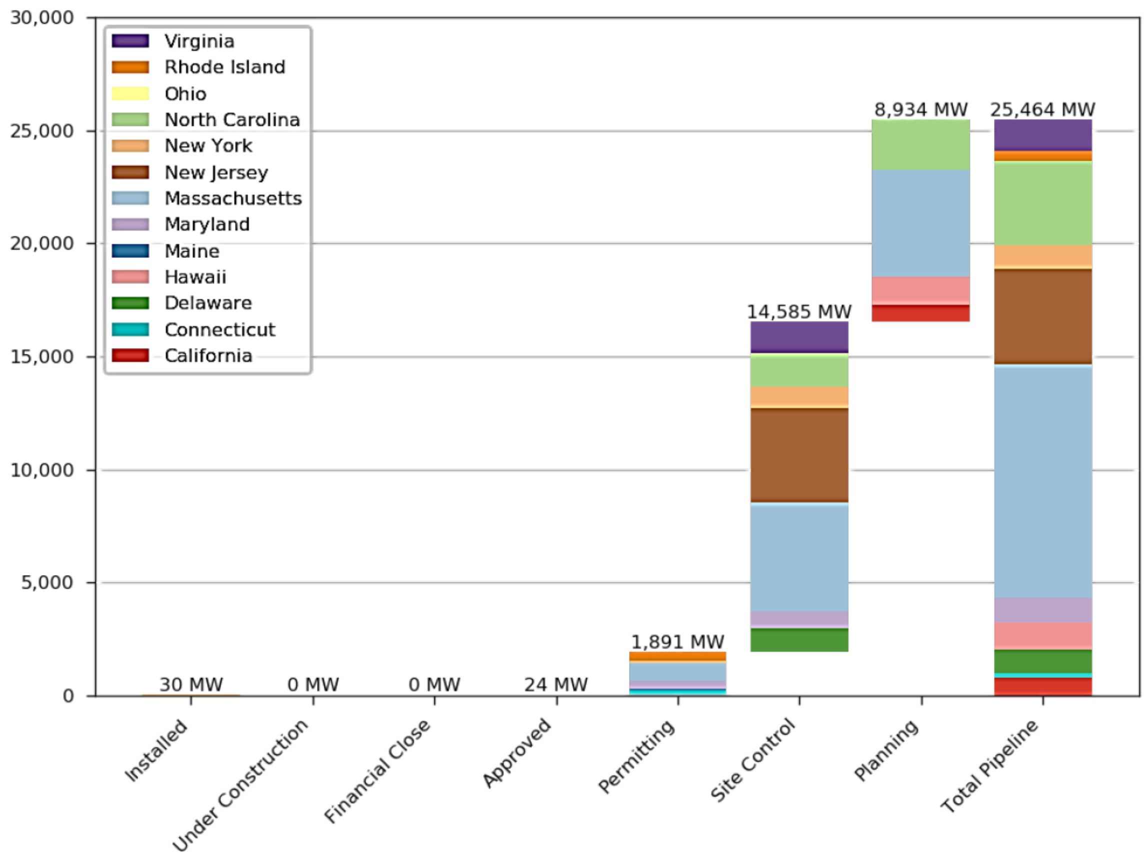


Source: (Beiter, Spitsen, et al. 2018, 45)

United States

Despite the setbacks and challenges, the offshore industry is poised to take off in the US. Taking advantage of cost reductions and lessons learned built on years of (mostly) European development, many new US projects are in the pipeline.

Figure 9: US Offshore Wind Pipeline (June 2018)



Source: (Beiter, Spitsen, et al. 2018, 22)

While there are over 25 GW in the total pipeline, new US projects are, overall, still very much in the early stages of development. Announced projects are predominantly located in the New England/Mid-Atlantic region. The combination of excellent wind resources, environmental impact interests, and high wholesale power prices in transmission and land-constrained markets have made this area attractive to developers. Without an overarching federal scheme and with federal tax credits quickly expiring, states have modified existing or developed new procurement mechanisms to encourage offshore growth (see Table 2). States like Massachusetts, New York, New Jersey, and Connecticut have completed or announced requests for proposals (RFPs) for offshore wind, and some are implementing specialized Renewable Energy Credit (REC) programs specifically targeting offshore wind. Early stage projects are also in development to centralize transmission via an offshore transmission network.

Table 2: State Offshore Wind Procurement Targets

State	Offshore Wind Procurement Target	Year
Massachusetts	1,600 MW	2027
Connecticut	825,000 MWh/yr	
New York	2,400 MW	2030
New Jersey	3,500 MW	2030
Maryland	2.5% of retail sales	

Source: (Beiter, Spitsen, et al. 2018, 33)

Due to increased depths and the requirement for floating turbines, development progress in the Pacific is much slower. California and Hawaii both have projects in the planning stages, which stand to take advantage of high prices in both regions if the technology can be proven at acceptable cost levels.

Chapter 3: Offshore Wind Development in Texas

In an effort to avoid federal jurisdiction and regulation, Texas has developed it's own, non-interconnected, transmission grid. Managed by the Electric Reliability Council of Texas (ERCOT), operating as an ISO, the ERCOT region covers about 90% of the Texas load (ERCOT 2019).

RESOURCES

The state of Texas is rich in natural resources. Already a major energy producer with large oil and gas deposits, Texas quickly became a leader in onshore wind energy production in the mid-'90s, and has rapidly expanded installed wind capacity as shown in Figure 10.

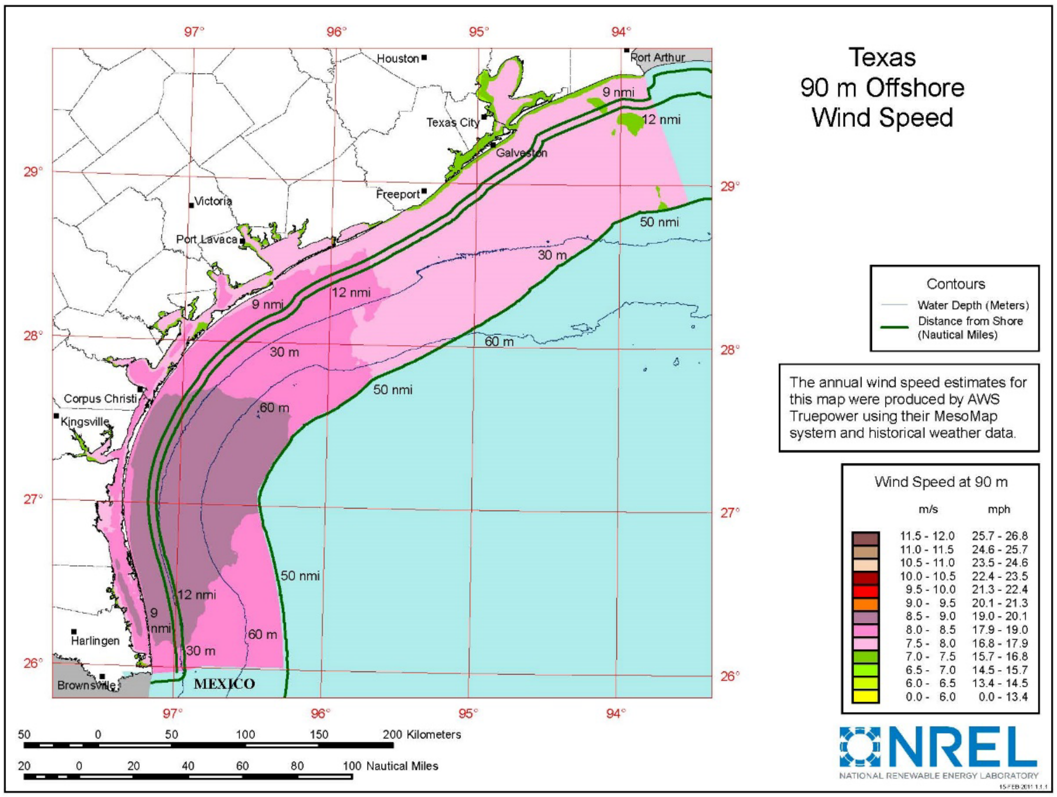
Figure 10: Wind Capacity in ERCOT

Source: (ERCOT 2019)

In 2018, 69,796,019 MWh of wind energy was consumed in ERCOT; or 18.6% of the total load (ERCOT 2019). Most of this wind generation is in West Texas and the panhandle, with some onshore coastal wind as well.

Texas also has significant offshore wind resource potential, as illustrated in the wind speed map in Figure 11.

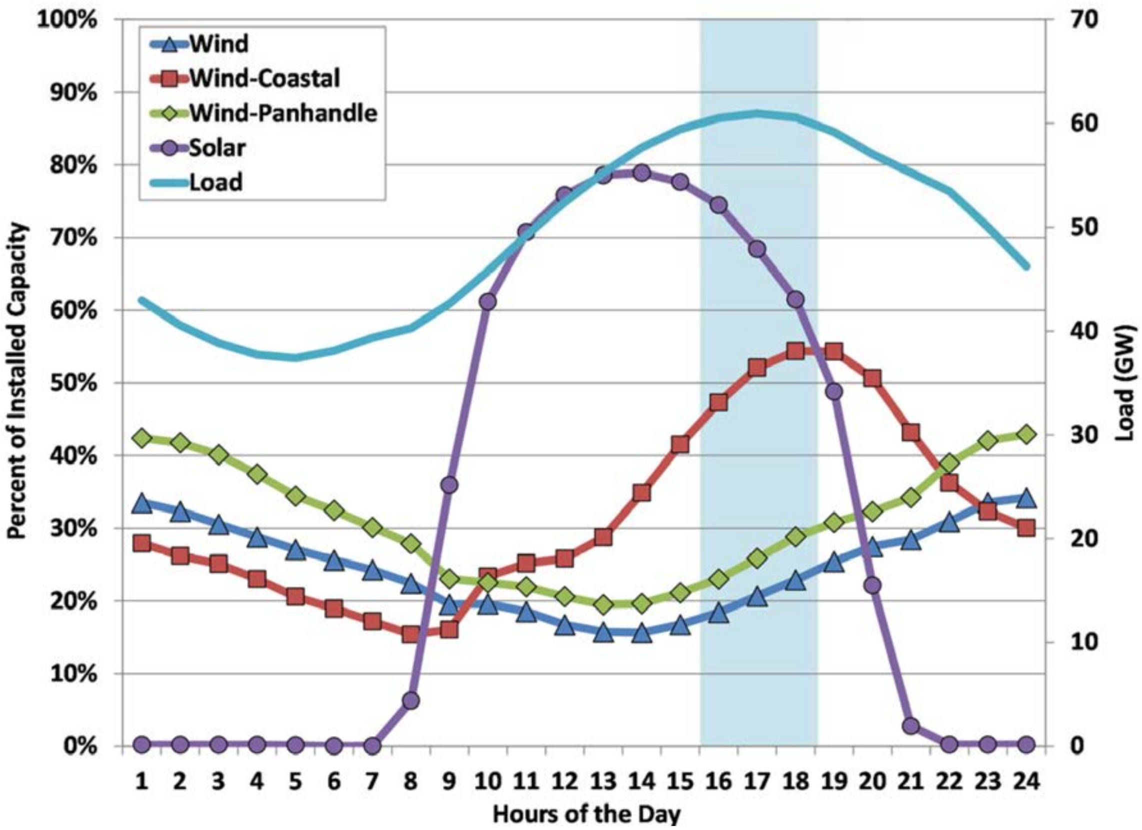
Figure 11: Texas 90 m Offshore Wind Speed



Source: (NREL 2011)

Close to major coastal cities and avoiding much of the transmission congestion new west Texas and panhandle wind development faces, Texas offshore wind is very attractive from a resource perspective. An additional benefit which is already making onshore coastal wind production more valuable is its generation profile.

Figure 12: ERCOT Summer Renewable Production



Source: (Potomac Economics 2018, 88)

As shown in figure 12, the coastal wind generation profile (shown in red) very closely follows the total load curve. The additional buildout of coastal and offshore wind has the potential to meet much of the generation need in ERCOT with less reliance on dispatchable resources to match generation to load. Additional coastal and offshore wind would also reduce the steep ramping need caused by increased solar penetration which drops off shortly before peak demand times.

REGULATORY AND MARKET ENVIRONMENT

As stated earlier, ERCOT has significant autonomy with regards to its management of the grid. It has also invested heavily in the infrastructure needed to accurately forecast wind generation, making it possible for ever higher levels of intermittent resources on the Texas grid (ERCOT 2019). Both the state legislature and the Public Utility Commission (PUC) of Texas have, through the restructuring of the electricity market to introduce competition, also been supportive of new generation development.

One of the only areas in the country with growing electricity demand, the market for wholesale electricity in Texas is vibrant. The system is built around a day-ahead and real-time market administered by ERCOT, supplemented by long-term PPAs that allow Load Serving Entities (LSEs) to hedge price risk and provide the necessary revenue predictability needed to finance generation projects.

The state has developed a unique arrangement where, after a generator reaches commercial operation, the security deposit that the developers pay to the Transmission Service Provider (TSP) for the required upgrades to transmission facilities for interconnection are returned (Smith, et al. 2018, §7.02). The TSP (as a fully regulated entity) recovers the cost through its rates for all customers. This socialization of transmission costs makes generation interconnection in Texas more affordable than in other states where generators pay for much of the of upgrade costs.

Though the regulatory burden in Texas is significantly reduced, developers must contend with requirements beyond ERCOT's interconnection rules, some of which are described below:

General Land Office (GLO)

For projects sited on state lands, the GLO manages the permitting and leasing process, functioning in a similar manner to the Department of the Interior. The GLO also manages state submerged lands off the Gulf Coast out to the state submerged land boundaries. As a remnant of Texas' unique history and under the Outer Continental Shelf Lands act of 1953 and subsequent Supreme Court ruling (Smith, et al. 2018, §9.01), Texas' submerged lands extend out to 9 nmi (vs. 3 nmi for all other states except the Florida Gulf Coast) to what is known as the Three Marine League Line (TMLL). This stipulation has provided a windfall of resources and revenues for the state and potentially provides a significant advantage to developers if they are able to avoid the federal leasing process by locating solely on state-administered submerged lands. Lease agreements work in two phases: an initial development term paid per acre followed by a second term of construction and operation which is paid as a percentage of revenues (Smith, et al. 2018, §9.02). Developers must also gain right-of-way easements for transmission lines and accommodate existing oil and gas leases and easements.

Texas Counties

Texas county and school district taxing jurisdictions extend seaward to into the Gulf to the TMLL. Without a state income tax, property taxes properties are a significant source of revenue, but Texas counties and school districts have wide latitude in creating abatement agreements to attract local development.

Federal Requirements

Projects on Texas submerged lands do not avoid all federal regulation. Approvals under the Clean Water Act and from the Army Corps of Engineers are still required, and a full environmental review under NEPA may still be necessary (Smith, et al. 2018, §9.01).

CURRENT TEXAS OFFSHORE DEVELOPMENT

While the GLO has issued leases, no offshore wind farms have been built on the Texas Gulf Coast. Baryonyx secured leases in 2009 and received a DOE grant to help fund project, but allowed its lease to expire in 2014 (Smith, et al. 2018, §9.02). Other leases have been issued, but no projects have made it past the development stage.

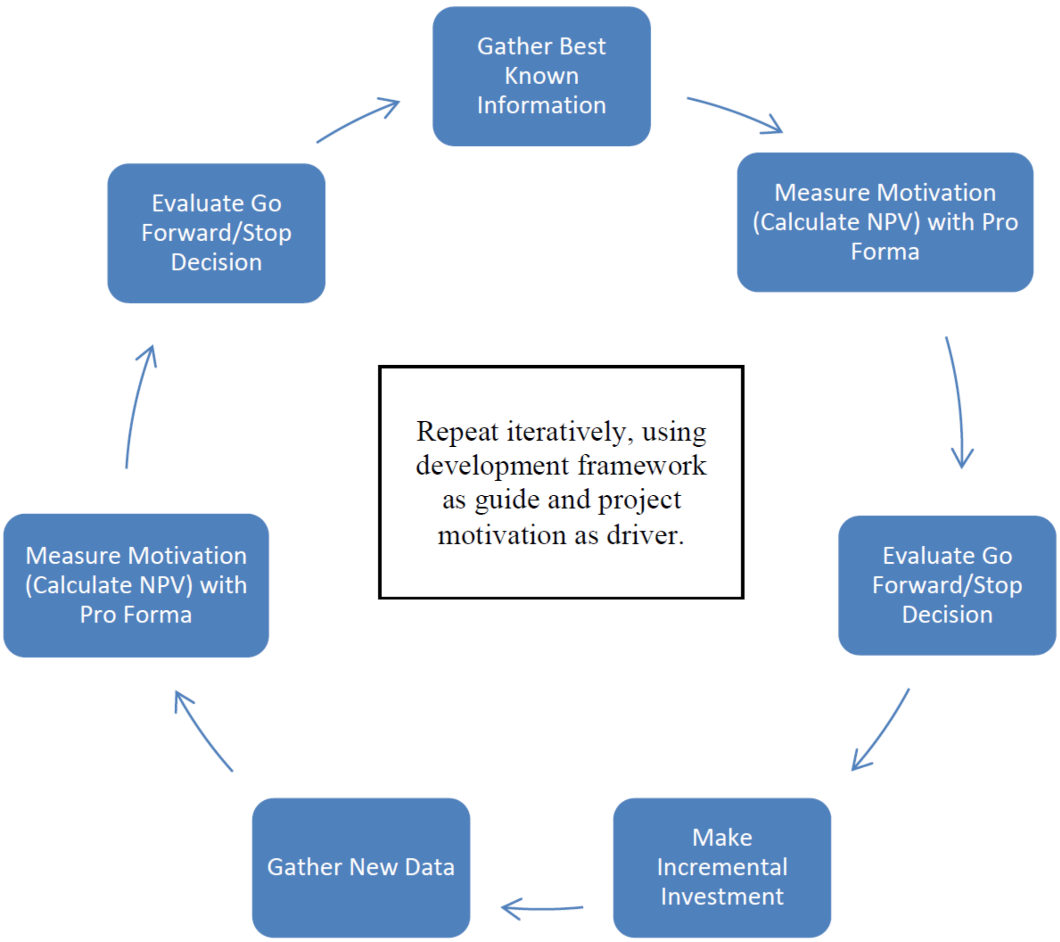
Chapter 4: Testing the Business Case for Offshore Wind on the Texas Gulf Coast

METHODOLOGY

Several studies exist that test the total possible generating capacity of offshore wind resources in the United States or look into levelized cost analysis comparisons between generation sources. However, in order to test the feasibility of actually developing a wind farm off the Texas Gulf Coast, a hypothetical test project was needed to prove out assumptions and test the competitiveness of a prospective project.

As shown in Figure 13, NREL's "Framework for Project Development in the Renewable Energy Sector" visually depicts the intuitive process a developer would use to narrow down prospective projects.

Figure 13: General Iterative Process Concept in Project Development



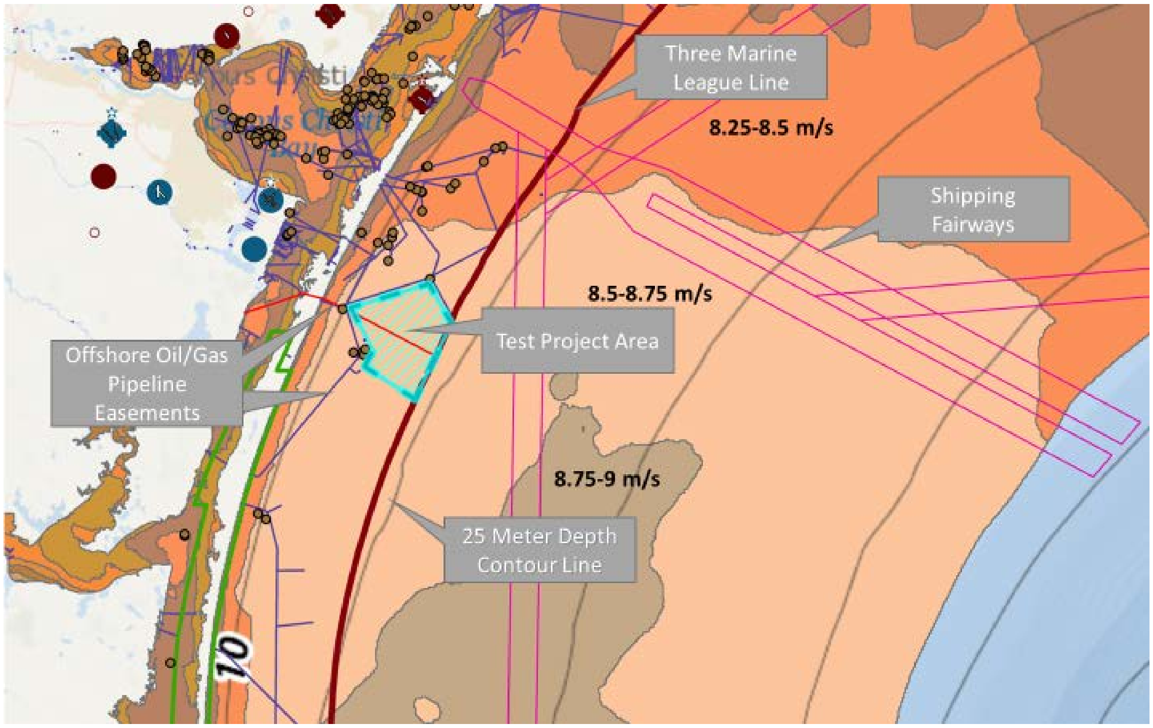
Source: (Springer 2013)

Through this iterative process, a project location was chosen. This hypothetical or "test" project allows for generic inputs from NREL and other sources to be incorporated into a location specific financial model and then tested against local market conditions. While these market conditions fluctuate significantly over both the short and long term, it is possible to specify a reasonable range so that the inputs can be varied as appropriate to test the overall viability of a project.

A firm's decision to invest in an offshore wind farm on the Texas Gulf coast will rely on finding economic opportunity in a regulatory environment that will allow development. The purpose here is not to discern whether or not this specific project area is suitable, but to determine if a suitable combination of resource, topography, market, and regulatory characteristics exists on the Texas Gulf Coast, and if not, what conditions are needed to make development feasible.

As previously depicted in Figure 11: Texas 90 m Offshore Wind Speed, the area just south of Corpus Christi Bay provides the highest wind potential as estimated by NREL at a 90 m hub height, and serves as a starting point to identify a suitable site. Winds in this area average 8.5-9 m/s, comparable to some of the best wind resources in the Texas Panhandle and Great Plains wind corridor (NREL 2019). This area is also bisected by offshore oil and gas pipeline easements and platforms, and it was assumed that future wind leases would have to avoid these areas. Cross-referencing this resource area against other constraints yields a suitable test project area depicted in Figure 14.

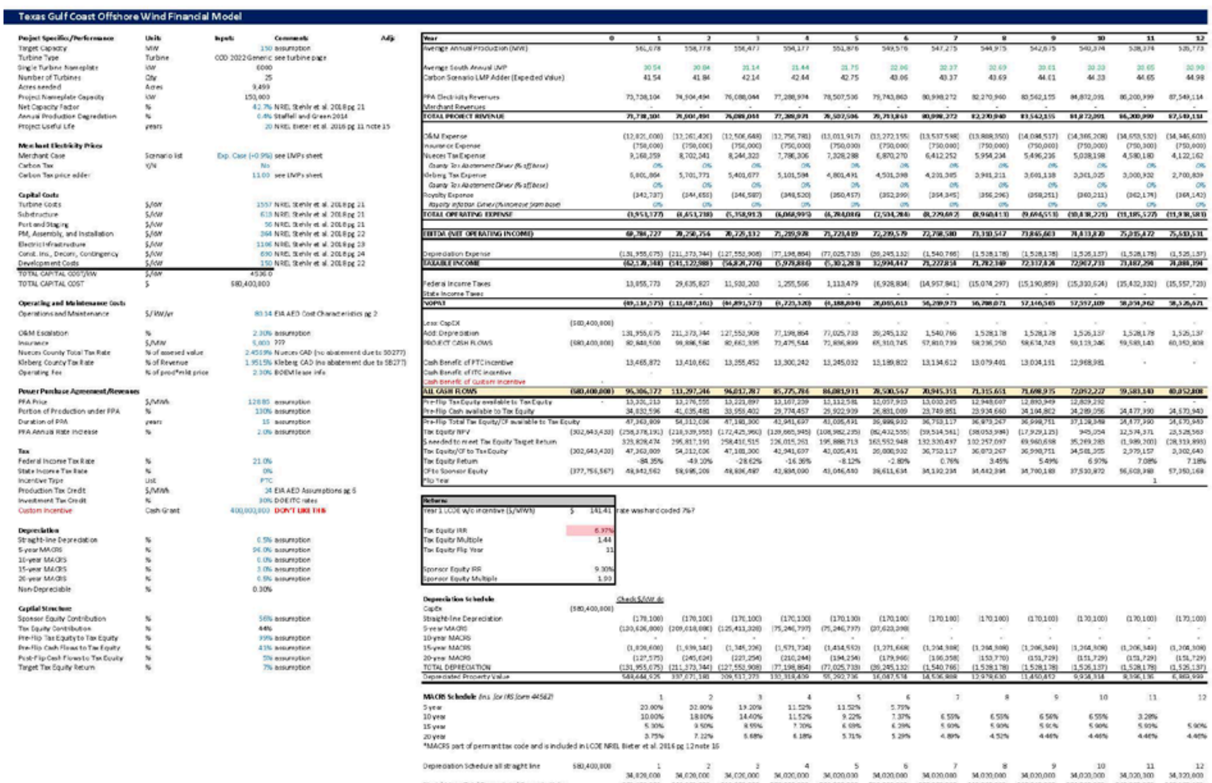
Figure 14: Test Project Area



This area contains approximately 37,000 acres that meet the minimum economic wind speed and are in water depths of less than 30 meters (the average in this area is less than 25 meters). It also remains within Texas state-owned submerged lands (inside the Three Marine League Line), avoiding the federal leasing process. While this is certainly an effort to "cherry pick" what seems to be the best location, that is precisely where a prospective developer would start their search. Additionally, if an offshore wind farm is not economically viable here, it is unlikely to be viable anywhere else along the Texas Gulf Coast. A much more detailed location study would need to be performed to validate this precise location as a viable development option; however, a cursory map search/cross-referencing effort is sufficient to illustrate the potential for development off the Texas Gulf Coast as well as provide meaningful inputs for cost and production estimation. If chosen to move forward, a long term (and costly) wind condition study with semi-permanent meteorological towers would be required to validate resource assumptions.

With a test project area identified, its economic feasibility can be measured using a Discounted Cash Flow (DCF) model as illustrated in Figure 15 and provided as Appendix A.

Figure 15: Offshore Wind DCF Model



See Appendix A for DCF Model

A DCF model was chosen as the main method of evaluating the economic feasibility of this project for several reasons:

1. Simplicity-While there are a large number of inputs, this type of model breaks down evaluation process into reasonable estimates and assumptions that can be combined and evaluated as a whole.
2. Flexibility-DCF models allow for the ability to vary inputs that are uncertain and track outcomes that vary based on different sets of assumptions.
3. Replicability-Though not the only type of financial model used for these kinds of projects, DCF models are well understood and are considered a standard method for evaluating wind projects.

DATA

Site and Market Characteristics

At 37,000 acres, the test project area is not particularly large as compared to other sites under development in both the US and Europe (recent leases on the east coast have been signed for 80,000 acres or more (Chesto 2018)), but it is large enough to develop a project of reasonable size. It is bounded/reduced by several factors:

- The Three Marine League Line: As defined by the GLO and previously described, this line depicts the limit of Texas state submerged lands. Leases in this area would be made with the GLO and avoid a number of federal permitting complications.
- <=30 meters depth: 30 meters is identified as approaching the limit for simple monopile foundation designs as well as the max operating depth for smaller installation vessels (Beiter, Musial, et al. 2016, 59). Fixed substructure installation is possible in much deeper depths, but for simplicity and cost-savings, the 30-meter limit was chosen for this test

project. Due to the other site limitations, the actual depth in the area is all less than 25 meters, which should help project economics.

- Shipping Fairways: Corpus Christi is home to significant port facilities, and obstruction of shipping fairways is prohibited. While shipping routes exist in the general area, they did not affect the test project.
- National Seashore Park Boundaries: Padre Island National Seashore is situated on the barrier island just south of Corpus Christi Bay. Though offshore oil and gas facilities exist off the coast of the National Seashore, the northern seaward border of the park boundary was chosen as the test project's southern limiting factor to avoid public opposition.
- Existing Oil and Gas Pipeline Easements: Several easements are depicted in the area, and it was assumed that it would be necessary to avoid these areas when siting wind turbines.

Since Texas county boundaries and taxing authorities extend to state submerged lands, and the test site is split at approximately 55/45 percent between Nueces and Kleberg counties respectively. The modeling assumptions assume the same 55/45 ratio when calculating taxes.

Access to appropriately sized transmission facilities with available additional capacity is a make-or-break criterion for all generation projects. While additional build-out is not out of the question, the slim margins renewables projects operate under do not allow for significant transmission expenditures. Though there are several major transmission facilities on the mainland in the vicinity of where the test project's undersea transmission cables could be routed, transmission infrastructure information is sensitive in nature, and a detailed transmission capacity study is beyond the scope of this study. Therefore, it was assumed that adequate transmission infrastructure with available capacity is available with reasonable interconnection costs.

Wholesale Electricity Market

This test project is within the ERCOT South Zone. Projects in this zone have access to historically higher than statewide average prices (Potomac Economics 2018, iii). They also have the benefit of reduced congestion issues and direct ties to coastal load centers. This avoids a major issue facing Panhandle and West Texas onshore projects where transmission bottlenecks stifle access to load centers in the Central and East Texas and sometimes push market prices to zero or negative.

Wholesale market prices for the project were projected based on the most recently available South Zone weighted average prices (Potomac Economics 2018, iii). This baseline price was then run against three scenarios:

- Flat prices: no annual change/40% probability
- Increasing: +3.5% per year/35% probability
- Decreasing: -1% probability/25% probability

Anyone with a view on long term market prices would likely utilize different rates and probabilities, and the base model can accommodate those changes. Generally increasing prices, common in industries where increasing regulation and labor costs drive up the cost of production, is a likely scenario with an assumed probability of 35%. However, given recent ERCOT market prices trending lower (Potomac Economics 2018, iii), lower for longer natural gas price outlooks (EIA 2019a, 73), and the general competitiveness of the ERCOT wholesale market, flat, or even declining prices are possible. These two scenarios were assumed to occur with a probability of 40% and 25%, respectively. A weighted average of those scenarios yields an expected case of 0.9% annual increase in prices was used for the life of the project as a base case, which is in line with some private market estimates. These values are used as reasonable, but not authoritative, possibilities for future market conditions.

The effect of wholesale market prices is not as direct as it would appear because they only affect project economics while the project operates as a "merchant" plant, selling directly into the day-ahead or real-time market. Like most generators, offshore wind developers require long term Power Purchase Agreements (PPAs) as a prerequisite for moving forward. Prevailing wholesale market prices clearly affect PPA rates, but competition among other generators, conflicting views of long-term market trends, and other factors have significant effects as well. Once these PPA rates are locked in, wholesale market changes have little effect on project revenues during the term of the PPA contract, which can extend for most of the life of the project.

Major Project Assumptions

Due to the complexity of modeling offshore wind development, particularly in the absence of direct supplier pricing information, a number of assumptions were made in order to both simplify the modeling parameters as well as to define base case starting values that could be varied against other assumptions and hypothetical market conditions.

Turbines

The basis of any wind project is the turbines themselves. Dozens of manufacturers offer turbines with nameplate capacities of under 1 MW up to 12 MW (General Electric 2019). Arguments can be made for larger or smaller turbines; however, given that a number other assumptions are taken from various NREL sources, the test project utilizes NREL's Commercial Operating Date (COD) 2022 turbine assumptions (Beiter, Musial, et al. 2016, 15). Given the likely COD of any Texas Gulf Coast offshore project would be much after 2022, the use of larger and more advanced turbines is not unlikely. In the interest of alignment with other assumptions and to avoid complicating this theoretical, early-stage development process, NREL's 2022 baseline turbine assumptions were used (shown in Table 3).

Table 3: Turbine Assumptions

Key Assumptions	**COD**	**2015**	**2022**	**2027**
Turbine Rated Power (MW)		3.4	6	10
Turbine Hub Height (m)		85	100	125
Turbine Rotor Diameter (m)		115	155	205

Source: Adapted from NREL assumptions *(Beiter, Musial, et al. 2016, 15)*

Project useful life was estimated at 20 years, in line with NREL estimates (Beiter, Musial, et al. 2016, 11). Though this is shorter than the 25-30 year expected life estimate for many onshore installations, the offshore environment is much harsher, and long-term additional maintenance becomes cost prohibitive.

Annual production degradation rate estimates vary significantly and are not fully known. Staffel and Green's research on a large sample of many active European offshore wind farms yielded an expected value of -0.4%/year (Staffell and Green 2014) which was used for base case estimates in this study.

Target Project Capacity

A project target capacity of 150 MW as chosen as a sizeable but not excessively large project appropriate for an undeveloped area. Utilizing midrange NREL turbine separation estimates (Beiter, Musial, et al. 2016, 144), a project of this capacity would require approximately 9,500 acres, allowing for array design flexibility and expansion opportunities in the 37,000 acres available in the defined project area.

Net Capacity Factor

Individual turbine and overall project capacity factors are driven by a number of variables such as wind resource, turbine efficiency, and wake losses. A developer seriously considering building in a new resource area would make the investment to install meteorological (met) towers as soon as they have site control in order to gain reasonable assurances that their capacity factor, and therefore production estimates are correct. A number of these details, as well as long-term met tower data, are not available, so an estimated capcity factor of 47.7% from NREL (Stehly, Beiter and Heimiller 2018, 21) for similarly situated projects was used as a baseline.

CAPEX

Capital expenditures are one of, if not the most important, factors in project economics. These costs are drastically higher in offshore installations vs. onshore. Table 4 provides a breakdown of CAPEX cost estimates from NREL's most recent *Cost of Wind Energy Review*, which provides a good set of baseline assumptions for the test project.

Table 4: CAPEX Estimates

Capital Cost	$/kW
Turbine	1557
Substructure	613
Port and Staging	56
PM, Assembly, and Installation	364
Electrical Infrastructure	1,106
Const. Ins., De-commissioning, Contingency	690
Development Costs	150
Total CAPEX/kW	**4,536**
Total CAPEX for 150MW Array	**$680,400,000**

Source: Adapted from NREL 2017 Cost of Wind Energy Review (Stehly, Beiter and Heimiller 2018, 21)

It is important to note that with a 4,536 $/kW baseline estimate, offshore CAPEX is approximately 2.5x onshore CAPEX cost estimates (Stehly, Beiter and Heimiller 2018, 14).

Operations and Maintenance

While not a major driving factor for onshore wind farms, O&M cost are drastically higher offshore. Many different factors affect offshore O&M costs, such as distance from shore, average sea states, reliability factors of the turbines, and availability of trained maintenance personnel. An EIA estimate of $80.14/kW/yr (EIA 2019b, 2) was used as a baseline, which is likely high given the test project's proximity to port facilities and relatively calm sea state. An escalator of 2% per year was included to reflect rising labor costs and increased maintenance requirements as turbines age.

Financial Model Inputs/Assumptions

Taxes and Royalties

This project will be subject to a federal income tax withholding at 21%, and while Texas has no state income tax, it does have significant county, school district, and other local taxes. These rates can be hard to estimate as the local taxing entities have broad authority to provide tax abatements and the local central appraisal district must value the wind farm based on many factors.

Two issues further complicate this project's tax situation. First, it is within 25 miles of Naval Air Station Corpus Christi. While local taxing entities can and usually do offer tax abatements to aid in development, recently passed Texas Senate Bill 277 states that wind farms “may not receive… a tax abatement if, on or after September 1, 2017, a wind-powered energy device is installed or constructed…” within 25 nautical miles of the boundaries of a military aviation facility”. Furthermore, being split between Nueces and Kleberg counties, the project would be taxed based on differing rates (depicted in table 5) depending on what portions of the project fall into which jurisdiction.

In order to estimate tax liabilities, the combined effective tax rate in each county was used at a pro-rata share equal to the proportion of the total project area located in each county.

Table 5: County Tax Rates

County	Combined Annual Tax Rate	Proportion of Project
Nueces	2.4569%	54.8%
Kleberg	1.9515%	45.2%

Source: Nueces and Kleberg County Central Appraisal Districts

GLO royalty rates (paid as a percentage of revenue) are not publicly available. BOEM rates of 2% of revenues (assessed against prevailing wholesale market rates) are used as a proxy.

Incentive Structure/Depreciation

While the US government has chosen to incentivize renewables development strongly, a project off the Texas Gulf Coast built in the coming years would not be eligible for any federal tax incentives. Given the costs, it is not likely that a project would be built without some sort of subsidy. In order to begin to understand what it would take to get a project like this built, the original federal Production Tax Credit (PTC) rate (inflated along the statutory schedule) of 2.4 cents/kWh, was used (Smith, et al. 2018, §5.01), as well as the 30% Investment Tax Credit rate of 30%. This assumes a renewal of these incentives, possibly directed at more experimental renewable projects such as offshore wind.

Capital Structure

The base case analysis was conducted with a capital structure common to wind projects. Investment was split between tax equity and sponsor equity investors, each requiring an 8-9% return. While an NREL report suggests a Weighted Average Cost of

Capital (WACC) of over 10% may be required given the relative riskiness of offshore projects (Beiter, Musial, et al. 2016, 126), this analysis assumes rates more typical of current onshore projects.

CASE ANALYSIS

Given the multitude of possible values and the sheer number of variables, a single estimate would not adequately depict the results of this hypothetical test project. In order to get a more complete view of the possibilities, a number of cases and scenarios were run. While nearly ever variable could be a candidate for separate analysis, only some variables significantly impact returns individually or are likely to vary in a way that is meaningful to the project. A list of these impactful variables was determined and verified through a sensitivity analysis via Precision Tree software.

Figure 16: Sensitivity Analysis of Variable Impacts

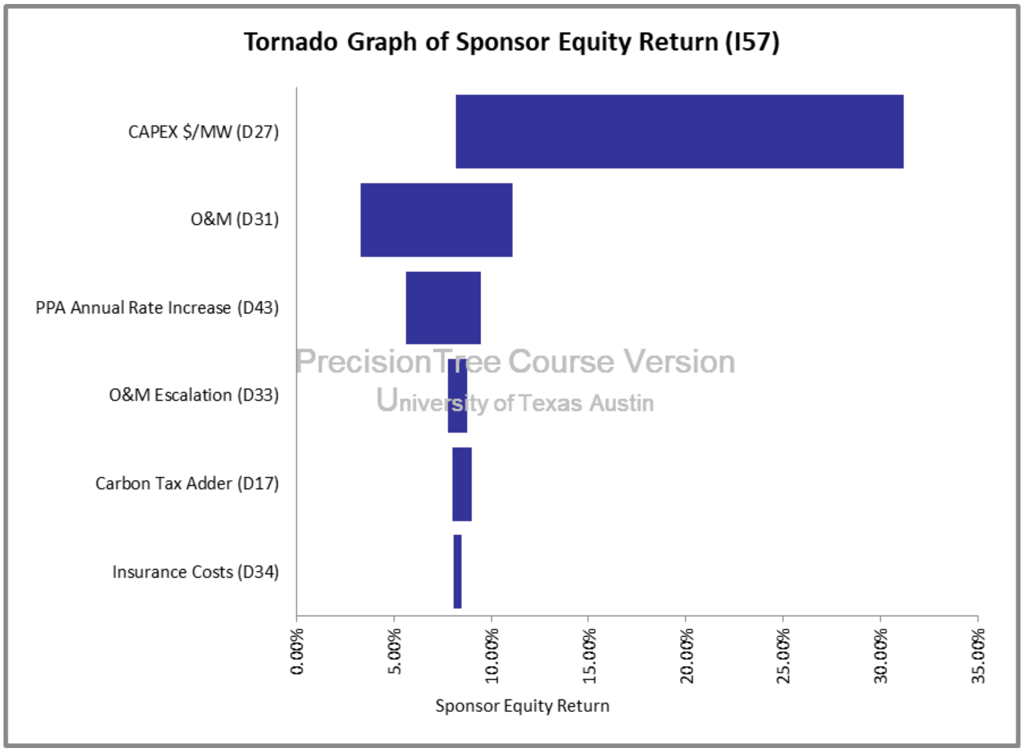


Figure 16 shows the effect of select variables on sponsor returns. While the project model is designed to yield the minimum PPA price with sponsor returns held to a narrow range, the mechanics of the model required the sensitivity analysis to be run against sponsor returns. This indicates both the magnitude and the precedence of the effect of these variables on project economics, which is useful for further testing. The results show that CAPEX is by far the most meaningful variable. Estimates for CAPEX also vary significantly from source to source and are known to be rapidly falling. Because of this, NREL's baseline CAPEX estimates were used as the foundation for case analysis discussed later. Though much less impactful, O&M costs are also important and were tested as well. PPA and O&M escalator rates, and the carbon tax effect on wholesale market prices were less impactful, and are unlikely to vary significantly enough from assumed values to alter the underlying conclusions. Proper benchmarks for insurance costs are not publicly available, but even drastic changes in insurance rates have minimal effect on project returns. See Appendix A for detailed sensitivity analysis results.

PPA Rates and Structure

Generally speaking, the most significant determining factor when deciding to move forward on a renewable energy project is the ability to lock in an economic PPA. For a project to be feasible, it must allow for PPA price that is both competitive in the wholesale electricity market as well as providing for the required returns. For this analysis, capital structure and cash flow allocations were optimized to minimize the required PPA rate via the Excel Solver application, subject to industry requirements or norms for capital structure, cash flow splits, and returns. The PPA term was assumed to be 15 years. While shorter terms are possible, given the risks of this project a longer-term PPA was chosen in order to lock in returns and attract financing. A 2% annual price escalator was also used for the base case, which is not required but commonly used in these agreements. The resulting PPA price was then compared against the mean value for ERCOT South projected wholesale market prices as a proxy for PPA contract prices since PPAs are not publicly available in sufficient quantity to make projections. Comparing calculated PPA rates to wholesale market prices makes it possible to evaluate the potential competitiveness of offshore projects on the Texas Gulf Coast.

Cases

Based on cost estimates, the three cases in Table 6 were constructed: a Baseline Cost Estimate Case, a current Industry Cost Estimate Case, and an Optimistic Cost Estimate Case. These cases were then further divided into regulatory scenarios.

Table 6: Cost Estimate Case and Regulatory Scenario Matrix

<table>
<tr><th></th><th>Baseline Case</th><th>Industry Case</th><th>Optimistic Case</th></tr>
<tr><td rowspan="4">Regulatory Scenarios</td><td>No Incentive
No Carbon Tax
w/ Carbon Tax</td><td>No Incentive
No Carbon Tax
w/ Carbon Tax</td><td>ITC+State RPS
w/ Carbon Tax</td></tr>
<tr><td>PTC
No Carbon Tax
w/ Carbon Tax</td><td>PTC
No Carbon Tax
w/ Carbon Tax</td><td></td></tr>
<tr><td>ITC
No Carbon Tax
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No Carbon Tax
w/ Carbon Tax</td><td></td></tr>
<tr><td>State RPS
No Carbon Tax
w/ Carbon Tax</td><td>State RPS
No Carbon Tax
w/ Carbon Tax</td><td></td></tr>
</table>

Baseline Cost Estimates Case

The Baseline Case utilizes total CAPEX data from NREL of 4,536 $/kW (Stehly, Beiter and Heimiller 2018, 21-24) and O&M cost data from the EIA of 80.14 $/kW/year (EIA 2019b, 2). These estimates represent a conservative starting point for economic analysis.

Current Industry Cost Estimates Case

The Industry Cost Case utilizes offshore wind CAPEX cost estimates of 3,025 $/kW as determined by the investment bank and advisory firm Lazard in their *Levelized Cost of Energy Analysis-Version 12* (Lazard 2018, 10). Lazar's O&M cost estimates generally agreed with EIA estimates, so the same value of 80.14 $/kW/year was used.

Regulatory Scenarios

No Incentive Program

No federal Production Tax Credit (PTC), or Investment Tax Credit (ITC) and no state-level Renewable Portfolio Standard (RPS) Renewable Energy Credit (REC).

Federal Production Tax Credit

Though the window for projects to apply for and receive the PTC is closing, and any new projects on the Texas Gulf Coast are unlikely to meet the deadlines, it is possible that the program may be renewed in one form or another. To evaluate this possibility, a PTC value of 2.4 cents/kWh (the 2017 rate) was applied to the model to determine incentive effectiveness in encouraging offshore wind investment.

Federal Investment Tax Credit

More commonly used for solar projects, the ITC is available for offshore wind as well. Though rates are slated to be stepped down over the coming years, the ITC has also had a long and complicated history of renewals. The full 30% up-front tax credit value was applied to the model for this scenario to test ITC effectiveness.

Hypothetical State Renewable Portfolio Standard

While Texas has a Renewable Portfolio Standard and associated Renewable Energy Credit Program, the state has long surpassed its goals, and the REC market does not factor significantly into the revenues for renewable projects. Some states are experimenting with offshore specific RECs, so it is important to a scenario where the market for offshore specific RECs is a meaningful revenue driver. REC prices vary drastically by markets, so a mid-range levelized REC value of $10 per MWh was applied for this scenario.

Carbon Taxes

Though some states are experimenting with mechanisms to internalize the social cost of carbon for electricity generation, these sorts of carbon policies are not currently being considered in Texas. Any prediction of future federal policy is at best a guessing game. However, it is important to attempt to test the effect of this type of policy. Though the effect of a carbon tax on wholesale electricity markets is indirect and difficult to predict, a carbon tax adder of $11.81/MWh was applied to market prices. This value was calculated based on a 2008 study of multiple price/ton scenarios and their effect on the ERCOT market averaged together and converted to 2019 dollars (Burtraw and Palmer 2008, 826, 835). While certainly a crude estimate, it does provide a starting point for determining the effect of carbon policies on the competitiveness of renewables projects. Each case/incentive combination was tested both with and without this carbon tax adder applied.

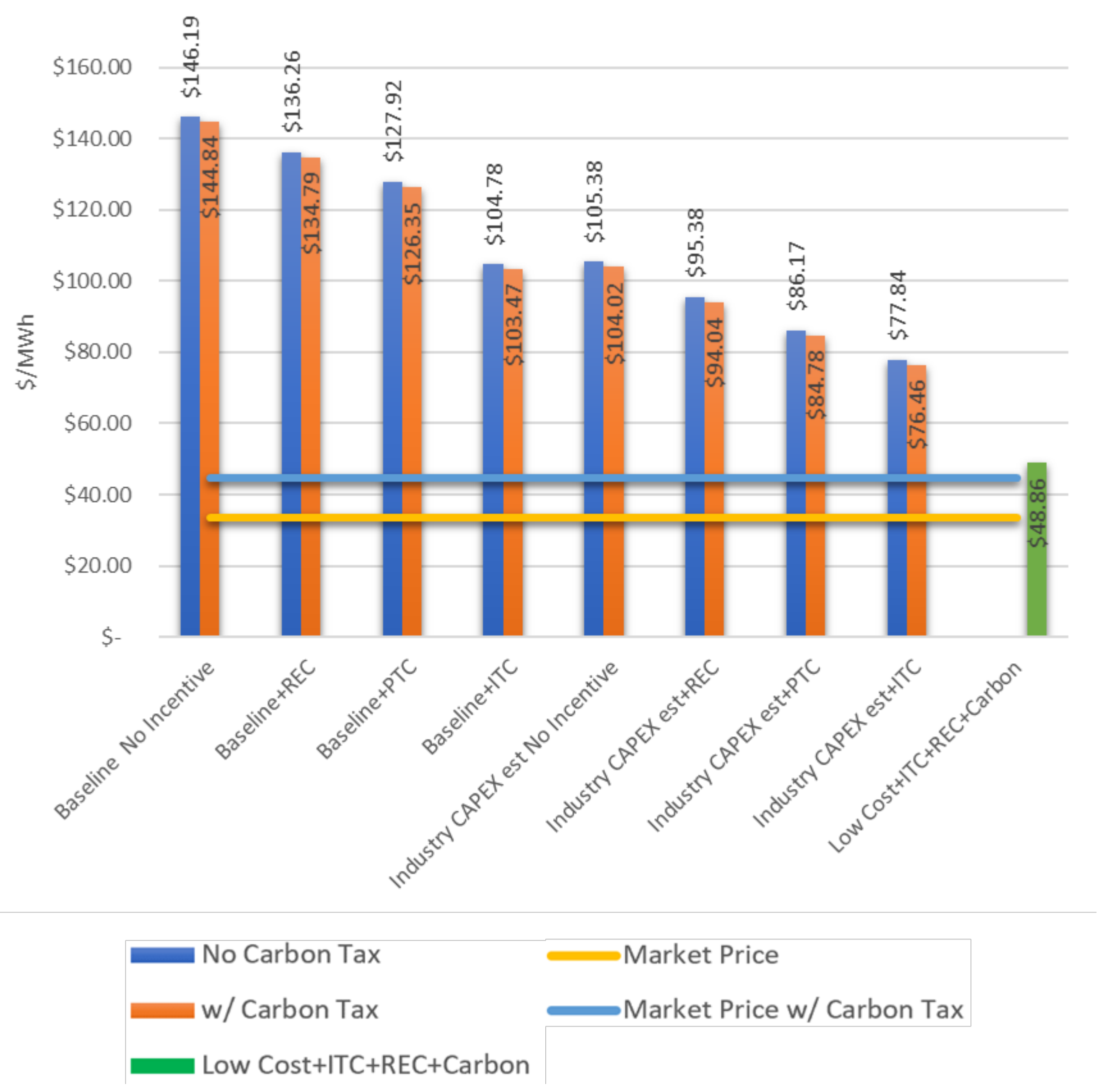
Optimistic Case

As a final analysis, it was useful to put together a "best case scenario" maximizing all factors that improve the competitiveness of a Texas offshore wind project. This "Optimistic Case" helps to determine at what point the combination of cost reductions and regulatory policies make an offshore project competitive in the ERCOT market. To evaluate this scenario, multiple factors were used. Total CAPEX was again taken from Lazard, but the low-end estimate of $2,250/kW was utilized (Lazard 2018, 17). The same O&M cost estimates from the EIA were used but were reduced by 15% to $68.12/kW/year in order to simulate future efficiency improvements. A full ITC value of 30%, as well as the $10/MWh REC value, were also included, as was the carbon tax adder.

Chap 5: Results and Analysis

Overall results show that future Texas Gulf Coast offshore wind projects face significant economic hurdles in reaching cost-competitiveness in the ERCOT market. The results for each case and scenario are summarized below in Figure 17.

Figure 17: Minimum PPA Offerings for each Case and Scenario



The resulting minimum PPA offering for each cost estimate case combined with each incentive scenario are depicted, both with and without a carbon tax applied. Estimated long-term ERCOT South wholesale market prices are also included to show how competitive each case/scenario combination is in the ERCOT market.

BROAD TRENDS

Though the results varied significantly between cases and scenarios, a few broader trends did emerge:

Incentives matter

Though it is obvious that incentives improve project economics, it is useful to point out that, while in many areas renewables (including offshore wind) have become cost competitive without incentives, prices in the ERCOT market are depressed to the point that higher-cost emerging technologies will have a very difficult time competing without the aid of significant incentives.

Carbon policies have little direct effect

A carbon tax adder was initially included in this analysis because it was assumed that carbon policies would have significant effects on PPA offerings. After running the scenarios, it became clear that, given the structure and terms of renewable energy projects and their PPAs, carbon tax effects are minimal. Were a carbon policy already in place at the time of a PPA signing, it may increase the price of that PPA by driving up wholesale market prices. But even this effect depends on what other generating assets are also offering contracts in that PPA market. If an offshore project was on the margins of being competitive, a carbon policy could make the project viable. It is unlikely, however, that a far-out of the money offshore project will become viable even with a large carbon tax value.

Were a carbon policy enacted after a PPA was already under contract (as this model more closely approximates), the increase in wholesale market prices would not affect the project until after the PPA contract expires. While this does translate to higher revenues during the "merchant tail" (the period after the initial PPA expires where a project is expected to be selling into the day-ahead and real-time market), those revenues are far into the future. Once discounted back to today, their effect on project economics is minimal, translating into less than a two dollar difference in minimum PPA offerings in all scenarios at the analyzed rate.

INDIVIDUAL CASE/SCENARIO ANALYSIS

Baseline Cost Estimates No Incentive

As expected, the baseline cost estimate case with no incentives is the least competitive scenario. The minimum feasible PPA (no carbon tax) of $146.19 is far above the $30-35 ERCOT South wholesale market average.

Baseline Cost Estimates + REC

In this theoretical state RPS scenario, each MWh of production yields a REC worth $10, which in turn yields a minimum PPA offering of $136.26 (no carbon tax). A quick sensitivity analysis confirms that in this REC-only scenario, for each dollar of expected REC value, the minimum PPA offering is reduced by about a dollar in a nearly one-for-one fashion. REC markets in certain states have reached as high as $60 in recent years (EPA 2019), which would drastically effect project finances. It is important to note however that this is a grossly simplified REC model. Prices in REC markets are fluid, and it would be unwise, even in a healthy and high-priced market, for a developer to not significantly discount their expected REC revenue due to its exposure to price and policy risk. In this model, REC prices of about $100 would be required to bring PPAs in line with the ERCOT price forecast, which are not expected to occur.

Baseline Cost Estimates + PTC

Applying a full PTC value of 2.4 cents/kWh does significantly reduce the minimum PPA offer price to $127.92 (no carbon tax), a more than 12% reduction. While the PTC may make a project feasible in other markets, it is clear that the level of PTC incentive necessary to make this project with these costs competitive in the ERCOT market is unrealistic.

Baseline Cost Estimates + ITC

Though the PTC is more commonly utilized by onshore wind projects which are characterized by relatively low CAPEX and high production, the higher CAPEX levels for offshore projects make the ITC much more valuable. In this case/scenario, the ITC lowers the minimum PPA offering to $104.78 (no carbon tax), an over 28% reduction. In all of the case/scenario combinations tested, the ITC by far the most effective incentive mechanism, but resulting PPA prices remain well above the ERCOT South average.

Industry Cost Estimates No Incentive

Publicly available industry CAPEX estimates are significantly lower than NREL figures. With the estimates used in this analysis and with no incentives applied, the minimum PPA offerings are reduced from baseline estimates by nearly a third to $105.38 (in the "no carbon tax" case).

Industry Cost Estimates + REC

Similar to the base case + REC combination, the addition of a REC incentive yields an approximately one-for-one reduction in the minimum PPA offering under these parameters. A $10 expected REC value brings the minimum PPA offering to $95.38 (without a carbon tax).

Industry Cost Estimates + PTC

The addition of tax incentives yields a required PPA of $86.17 in the industry case, which is much more in line with recently announced US offshore wind PPAs (Bade 2018). At this price, an offshore wind project with these costs and incentives could be cost competitive in many US markets, though it still does not compete well in the ERCOT market.

Industry Cost Estimates + ITC

Again, the ITC is found to be the most valuable incentive program tested. Industry cost estimates + the ITC brings the minimum PPA offering value down to $77.84 (without a carbon tax).

Optimistic Cost Case + ITC + REC

The previous analyses were designed to estimate the impact of each parameter in an independent sense. However, in practice, it is much more likely that multiple factors will simultaneously affect key outcomes. To test the impact of future cost improvements, an optimistic cost estimate + ITC + REC case/scenario combination was run that featured low-end industry CAPEX estimates, predicted efficiency gains in O&M spending, utilized the most effective tax incentive (the ITC), and a $10 expected value for RECs. This combination tests an optimistic, but not unrealistic, hypothetical future scenario. At the tested values, a Texas offshore wind project could offer a PPA at $48.86 (including a carbon tax). While still slightly above the carbon tax-included market price estimate of $44.54 used in this analysis, the prospects for future offshore development in Texas become much more interesting under this scenario.

Chapter 6: Conclusion

This analysis is not meant to describe an exact project size or a specific location that should be developed. Nor do the parameters, scenarios, or even the methodology used represent the only mechanisms one might use when testing the economic feasibility of an offshore wind project on the Texas Gulf Coast. It is meant to be an illustrative representation of the relative competitiveness of offshore wind in Texas. However, the results of this analysis do yield some interesting and broadly applicable findings.

First, while offshore wind in Texas has some valuable advantages, under current cost, market, and regulatory conditions, offshore wind does not stack up economically compared to other more mature and readily available methods of generation in the ERCOT region. In a future of reduced costs and significant regulatory incentivization, it is not altogether unlikely that a combination of these factors and changing market conditions could make offshore wind on the Texas Gulf Coast a possibility.

Second, as expected, this analysis confirms an important finding that, given its higher upfront costs, offshore wind projects are likely to benefit more from the ITC than the PTC. This is important when considering the future of federal tax incentives. Though it can be criticized for incentivizing spending and not the actual production of renewable energy, the ITC has proven to be an effective mechanism for encouraging renewables development. Before both the PTC and ITC sunset for wind projects in the next few years, it is likely that the ITC will continue to help the offshore wind industry in the US reach cost competitiveness, even as the benefit rates are reduced. However, it may be important for policymakers to either forgo the phase-out of the ITC or renew it in such a way that it benefits less mature technologies, including offshore wind.

Additionally, though offshore wind and likely any renewables developers would almost certainly support some type of carbon pricing mechanism, the effects of such a program are indirect and not nearly as meaningful as expected. The price on carbon that would be required to have a more direct and significant effect on offshore wind competitiveness would need to be much higher than is likely to be seen in the current political environment; if one were to be approved at all.

NOTE ON ASSUMPTIONS, CONCERNS, AND AREAS FOR ADDITIONAL RESEARCH

Since this analysis was done to provide a generalized and illustrative assessment of the economics of offshore wind on the Texas Gulf Coast, only publicly available data was used, and a number of simplifying assumptions were made. A case-by-case analysis utilizing privately negotiated cost estimates, return requirements, and future market expectations would be required before any prospective developer or interested party could move forward on a project or related matter. This analysis serves as an initial step in considering the pursuit of individual projects.

For the hypothetical test project itself, several concerns which were outside the scope of this analysis were largely ignored. The hurricane risk in the Gulf is much higher than in other places, which could drastically affect insurance rates, maintenance, turbine costs, and other factors. Migratory birds, prevalent in the area, also bring about a number of environmental concerns and restrictions that could affect offshore wind's prospects in the area.

As a relatively new area of interest, the body of research on offshore wind in the US is not as mature as other generation sources. Though the issues of public perception and opposition in Texas are likely less of an issue than in other states, these were not addressed in this analysis and could be the subject of their own study. A more current and market-specific study on the expected effects of carbon pricing policies on wholesale electricity markets could also be both interesting and useful for developers and policymakers alike.

Appendix A

See supporting documents for DCF Model in excel format

Glossary

BOEM	Bureau of Ocean Energy Management
CAPEX	Capital Expenditures
COD	Commercial Operating Date
CWA	Clean Water Act
CZMP	Coastal Zone Management Plan
DCF	Discounted Cash Flow
DOE	Department of Energy
DOI	Department of the Interior
DOL	Department of Labor
DOT	Department of Transportation
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas (Independent System Operator serving most of Texas)
FAA	Federal Aviation Administration
FWS	Fish and Wildlife Service
GLO	General Land Office (Texas state agency charged with stewardship of state-owned lands and natural resources)
GW	Gigawatt
GWh	Gigawatt hour

ISO	Independent System Operator
ITC	Investment Tax Credit
kW	Kilowatt
kWh	Kilowatt hour
LSE	Load Serving Entity
MET Tower	Meteorological Tower (large, semi-permanent weather stations installed in project areas to verify wind resource and conditions)
MW	Megawatt
MWH	Megawatt hour
NEPA	National Environmental Policy Act
NIMBY	Not In My Back Yard
NMFS	National Marine Fisheries Service
NMI	Nautical Mile
NPS	National Park Service
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
OSHA	Occupational Safety and Health Administration
PPA	Power Purchase Agreement
PTC	Production Tax Credit
PUC	Public Utility Commission
REC	Renewable Energy Credit

RFP	Request for Proposal
ROW	Right-of-Way
RPS	Renewable Portfolio Standard
TSP	Transmission Service Provider
USGC	United States Coast Guard
WACC	Weighted Average Cost of Capital

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