Offshore Wind Procurement Options for Delaware

Report to the State of Delaware by the

Special Initiative on Offshore Wind at the University of Delaware

Authors

Willett Kempton, Technical Advisor, SIOW; Professor, University of Delaware
Lillian E. Peterson, Honors Program, University of Delaware
Amy Bosteels, Marine Policy, University of Delaware
Kris Ohleth, Director, SIOW

27 Feb 2022
Corrections 6 March & 8 April 2022

Burbo Bank offshore wind farm, Liverpool Bay, England —Getty Images

University of Delaware | College of Earth, Ocean, & Environment
SPECIAL INITIATIVE ON OFFSHORE WIND

Advisors and contributors to this study

Todd L. Goodman, Attorney, Phillips, McLaughlin & Hall
Jason J. Folsom, Aker Solutions
Stephanie A. McClellan, PhD, Simply Blue Group; and Founder of SIOW
Deniz Ozkan, PhD, Invenergy

Peer Reviewers

Note: Some reviewers have reviewed only specific sections; review does not constitute endorsement.

Samual Beirne, Energy Program Manager, Maryland Energy Administration
Philipp Beiter, Senior Offshore Wind Economic Analyst, National Renewable Energy Lab
Amanda Best, Senior Commission Advisor, Maryland Public Service Commission
Josh Kaplowitz, Vice President—Offshore Wind, American Clean Power Association
Walter Musial, Offshore Wind Platform Lead, National Renewable Energy Lab
Gary Norton, Consultant, Office of Energy Efficiency and Renewable Energy, US Dept. of Energy
Sara Parkison, Knauss Fellow, Bureau of Ocean Energy Management, US Dept. of Interior
Erich Stephens, Founding CEO, Vineyard Wind
Marian Swain, Deputy Director of Policy and Planning, Massachusetts Dept. of Energy Resources
Gabe Tabak, Counsel, American Clean Power Association

About the Special Initiative on Offshore Wind

The Special Initiative on Offshore Wind is an independent project at the University of Delaware's College of Earth, Ocean and Environment that supports the advancement of offshore wind as part of a comprehensive solution to the most pressing energy problems facing the United States. The Special Initiative on Offshore Wind provides expertise, analysis, information sharing, and strategic partnership with industry, advocacy and government stakeholders to build understanding and drive the deployment of offshore wind.

Acknowledgments, Funding, Disclosures

The Rockefeller Brothers Fund provides ongoing support to the SIOW, including funding to prepare this study. We are grateful to the many advisors, contributors, and reviewers who donated their time, including data and recommendations from DNREC. Kempton, the study's lead author, has managed UD research funding in several areas related to this study, from the Office of Economic Innovation and Partnerships to study marshaling ports on the East Coast and has applied for funding to UD for the study and design of two offshore wind facilities (a marshaling port and a training center) but he has no financial interest in any topics in this report.

Available from

SIOW publicatons: https://sites.udel.edu/ceoe-siow/publications/
Filename: DE-OSWProcurement-SIOW-27Feb2022.pdf

Table of Contents

Executive summary

To date, 14,000 megawatts (MW) of offshore wind power projects have been awarded, the first of US state requirements totaling 40,000 MW by 2040 (Parkison & Kempton 2022). Substantial technology advancements and the in-progress American industrial scale-up of this industry have dramatically reduced the cost of electricity from offshore wind in recent years. The buildout of the anticipated offshore wind projects through 2035, now required by eight Eastern Seaboard states, will result in expenditures on components, installations, and operations through 2035, estimated to be $109 billion (SIOW 2021), creating 45,000 to 83,000 jobs (AWEA 2020).

In response to interest from Delaware state government and citizens, the Special Initiative on Offshore Wind (SIOW) has prepared this report, providing an analysis of the anticipated price of electricity from offshore wind power as well as guidance and options for the state if it decides to initiate a procurement process.

In **Part I**, we project the price of offshore wind for Delaware using three analytical methods: 1) examining recent US offshore wind power contract prices, 2) taking expert forecasts of expected price reductions and applying them to the recent contract prices, and 3) using a bottom-up model based on component prices for future projects. We then compare these projected offshore wind prices with recent wholesale purchases of today's power sources by Delmarva Power. For valid comparisons, all prices are made comparable and converted to 2021 dollars. This comparison is shown in Figure ES-1.

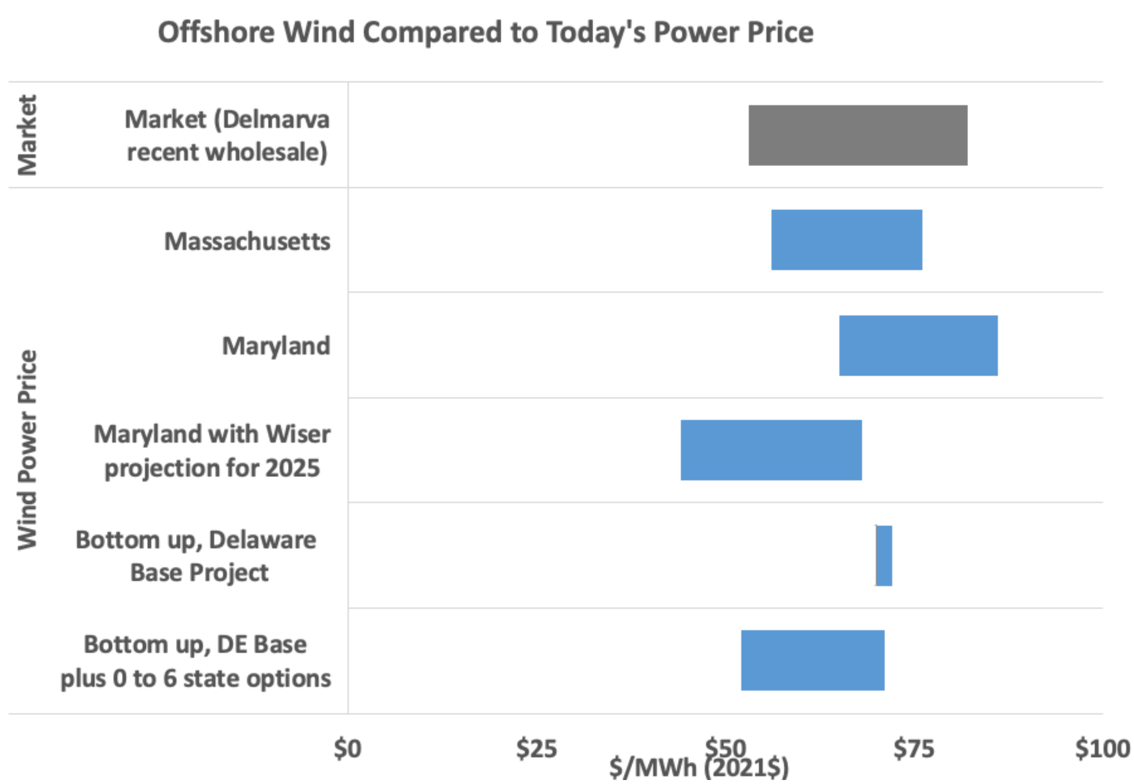

Figure ES-1. Delaware price of market electricity, mostly natural gas (top bar, grey) compared with three methods for estimating future offshore wind prices (blue bars). All prices are $/MWh normalized to 2021$. (This figure is simplified from Figure 2 in the full report.)

We also calculate the health cost and carbon cost, based on federal guidance, of offshore wind in comparison to our regional power mix. This is not a policy proposal, but a calculation so that external costs can be considered as a quantitative benchmark, if desired.

We compare offshore wind contracts across five US states, to illustrate the factors affecting power prices. Lower prices result from more recent projects, turbines of 10 MW or larger, projects of at least 800 MW in size, and bid evaluations prioritizing least cost.

Part I concludes:

- Two East Coast comparison states that recently approved offshore wind contracts (Maryland and Massachusetts) yielded prices from $56 to $86/MWh.
- Projects of at least 800 MW capacity have contracted to sell power at considerably lower prices than smaller projects.
- A hypothetical 800 MW project off of Delaware's coast, modeled for this report using a standard bottom-up price calculation tool (CREST) and assuming power beginning December 2027, yields $71.48/MWh.
- Recent wholesale power purchases by Delmarva range from $53 to $82/MWh.
- Therefore, today's US offshore wind power prices fall within the range of wholesale power being purchased for Delaware now. (No state subsidy nor external cost is used in this price comparison, nor is one required for an offshore wind procurement.)
- The Federal government now provides financial cost guidance for health and climate change damage. When added to the market costs of both offshore wind power and today's conventional power, the result shows that offshore wind power is less than ½ the total social cost of Delaware's electricity today.

In **Part II**, we draw on the state-initiated procurement processes of other eastern seaboard states, and explain the entities involved and a flowchart of their process and decision points. We then outline a process that Delaware could initiate to procure favorable bids for offshore wind power. The process includes creating an offshore-wind specific solicitation using a tailored Request for Proposals (RFP), choosing RFP requirements, and prioritizing evaluation criteria for bids received. This report also models the estimated price impact (reduction or increase) of potential state actions or policies, including RFP requirements, procurement-associated policies, and job-creating actions. We do so noting that different approaches have been taken by the coastal states north and south of Delaware, yielding different prices and benefits. Some states have leaned more toward a "state economic benefits" approach and others have taken a "lowest offshore wind price" approach. If Delaware decides to create a procurement for offshore wind, the state will develop its own approach based on its priorities, probably in the form of a procurement law. The electricity price impacts of these choices are calculated by this report to clarify the price impact of the possible policies and alternative priorities.

For price reduction actions, this report describes nine actions or policies that will reduce the price of offshore wind power, and two actions to avoid that would increase the price. The potential cost-reducing actions by the state are:

- Set up the procurement to use a Power Purchase Agreement (PPA) and to prevent any imputed debt implications for the utilities buying power
- Specify in the RFP that the primary criterion for bid evaluation is low power price
- Encourage more than one Delaware utility to be the offtaker
- Encourage the Bureau of Ocean Energy Management (BOEM) to create more leases near Delaware, as part of the current Central Atlantic stakeholder process

- Create a defined, predictable state process to permit a cable landing from the ocean to the Delaware electric power system
- Coordinate with Maryland on a single transmission corridor for MD & DE projects to lower cost and environmental/community impact
- Review and provide early guidance to developers on compliance with Delaware permitting (this would be performed by DNREC)
- State installation of a meteorological buoy in likely near-Delaware lease areas, prior to the RFP

For six of these price-reducing actions, the resulting reduction in the price of electricity is calculated. The price reduction achieved by successfully implementing from 0 to all 6 actions ranges from $0 to $19.17/MWh, resulting in the range of prices shown as the lowest bar in figure ES-1.

We describe a second list of optional actions that Delaware may consider to create jobs, new industries, and new markets for Delaware businesses. These state options range from requirements in the RFP, separate administrative or legislative actions, to requirements upon the developer. Independently of the actions below, some job creation is more likely once a procurement process has been initiated, without any other explicit action or cost, simply because Delaware would have a state-approved process leading to an offshore wind project. Optional actions are as follows:

- State requires that the developer's O&M port be located in Delaware
- State encourages private investment to build a Delaware Bay marshaling port
- Developer contributes to a large job-creating facility, like a wind component factory
- State or developer facilitates the creation of a wind worker training center
- Developer builds offshore wind visitor center

The report estimates the costs of each of the job creation actions and their impact on electricity price if the developer pays that cost. Job-creating options range widely in cost. Some have no budget cost but may require some targeted planning or minor actions by existing state staff. Those actions that require developer payments range in wholesale cost increases from under $0.01/MWh to $3.40/MWh, with the cost unrelated to number of jobs; for example, one of the largest job creation actions is estimated to raise cost by only $0.60/MWh. That is, contrary to widespread perception, there is not a strong correlation between spending more money (tax or ratepayer cost) and creating more employment in this industry.

We briefly consider longer range options if the state decides to expand after the one offshore wind project considered here. Beyond one project, a joint Maryland-Delaware power line could be built for expandability, so that Sussex County substations could develop into transmission through-connectors. If the Delaware offshore wind project is successful, the procurement process used for the first project can be repeated for subsequent projects. With expansion of offshore wind and its large-scale clean electricity supply, we outline synergistic industries for clean fuels, such as hydrogen electrolysis, ammonia from hydrogen, fertilizer and e-fuels production, electrification of cars and appliances, and other energy uses.

In the nearer term, with an efficient procurement process, competitive bids, and a proposal evaluation emphasizing least-cost, by 2027 Delaware could have substantial power from offshore wind and associated new businesses. The first project alone would meet the state's current legislative requirements for RECs by 2027 in a single project, at a price within the range of recent prices of traditional power. That project would also reduce Delaware's CO_2 emissions from the power sector by 28%, create new jobs, and would likely create new companies and business opportunities.

Objectives

The Special Initiative on Offshore Wind (SIOW) has previously conducted studies regarding offshore wind (OSW) procurements for New York State (McClellan et al. 2015) and for the Commonwealth of Massachusetts (Kempton et al. 2016). Those SIOW studies provided information on the cost of electricity from offshore wind power and how those states could structure procurements to reduce the cost to their electricity consumers. As demonstrated by those reports, the SIOW provides independent, peer-reviewed, factual information to facilitate informed choices by state decision-makers.

The present report responds to discussions with the Delaware Department of Natural Resources and Environmental Control (DNREC) and the Delaware General Assembly (GA) with regard to offshore wind power. The objectives of the present report are guided by the following communications:

- DNREC Secretary Garvin stated that “DNREC would like to work with the SIOW to convene staff and industry experts to conduct analysis of market trends, forward looking prices, supply chain and workforce development opportunities, technical obstacles, and options for the possible procurement of offshore wind to serve Delaware” (Letter of 14 April 2021).
- The Chair and Co-chair of the Senate Environment and Energy Committee and the Chair and Co-chair of the House Energy Committee jointly wrote SIOW to encourage a “study of potential power solicitation, and options for such a procurement.” (letter of 5 May 2021)

SIOW drew from these letters, discussions with interested members of the General Assembly and Administration, discussions with citizen groups, and our prior experience to set this report’s objectives:

- Provide an overview of the process of OSW procurement and why that is different from procuring other electricity sources,
- Anticipate the likely cost of electricity from OSW based on the best information currently available,
- Explain how a process for procurement has worked in other states, and make Delaware-specific recommendations for a solicitation process,
- Provide a basis for multiple options the State could choose among in a solicitation, including choices to emphasize different objectives, such as:
  - Lowering or at least not raising the cost of electricity,
  - Reducing CO_2 emissions and criteria pollutants, and
  - Improving the likelihood of state economic growth and job creation.

As there could be some tradeoffs between the price of electricity and other objectives, this report describes potential policies and opportunities and quantifies their relative effect on the price of electricity.

Some questions frequently asked about offshore wind projects—the technology, environmental impacts, where to bring the power to shore, connecting to the regional power grid, consultation with affected communities, aesthetic impacts, etc.—are outside the scope of this report. These will be addressed by legally-required state and federal reviews and approvals before any project can be built (for a readable summary of requirements, see Vann 2021). The goal of this report is to inform a state decision of whether to initiate a process so that offshore wind could be purchased for sale to Delaware utilities. Other questions and concerns will necessarily be resolved later in the process, as they have been in other states.

Part I: State of the market and anticipated power price

Part I will provide a brief background, an overview of the terminology in this report, and an update on the offshore wind market in the US. Three methods for predicting the future price of offshore wind are explained, then the expected price of offshore wind is compared to recent wholesale electricity market prices.

State of the US offshore wind market in 2022

Background & electricity units

Offshore wind is a local resource for generating electricity. In the mid-Atlantic region, it is an alternative to producing electricity from natural gas, coal, nuclear, solar, and land-based wind. Within the past 2-6 years, the cost of offshore wind power has dropped dramatically (Lazard 2020). More electricity generation is needed in the Mid-Atlantic region because many old coal and nuclear plants are reaching their end of life and because cars and other devices are increasingly electric. Due to environmental and climate concerns, as well as the lower costs of renewable power, renewable electricity now dominates new power generation capacity additions nationally.[1]

Offshore wind commitments are growing rapidly in our region. Eastern Seaboard states between Massachusetts and North Carolina have collectively committed by state law to 39,880 MW of offshore wind generation, including over 14,000 of that already under contract as of October 2021 (Parkison & Kempton 2022, Table 3). This industry will require $109B investment in supply chain components and services through 2030 (SIOW 2021), the factories, ports and boats to produce that, and will create 45,000 to 83,000 new jobs, with continued growth expected after 2030 (AWEA, 2020).

We next define electricity units and price concepts used here. Electric generation can be measured by *power plant capacity*, in megawatts (MW), and by *energy production*, in megawatt-hours (MWh). For example, a power plant of 10 MW capacity can produce 10 MW of power at maximum output. If it were run at maximum output for two hours, that plant of 10 MW capacity would produce 20 MWh of electric energy. To compare *power plant sizes*, a typical natural gas power plant might be 300 to 500 MW; today's commercial offshore wind plants are 800 to 1200 MW capacity, about the same size as a nuclear or large coal power plant.

Regarding price units, *wholesale electricity prices* are in dollars per megawatt-hour ($/MWh). The *retail price* units are smaller, cents/kilowatt-hour, or ¢/kWh.[2] By convention, the *capital cost*

---

[1] In 2020, wind plus solar capacity was 76% of new generation, while natural gas was only 22% (EIA 2020). Continuing for 2021, US generation capacity additions are expected to be 70% wind and solar, as opposed to 16% natural gas (EIA 2021). The small amount of natural gas generation capacity that was built in 2021 is predominately in natural-gas producing states, which Delaware is not (EIA 2021).

[2] A simple rule to convert wholesale to retail price is to change wholesale dollars to retail cents and divide by 10. Thus, $70/MWh is the same as 7¢/kWh. The retail customer pays for the energy (kWh) plus the cost of distributing that energy; on Delmarva Power bills, energy can be seen as "Standard Offer Service Supply" which is also called "Price to compare." There is an additional "Delivery Charge" on the bill that pays for wires, poles, substations, meter readings, etc. The delivery charge is not affected by decisions regarding the purchase of renewable versus other types of power.

of power plants is measured in dollars per kW ($/kW) of capacity. This report will use $/MWh for wholesale energy cost, and we will use $/kW for the capital cost of electric generation. To relate the costs in this report to home electric bills, the average Delaware residence uses 932 kWh[3] or 0.932 MWh per month, and an 800 MW project would make up 33% of the electricity going to Delaware's customers. For example, if a specific policy change would lower or raise wholesale electricity by $1/MWh, that is a 31¢/month (0.932*0.33) saving or cost in the average Delaware home's monthly bill, or $3.69 per year.

In order to compare the cost of electricity across different types of fuels and technologies, price of electricity is sometimes calculated as *levelized cost of energy* (LCOE). LCOE allows comparing price despite different streams of costs and revenue through time. Because we will be comparing projects with a price escalator equal to the projected inflation rate and with future operations and maintenance (O&M) costs included, this report will make electric price comparisons using *power purchase agreement price*, or *PPA price* rather than an LCOE price. Typically the PPA price, also called the "Year-One Cost of Energy" is the price paid per MWh the first year of operation, as specified on the PPA; it's a tangible quantity and, in our view, is more readily understandable. (The cost comparisons made here are valid and lead to the same decisions, whether LCOE or PPA is used as the price metric.)

Why procurements are tailored for offshore wind power

As the United States and the world transition from fossil fuel-generated power to renewable power, our understanding of electricity purchase procedures also changes. The states that have procured OSW, or are in the process of procuring it, have generally begun with either a procurement law or executive authority followed by a procurement law.[4] This section explains why offshore wind requires a somewhat different approach from existing frameworks for fossil fuel generation and from smaller-scale renewables. This section also explains how lower cost per MWh can be achieved, by both learning from other NE states, while also tailoring the procurement process to Delaware's specific circumstances.

It's helpful to start with fundamental differences in the cost of fuel-driven versus renewable generation. The cost of electricity is determined by capital cost for the generation plant and operating cost for fuel plus O&M. Fuel prices fluctuate greatly, and fuel has traditionally been the largest part of electricity costs. Renewables require more capital cost up front but their fuel is free, O&M is highly predictable (Stehly et al 2020), so operating costs for wind and solar are known in advance and don't fluctuate.[5]

One practical consequence of this is that utilities typically buy power from fossil fuel generation via short-term power contracts, typically 2-3 years, but buy from large-scale renewable sources via long-term contracts, 15 to 25 years. Why? The wind or solar developer takes out a

[3] Source: "Average Electric Bill" updated 20 November 2021, iPropertyManagement, Nov 20, 2021. Last accessed 5 Feb 2022 at: https://ipropertymanagement.com/research/average-electric-bill#delaware

[4] Even in Virginia, the only state so far with a utility taking the lead, the state granted its regulated utilities approval to develop OSW as part of its regulated activity (Code of Virginia, Title 56, Chap 23, § 56-585.1:11). This law also capped OSW projects' total levelized cost to no more than 1.4 times the electricity cost of a simple cycle combustion turbine.

[5] Fossil fuel power plants can reduce fuel cost fluctuations the first few years by buying a financial hedge, or increasingly, by contracting for renewables with a constant price during long-term PPAs. A smaller source of price fluctuations is that towards the end of a project's life, when generation equipment typically requires more maintenance, whether wind or fossil. Turbine maintenance doesn't cause wind power price fluctuations because it is baked into a PPA price, also late-lifecycle maintenance is balanced by capital-cost payoff by that time.

loan to build, and components and contracts are priced before they build. Therefore, they know what the price of electricity must be in year one and for every subsequent year. The fuel-based generator is paying off a smaller loan, but isn't sure what their input fuel costs will be, even a couple of years into operation. The fuel-based generator needs the ability to adjust prices to account for changes in fuel costs, thus the need for short-term contracts.

Conversely, large-scale renewable generation is determined by the ability for private developers to borrow money and then pay it back via electricity sales over 20 to 30 years. If a large wind project, a 30-year asset, sells its output via a short-term contract with no assurance of continuing sales, then the developer won't be able to borrow money, or the borrowing rate will be very costly. This problem is solved if the buyer and seller sign a long-term power purchase agreement (PPA) to sell at a defined rate in $/MWh. To the buyer, this means that the price won't rise unexpectedly due to fuel price increases or carbon taxes in the future. On the other hand, if competing sources of electricity become cheaper, the buyer cannot switch and take advantage of a lower price until the end of the contract period. In summary, short term power purchase contracts make sense for fossil fuel generation, but long-term contracts are possible and will lower the cost of wind power and other renewables.

One often hears that offshore wind power is expensive. Indeed, Table 1 shown below includes some high prices. But as previously stated, larger and newer offshore wind projects generally have lower prices, due to economies of scale and recent technology improvements. Most importantly, as we will see, state policy and state structuring of the procurement can increase or reduce the electricity price. Some states have prioritized low cost electricity, but more have decided to leverage power procurement to pay for job-creating facilities within their states.[6] We have no position on whether low power cost or more job creation is preferred, but this report will inform state decision-making by laying out the options and the cost or saving of each.

A long-term power contract was identified as a way to resolve the problem of risk in repayment of loans for a long-lived investment. Other risks include incorrect prediction of wind speed (and thus revenue), development delay, unpredictable permitting outcomes, construction delay. All of these risks become cost items in the developer's cost modeling spreadsheet, and/or they increase the cost of borrowing, both of which raise the cost of electricity without benefit to the seller or buyer. Thus, one state strategy to lower electricity cost discussed further in this report is for the state to lower risks to the developer and then to make that lower risk clear to the developers before they place competitive bids.

As will be noted regarding projects in the recent years in Table 1 (discussed in the next section), state-requested project sizes have grown larger, as states have realized that offshore wind power is most cost-effective in large increments. This is consistent with another driver of state OSW policy seen in Northeastern states, where governments compare all of their in-state renewable resources with greenhouse gas reduction targets and find that they cannot reach their targets without including large-scale offshore wind development.

Methods for anticipating the offshore wind power price

The price of electricity from offshore wind power is anticipated here using three methods, each of which has varying strengths and weaknesses. The first method is to examine recent OSW prices in states where utilities are purchasing it. Second is to use a sample of expert estimates

---

[6] Bundling the cost of facilities into a power solicitation may be due to developers realizing that critical manufacturing or ports are not available in the US, so they have to build the facilities in order to build the project. Another dynamic is that In promoting power contracts, developers may promise job creation, the cost of which is then added to the capital cost of the wind project and thus is recovered in ratepayer cost.

to adjust current prices, yielding the price anticipated five years hence. The third method is a bottom-up calculation from component costs, the third being the method used by developers to make power bids.

Having more than one way to estimate the future price of OSW may give more confidence to the result, and can help one understand how the state's approach can lead to lower prices, job creation, or other objectives.

ELECTRICITY PRICES FROM PRIOR US PROJECTS (METHOD 1)
Table 1 shows all offshore wind purchase agreements in the US as of the end of 2021, grouped by state, with power prices adjusted to be consistent with each other.[7]

The "PPA Price" column in Table 1, as noted is levelized real 2021$ price." This column shows that Massachusetts projects have three of the five lowest prices, at $55.70, $66.40 and $75.60/MWh. (The only two slightly lower prices come from states contracting for two projects sequentially, the second of which has lower prices.) In contrast, the most costly projects—South Fork, Skipjack 1 and U.S. Wind 1, are all over $100/MWh.

Table 1. US offshore wind purchase agreements (data sources in Appendix A).

Project	Capacity (MW)	State	Net CF (%)	Year 1 (COD)	Year 1 Price ($/MWh)	Price Escal. Rate (%/year)	PPA or OREC Tenure (years)	PPA Price, Levelized Real 2021$ ($/MWh)
Revolution	400	RI	46.6%	2024	98.43	0	20	$79.3
	304	CT	46.6%	2024	99.5	0	20	$80.2
South Fork	90	NY	46.6%	2023	160	2%	20	$153.8
	40	NY	46.6%	2023	86	2%	20	$82.7
Sunrise Wind	880	NY	44.0%	2024	110.37	0.0%	25	$86.1
Empire Wind	816	NY	43.0%	2024	99.08	2.0%	25	$93.4
Empire Wind 2	1260	NY	43%	2026	107.5	0	25	$83.9
Beacon Wind	1230	NY	49%	2028	118	0	25	$92.0
Atlantic Shores	1509.6	NJ	44%	2028	86.62	2.50%	20	$78.7
Ocean Wind I	1104	NJ	44%	2024	98.1	2%	20	$92.4
Ocean Wind II	1148	NJ	44%	2029	84.03	2%	20	$71.7
Skipjack 1	120	MD	43.3%	2022	$166.0	1.5%	20	$155.7
Skipjack 2	846	MD	44.2%	2026	$86.3	3.0%	20	$85.6
US Wind 1	248	MD	42.1%	2022	$166.0	1.0%	20	$155.0
US Wind 2	808.5	MD	35.5%	2026	$71.5	2.0%	20	$64.7
Vineyard Wind	400	MA	49%	2023	74	2.50%	20	$75.6
	400	MA	49%	2023	65	2.50%	20	$66.4
Mayflower Wind	804	MA	49.0%	2025	70.26	0	20	$55.7

Why are Massachusetts prices lowest? Massachusetts evaluated their bids based primarily (75%) on the price of energy, with 25% on qualitative factors including economic development. The Massachusetts bids further specified larger project sizes of 800 MW early on (by way of two sequential 400 MW projects), the 800 MW size being more cost-effective than smaller

---

[7] The cost column for all is calculated in leveled nominal price, in 2021$. Assumes inflation 2.0%, discount rate of 3.92%. For each project's sources see Appendix B. For a slightly different but published method for standardizing across projects, see Beiter et al (2021),

projects. And wind speeds are a little higher offshore Massachusetts, as indicated by the column for Net Capacity Factor (CF) in Table 1, which further lowers the cost of energy.

If we look at the higher prices in Table 1, those projects were generally contracted earlier, were smaller than the commercially efficient size, and had less robust price bidding competition among developers. The effect can be seen within Maryland, which has two projects under 250 MW priced at $155.00 and $155.70, compared to their two projects over 800 MW at $64.70 and $75.60. Again, the projects over 800 MW are at a dramatically lower cost. Most states required the developer to provide economic benefits such as building factories or other facilities, utilizing local content, and hiring local workers. This was not an error but rather a decision to create more local jobs via added electricity cost rather than state budget, bonds, or other means.

Some of the higher priced projects share only some of these characteristics; for example, the Ocean Wind project is a commercially-efficient size but still has a higher electricity price—perhaps due to New Jersey requiring added job-creating investments.[8] South Fork is expensive even though it did not have job requirements, but it is an early and small project.

More recent projects also have had some technical advantages: increasingly larger MW generators (requiring fewer turbines installed for a project of the same MW size, therefore reducing cost) and a greater rotor area (resulting in higher output per turbine, even at lower wind speeds).[9] The few comparable projects between December 2020 and mid-2021 also show a noticeable drop due to the US enacting the offshore wind Investment Tax Credit (ITC).

In addition to the factors noted above, bid prices also vary because developers differ in their financial status and project cost calculations—including development risk tolerance, access to capital, tradeoff between the risk of losing a bid versus higher profit if won, strategic need to enter the market, supplier relationships, etc. And of course, additional higher-priced bids were submitted in these auctions, but they did not win the price-weighted bid selection, and Table 1 only lists the winning bidder in each auction.

ELECTRICITY PRICE PREDICTED BY SURVEY OF EXPERTS (METHOD 2)

The prior method anticipates future price examining prices from other states' previous contracts. This is by nature backward-looking, and thus is inadequate for an industry whose prices are rapidly dropping due to technology advances and industrial scale-up. Method 2 draws from Wiser et al., who estimate future price of offshore wind electricity based on

---

[8] All offshore wind projects create some local jobs, but electricity costs are raised when states require the developer to make large in-state investments, regardless if they are cost-effective to invest locally. Recent New Jersey bids were evaluated on price as 50% of the ranking, economic and environment benefits 40%, and likelihood of completing the project 10% (NJ BPU, Docket No. QO20080555, 6/30/21). https://www.pjm.com/-/media/planning/services-requests/atlantic-shores-offshore-wind-project-1.ashx

[9] The larger, newly available turbines are the GE Haliade X, at 12 or 13 MW with 220 m rotor diameter; the Siemens-Gamesa 15 MW with 222m rotor; and the announced (but not yet produced) Vestas, at 15 MW with 236 m rotor. The original turbines proposed for the Vineyard Wind bid were 9.5 MW MHI Vestas turbines with 164m rotor; if Vineyard Wind eventually uses a 13 MW turbine, as anticipated in their revised Environmental Impact Statement (EIS), the number of turbines needed would drop from 84 to 62, yet would yield about the same power capacity (84*9.5=798 MW vs. 62*13 = 806 MW). The GE rotor with 13 MW also has a higher ratio of rotor area over generator MW (called the specific area) than the original 9.5 MW Vestas. As the history of the land-based wind industry has shown, larger rotor area can produce competitive electricity prices even in areas of somewhat lower wind speeds. The original Massachusetts bid prices do not reflect these new cost reduction economies.

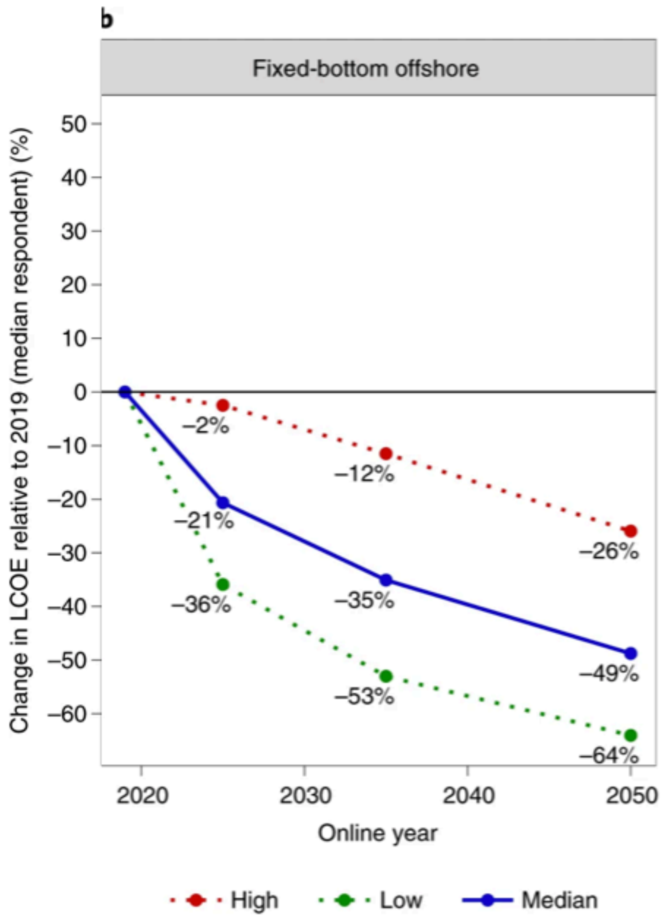

Figure 1. Expert predictions of future levelized cost of electricity from fixed-bottom offshore wind power, relative to the market cost in 2020. Dates are power-on date. (Wiser et al. 2021, Fig 3b).

estimates from a sample of offshore wind experts (2021).[10] They asked experts, "what percentage will the price of offshore wind power increase or decrease in future years, compared to 2020?" The question was asked for 2025, 2035 and 2050. The results are shown in Figure 1, with the solid blue line showing the median experts' prediction. The red (top dotted line) is the 90% high price decile (only 10% gave higher prices) and the green (lowest dotted line) is the 10% low decile. The expert estimates have been validated.[11] We will use the median prediction for 2025 of a 21% further drop in price of OSW electricity, as seen in Figure 1. We chose to reference 2025 as this is the closest year to the modeled power-on date of 2027. Note that Method 2 only provides an adjustment for today's $/MWh prices to anticipate a future price, it does not yield a $/MWh price by itself.

---

[10] Wiser et al.'s sample varies in type of OSW expertise—some polled were more knowledgeable about technical issues, others knew about bidding and prices, the latter of more relevance here.

[11] Wiser et al. conducted the same poll of the same experts in 2015, also asking for expected future prices and report the same distribution points—median, 10% decile and 90% decile. Comparing Wiser et.al. 2015 predictions for 2020 to the actual 2020 contracted prices, actual prices dropped more than the experts' median prediction, and even more than the the lowest 10% expert prediction (Wiser 2021). Although the Wiser et al. low decile estimate in 2015 was the most accurate, we will use the median estimate as our method 2 price adjustment to be conservative, that is, so that we are unlikely to underestimate future price.

CALCULATING ELECTRICITY PRICE FROM COMPONENT COSTS (METHOD 3)
Method 3 for anticipating offshore wind price is to work bottom-up from the cost of individual components to calculate the expected price of electricity. Components include parts such as turbines and transformers and the labor to assemble and install them. Non-physical component costs include early development cost, interest on loans, contract or regulatory risks, and required rate of return. Some of these component costs find their way into public sources but here we draw most from best judgments among our industry advisors, consultants and peer reviewers. All of these component costs are entered into CREST, a National Renewable Energy Laboratory (NREL) supported public-domain tool for calculating the cost of electricity from renewable energy projects.[12] SIOW used this tool for anticipating costs for New York (McClellan et al. 2015) and Massachusetts (Kempton et al. 2016). Calculating energy price from cost components is the method used by developers to inform their bid's electricity price—although they use more complex tools than CREST and have access to proprietary data. Note that since interest rates, rate of return and required profit for investment are included as costs, the result should be the minimum price the developer could bid. In a competitive bidding where developers want the business, one would expect bid prices close to the CREST cost. Access to and use of the CREST cost model and populated spreadsheets is described in Appendix C.

In method 3 we are entering costs and deriving price whereas method 1 observed price (and method 2 adjusts today's prices by expected reduction). The CREST spreadsheet takes costs, plus required profit for investment and risk premiums as input, then predicts a price of energy. That prediction, used here in Method 3 cannot be certain due to imperfect knowledge of input costs, as well as differences in bidding strategy, capabilities of different developers, etc. It may be more accurate in producing changes in price (as we use it in Part II) than the absolute price.

We calculate a projected PPA price of electricity for three example projects, on two hypothetical sites in the BOEM Central Atlantic Planning Area (Table 2 and, later, Figure 4). (BOEM is the Bureau of Ocean Energy Management, within the US Department of Interior). Our Base Project is labelled "A-800," an 800 MW project near to the existing BOEM leases 0498 and 0519 (the leases closest to the Delaware Atlantic coast), which we here call Site A. Table 2 shows price in 2021 dollars to be comparable with adjusted market prices in Table 1.

Table 2. Characteristics of the three modeled projects and calculated costs using Method 3.

Project name	Power capty. (MW)	Distance to POI, AC/DC	Water depth (m)	Coordinates at center of project area (lat, long)	Leveled cost $2021, ($/MWh)
A-800, Base Project	800	70 km, HVAC	32	38.623435, -74.3034655	$71.48
A-1200	1200	70 km, HVAC	32	38.623435, -74.3034655	$67.93
B-1200	1200	120 km, HVDC	40	37.710884, -74.707359	$77.70

The other two example projects in Table 2 are permutations of the Base Project, used to illustrate cost tradeoffs due to distance from Delaware and project size. These locations can be seen on the subsequent map, Figure 4, with the two sites marked "A" and "B," and the point of interconnection marked "I" (the interconnection point is on the map at location 38.58572, -75.23937). The sites and assumptions used to calculate costs are in Table 2, and the reasons for using them are discussed later in more detail.

[12] Cost of Renewable Energy Spreadsheet Tool (CREST), Version 1.4, NREL and Sustainable Energy Advantage, LLC.

Key assumptions and inputs for models in Table 2: The power-on date (COD) is assumed by the cost model to be December 2027. Calculated prices are given in levelized nominal dollars, comparable to Table 1. Turbine size was a blend of scaled 16 MW turbines from two offshore OEMs. Net Energy Production (NEP) is based on regional wind speed and turbines expected to be used for 2027. The capacity factor (CF) at sites A and B are both 44.4%. The developer sells energy, capacity, and RECs to an offtaker, not other products. If no Delaware RECs are associated with offtake, market income from RECs plus capacity is conservatively estimated at $2-3/MWh. There is no separate REC plus capacity revenue listed in the Base Project spreadsheet for the first 20 years of the PPA, because the PPA is assumed to include all revenue sources—energy, capacity and RECs. The “A-800 with DE RECs” case considered Delmarva’s existing RPS obligation as additional revenue to the PPA energy revenue. After the PPA term of 20 years, energy, capacity and REC total revenues are assumed to be a market price of $74.3/MWh (in nominal dollars in year 2047, which is equal to $44.4/MWh in 2021$). The state tax rate is 8.5% and the debt to equity ratio is 56/44. State bid evaluation assumed to weight the price of electricity most heavily among bid priorities. Cost of a project-dedicated O&M port and vessels is included, and cost of generous environmental monitoring throughout the PPA, but no additional facilities are required from the developer. The project qualifies for the full Offshore Wind Investment Tax Credit (ITC), a federal incentive for construction of an offshore wind farm. The price escalation is 2%, and assumed inflation is 2%. The two sites analyzed, A and B, have sand and shell seafloor materials. The A-800 project is the “Base Project” used to compare other projects and to measure how PPA price is affected by various policies or other benefits that the state might want to include in the RFP. The full CREST model used for these price calculations is available to accompany this report, and is described here in Appendix C.

Projected price of offshore wind power

With the above three methods, we project electricity price ranges for an offshore wind power plant under the five conditions shown in Table 3. The Massachusetts contract and the bottom-up calculations assume a bid evaluation that prioritizes lower cost. All price projections are compared in equivalent measures by PPA $/MWh, in 2021 dollars as shown in Table 1.[13]

The first row in Table 3, labelled “Method 1: Massachusetts,” draws that state’s three contracted prices in Table 1, whose evaluation emphasized low price the most, resulting in prices from $55.70 to $75.60. Row 2, labelled “Method 1: Maryland,” uses projects greater than 800 MW. Maryland had economic development costs loaded into the power costs and

[13] We do not include in Table 3 costs for balancing fees or load-following for wind generation, nor benefits of wholesale price reduction due to adding 800 MW more generation in Delaware. Both are complex to estimate because they are highly dependent on the local power system and are beyond the scope of this analysis. Projects calculating these market effects in Massachusetts, New York and New Jersey have found that the added cost due to balancing power is substantially lower than the savings due to wholesale price reduction (see section “Right sizing” (Beiter et al 2020). Therefore, ratepayer impact is lower (a greater savings) than shown in Table 3’s wind power prices.

also has lower wind speeds. Both factors raise the power price above Massachusetts to the range $64.70 - $85.60.[14]

Row 3 of Table 3, “Method 2: Maryland,” shows the Wiser et al. projected price reduction from 2020 to 2025, and applies it to the range of the more pessimistic Maryland prices from Row 2.

Row 4 of Table 3, “Method 3: Delaware,” shows the bottom-up CREST estimate of the 800 MW Base Project, A-800, assuming completion in 2027.

The last row uses Method 3 with the A-800 Base Project but reduces this price by implementing from 0 to all 6 of the “State actions to minimize cost” section in Part II.

Table 3. Market price of offshore wind electricity, projected using three methods.

Price anticipation method & case	Price ($/MWh)
Method 1: Massachusetts contracted wind power prices, where bids were picked primarily for low cost (range of three MA projects from Table 1)	$55.70 - $75.60
Method 1: Maryland contracted wind power price, including ≈800 MW projects, with economic development costs, and lower wind speed (from Table 1)	$64.70 - $85.60
Method 2: Maryland contracted wind power price from Method 1 above, adjusted by Wiser et al.’s projected -21% price drop by 2025	$44 - 68
Method 3: Delaware Base Project A-800 bottom-up calculation, no Delaware RECs	$71.48
Method 3: Delaware Base Project A-800, plus implement 0 to 6 state cost saving measures (see Part II and section “State actions to minimize cost”)	$52.31 - 71.48

Wind price compared with market price and external costs

How can the reader evaluate whether the range of projected wind bids in Table 3 is reasonable to pay? In Table 4 we provide several comparison power prices. The first line is the auction price results for wholesale power purchased by Delmarva Power yearly from 2015-2021 (Liberty Group 2021). (We use Delmarva because it is PUC-regulated and its costs are public information.) As a simple comparison of only market prices, compare the two “Method 1” lines in Table 3 with line 1 in Table 4. The range of Delmarva wholesale power purchase prices is comparable to recent wind power prices. Alternatively, per Method 3, compare Delmarva market prices with the bottom-up calculated wind price in the two “Method 3” rows of Table 3.

The market price of power, the top row in Table 4, is what the typical state utility commission (e.g. a PUC or PSC) uses to compare conventional power alternatives (e.g. coal vs. natural gas

[14] In the later procurement options section, we show that $150MM developer payments, for facility upgrades and local content, increases the cost of energy by $3.40/MWh (Maryland’s total requirement were above this). To approximate the effect of MA versus DE wind speed, one can replace the Massachusetts capacity factor (CF) of 49% into the Delaware Base Project model’s 44.4%, which yields a price reduction of -$7.10. The CFs used here in the CREST model (from Table 1) assume no further technical improvement. It is equally likely that turbines for the Mid-Atlantic improve turbine rotor area to generator MW (the “specific area”); due to the market size of NY, NJ, MD, and VA, higher specific area turbines may be available in time for a 2027 Delaware project, lowering cost below our Base Project by up to $7.10. Higher specific area is a potential price reduction not included in our tabulations.

power). However, there are additional costs to fossil fuel air pollution and CO_2 emissions. The lower three rows of Table 4 give dollar cost for health and/or CO_2 costs.

Table 4. Conventional electricity price, comparison market (2021$ rounded to nearest $).

Source for conventional electric supply cost to compare	Added external costs	Power Cost ($/ MWh)
Market price comparision		
Delmarva power wholesale purchase yearly auctions, price range 2015 - 2021 (Liberty Group, 2021).	0	53 - 82
Market + External cost comparison		
Add health cost of power (Buonocore et al. 2016; EPA 2021b)	$41	94 - 123
Add carbon cost of electricity (White House 2021)	$40	93 - 122
Add both health cost and carbon cost to market price	$81	134 - 163

How can pollution and CO_2 be given specific cost numbers? Buonocore et al. (2016) have modeled the construction of new offshore wind power in New Jersey and Maryland using a detailed model that converts offshore wind speeds to hourly power output, then determines which fossil fuel plants would be shut off or derated to accommodate wind at that hour. It then uses a weather-air dispersion model to conclude which neighborhoods will consequently breathe less fossil pollution, and an epidemiological model for the resulting health benefit. Buonocore et al. (2016) is the most comprehensive state- and project size-specific evaluation published, finding for New Jersey a $41 health savings for each MWh of wind produced.[15] More recently, US EPA similarly analyzed the overall mid-Atlantic region (EPA 2021b), not specifically by state or project, confirming the Buonocore numbers. With a similarly thorough model, EPA found the health benefit value to be from $31 to $69/MWh, with the range reflecting differences within the Mid-Atlantic as well as a range of uncertainty (EPA 2021b). We use the more specific Buonocore $41/MWh here.

Health damage from power plants is very real, as are health savings from adding new renewable generation. These two detailed studies calculate how much those savings are. For every MWh of fossil power displaced by a MWh of wind power, someone—the electricity user or other people in the region, their insurance company, or the government— pays less for the health damage and mortality (collectively, we pay $41/MWh less, or by the EPA estimate, we pay less within a range between $31 and $69/MWh).

The row "Add health cost" of Table 4 shows that if we take the wholesale electricity price and add the $41/MWh health cost, the total cost of existing power for market purchase plus health damage is $94 to $123/MWh.

To measure climate change cost in dollars, there is a Federally-promulgated cost of $56 per metric tonne of CO_2 emitted (White House 2021). This is required to be used in Federal projects to evaluate the financial impact of the project's CO_2 emissions (the state is not required to use it, but can do if it choses). For power generation, the cost of carbon can be converted to cost

[15] Buonocore et al. 2016, from 1,100 MW New Jersey OSW built in 2017, Table 1, Health benefits/MWh = $41.00. One of the health benefits is that the 1,100 MW New Jersey offshore wind generation prevents 13 premature deaths from fossil air emissions. Scaled to the A-800 Delaware plant that would be 9.5 lives per year saved.

per MWh of fossil electricity produced.[16] In the report, we tabulate carbon cost as a way of understanding environmental impacts and costs, including the value of hedging against future carbon costs, not as a policy recommendation.

Table 4's "Carbon cost" row adds the cost of CO_2 emissions from one MWh of displaced fossil power, CO_2 that would not be emitted if that MWh was instead from wind power. Then, the last row adds both health and carbon costs, thus quantifying the market, health, and climate change costs added, a sum economists call the "total social cost." Economic theory would hold that values in the last line of Table 4 , which sums market price with both externalities, is the correct dollar amount to compare to the cost of wind power in Table 3.

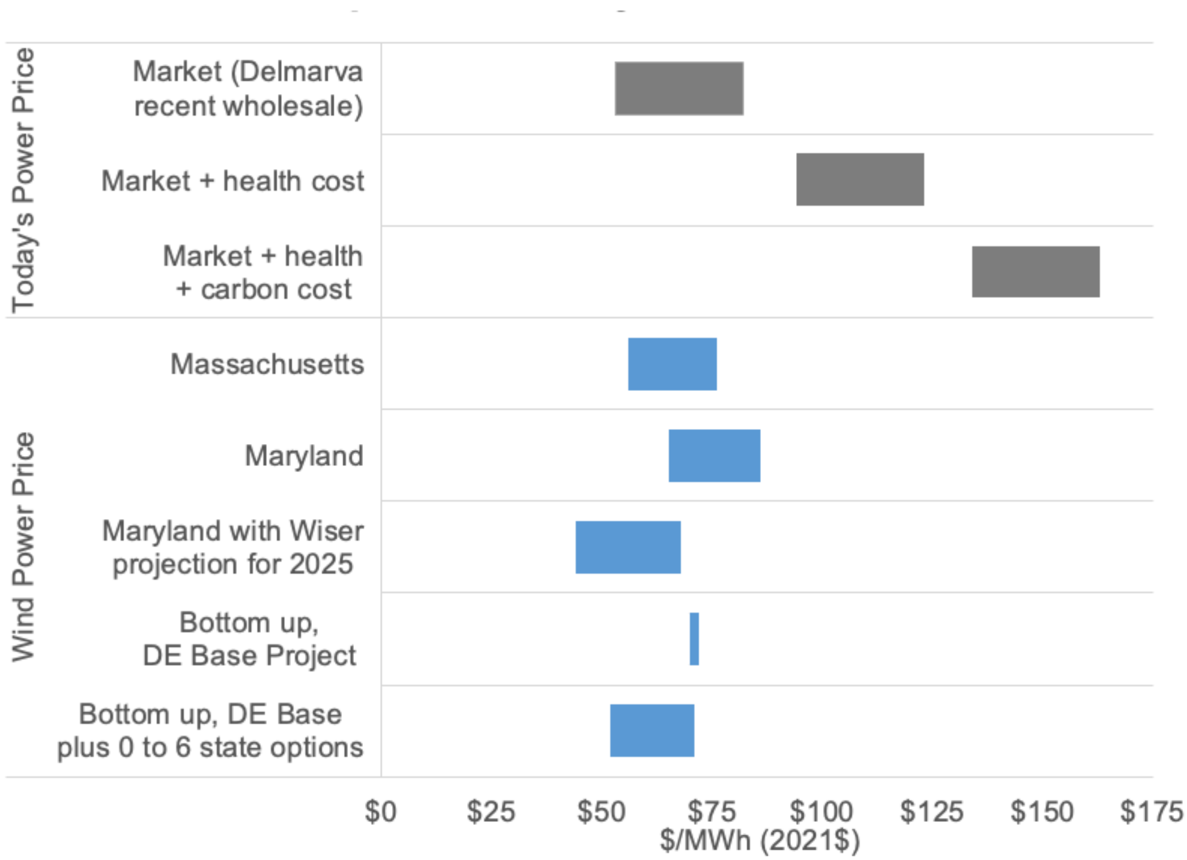

Figure 2. Today's electricity price (top grey bars) compared with wind price (blue). Today's market price with added externalities are included in 2nd and 3rd grey bars and in all blue bars. Bars indicate a range of prices. The six state price reduction options in the last bar are described in Part II.

Manufacturing wind turbines, shipping them to the customer, assembling them in the ocean, and maintaining them over 30 years also creates air pollution and CO_2. Adding all of these lifecycle emissions, Bonou et al. (2017) computed the lifetime CO_2 emissions of offshore wind

---

[16] From White House (2021, Table ES-1), assuming 3% discount rate, 2025 emissions year, the cost of carbon is $56/metric ton. For electric power, US average power generation is 0.709 metric tons of CO_2 per MWh generated (EPA 2021a), thus the US average carbon cost of electricity would be $39.70 per MWh. President Biden has initiated a review of this cost in 2022, it could go up or down after review. Requiring its use in Federal projects is also under judicial challenge, which is not relevant here because we are only using the metric to inform the discussion, not as a policy recommendation.

to be 7.8 g/kWh (grams of CO_2 equivalent per kWh). By the same cost metric used above for fossil fuel power, that would add a carbon cost of $0.44/MWh to the wind prices in Table 3.[17] Since the comparable carbon cost is $40.00/MWh for fossil fuel power, wind is 1/100th of the carbon cost. We didn't complicate the tables by adding carbon and health costs to the wind price; it is so small that it would make no difference in the conclusions. (We do include wind's carbon cost in Figure 2 by simply adding. $.88/MWh to all the wind power costs.)

In summary, if only the market price is considered, the cost of offshore wind power is within the range of Delmarva's recent power purchases, and that is true when using any of the three methods for forecasting market price. If the external costs are added to both wind and conventional power, the cost of offshore wind power is less than half of the cost of our current power. If some or all the six state options for reducing cost of offshore wind power in Part II are implemented, the price of wind would be in the range of $52.31 - 71.48/MWh. These prices are visually compared in Figure 2.

In Part I of this analysis, we have forecasted wind prices for a Delaware solicitation using three methods, and have quantitatively compared current power costs with or without externalities. Each market comparison method finds that expected offshore wind power prices would be about the same as our current electric power. If external costs are considered, offshore wind is much less expensive than our current power. Part II will show how Delaware can carry out a process to procure offshore wind power. Then it will identify additional state actions as options for Delaware to further lower prices as previewed in the last line shown in Table 3, as well as options to create more economic opportunities.

Part II: Options for a Delaware Solicitation

Part II describes how a state can create a solicitation for offshore wind power, drawing on experience from the six states in Table 1 that already have contracts. By comparing the experience of those states, Part II describes different options that Delaware can choose in setting up the request for proposals, the evaluation of bids, and optional related state actions.

How a Power Solicitation is developed

This section gives an illustrative summary of the steps in a power purchase process and the state and private entities that carry out those steps. It also gives a flowchart with the chronological steps and decisions that a state can take and a potential Delaware-specific schedule synchronized to Federal actions. Some steps and suggestions in this section are drawn from are those that have worked elsewhere (a good summary is in Beiter et al 2020b), some are tailored for Delaware, and some are recommendations in order to avoid conflicts or slowdowns seen in other state projects.

Definitions of the parties and documents of a power procurement

The processes and participants in a power solicitation are defined here:

---

[17] Bonou et al. (2016) calculate 7.8 g CO_2-eq./kWh lifetime emissions from a 6 MW offshore wind turbine in Europe, which can also be expressed as a carbon payback of 10 months. (Compare: a 3 MW offshore turbine is 11g CO_2-eq/kWh, and a 3.2 MW land turbine is 5g/kWh; larger turbines create less CO_2 per MWh.) For units equivalent to Table 4, offshore wind carbon emissions are 7.8 g/kWh * 1,000 kWh/MWh * 0.00001 tonne/g = .0078 tonne/MWh. At $56/tonne, the carbon cost of offshore wind is $0.44/MWh. The health cost of emissions is roughly comparable to the carbon cost, as seen in Table 4, so we use $0.88/MWh for the wind external cost of both.

- Bidders: offshore wind developers responding to an RFP. The bidders propose, develop, and build projects to produce and sell electric power. Bidders will submit bids in hopes of being selected to contract with offtakers to sell power from a wind project.
- Qualified bidders: Before accepting bids, the state typically requires qualifications from potential bidders, for example, the technical ability to design and build a project, financial resources to pay for it, site control (holding a lease designated for a wind energy), etc.
- Offtaker: buyer of power. This is typically one or more regulated utilities, but can be municipal electric companies, co-ops, state facilities, local governments, or other large power buyers.
- RFP: request for proposals (RFP). RFPs are usually designed by the state in consultation with offtakers[18] and may be issued either by the state or by the offtaker.
- Proposals or "bids" are submitted to evaluation Agencies in response to the RFP. These offer a specific capacity of generation to sell electric energy with other attributes (e.g. RECs, capacity) at a given price per unit, as well as a description of the bidder's proposed project.
- Agencies: one or more state administrative entities, designated by the procurement legislation or assigned by the Governor, to write the RFP, set qualifications for bidders to submit proposals, evaluate bids, and recommend choice of a winning bid. (In this document, we capitalize Agencies to indicate this specific meaning.)
- PPA: Power purchase agreement, a contract between the developer as seller and the offtaker as buyer.
- COD: Commercial Operation Date, when the last turbine has been tested and all turbines are operational at full power.
- Procurement legislation: If the state decides to proceed, it would have to pass a bill to define the process for procurement, authorize this process, and direct Agencies to carry it out.
- Procurement: Refers to two things: 1) the RFP and evaluation of bids specifically, and 2) generally, to refer to the actions of the state and offtaker throughout the entire process described below.

Steps in the power procurement process

Here we summarize a power procurement process that would enable Delaware to initiate and carry out an offshore wind energy procurement. The flowchart in Figure 3 demonstrates the chronological decisions and actions taken by the legislature, Agencies, and the developer. The flowchart also illustrates conditions under which the process would stop, such as insufficient qualified bidders or insufficient proposals. In Figure 3, the green boxes represent the path toward a completed power contract and red boxes are stopping points in the process. The titles on the left, 'Legislature Considers Offshore Wind Procurement Law,' 'Agencies Develop and Issue RFP,' etc., label the major stages of the process.

As described in the flowchart, the legislature specifies three items that Agencies determine in the solicitation process: the minimum qualifications for bidders, RFP requirements for qualifying bids, and the evaluation criteria to rank bids and choose a winning bid. That enabling procurement legislation guides Agencies through the process.

Suggestions for establishing the procurement requirements and process

Here we provide some suggestions for the overall process that, based on experience of other states, may clarify the tasks of the Agencies or may avoid conflicts. (Specific policy decisions, such as adding the cost of job-creating facilities are separate decisions, and are broken out in a separate section.)

---

[18] Massachusetts also opened their draft RFP for public comment, see https://macleanenergy.com/public-comment-on-draft-rfp/

Figure 3. Flowchart of the procurement process by a state.

The process and deadlines described below are carried out by the state, but we here synchronize the timing with scheduled federal actions and the benefit to ratepayers of Delaware deciding factors early, whether in the bill language or in the Agencies' RFP language. As explained in the next sections, decisions confirmed by the release time of the RFP can shorten the timeline, clarify the process, and reduce risk premiums, thus lowering the cost of electricity to the ratepayer.

The state can improve the process by providing direction on the RFP requirements and on criteria for ranking bids. For example, other states have debated the tradeoff between lower price versus non-price evaluation, such as requirements to build in-state facilities, purchase "local content" (buying from in-state suppliers), or potentially many other criteria including social and equity benefits, a stakeholder engagement plan, and others. Although each criterion will have constituencies, states that have evaluated bids primarily by price have (unsurprisingly) achieved the lowest prices for electricity.[19] Whichever criteria are chosen, an RFP is easier for bidders to respond to effectively if it announces the specific percentage weighting to different criterion and if it itemizes all required components of a qualifying project.

Delaware already has passed a Renewable Portfolio Standard (RPS), amended 2021 and scheduled through 2035. Optionally, the legislature could direct offtakers with RPS requirements to purchase their needed RECs from the Delaware project as part of the OSW procurement, rather than buying RECs from out of state. The legislature or Agencies could maximize the benefit to ratepayers by setting the price at the time of the RFP (or in the procurement bill) on a fixed price schedule rather than a fluctuating future market price. A pre-set price would avoid the problem of the developer overpricing energy due to not knowing the future price of RECs (risk of forecast error). For that reason, having a contracted REC price, even if not covering all MWh of generation nor the whole PPA period, is helpful in reducing the PPA energy price. Thus we recommend that the PPA require that the offtaker buy RECs at Delaware's current percentage schedule (2021 amendments to Del.C. § 354 *et seq*, Title 26) and at the currently-projected cost of RECs (Appendix B). This requirement and clarification lowers the price of wind energy by $1.77/MWh.

Another option is the use of RPS and REC mechanisms in parallel with the price. States like Massachusetts above, as well as Rhode Island and Connecticut, have used a PPA for their utilities to buy offshore wind electricity along with RECs from developers (under conditions set by the state), while others have created a newer mechanism called Offshore wind Renewable Energy Credits (ORECs). For ORECs, the bidding developer sells power at market price, possibly to a Regional Transmission Operator such as PJM. Then, the state or offtaker makes a separate "true up" payment to the developer to supplement the market sale enough to reach the agreed to OREC price. Thus ORECs are tied to a specific wind developer and auction. The OREC payments also obligate the state or offtaker to a separate 20 or more year payment stream. With the price of offshore wind now at or below wholesale energy, at least for many utilities, offshore wind will increasingly be sold by competitive PPA-type mechanisms, without any subsidy.[20] If the state has already passed a RPS requirement (like Delaware), the PPA can purchase energy and RECs as a way of meeting state requirements to increase renewable energy.

For the case of Delaware, we believe that the PPA with offtakers, potentially including purchase of existing RECs, is preferred over the creation of ORECs for several reasons:

1. If low price is a primary bid evaluation criterion, the analysis in this report shows that today's new contract prices will be similar to the current power market price (if the RFP and evaluation are well structured), so an OREC is not needed.
2. As of 2021, Delaware already has an RPS requirement which ramps up to levels that in-state renewables are unlikely to be sufficient to meet. An offshore wind project could use the existing RPS requirement and REC mechanism rather than creating a new mechanism.
3. PPAs with utilities provide the most creditworthy buyers, thus improving developers' project finance terms and lowering the cost of electricity.
4. In a detailed comparison of the PPA and OREC methods along with many sub options, PPAs contracted with utilities were found to be the most common way of purchasing wind

---

[19] There is not really a tradeoff in environmental issues because these projects are regulated by both Federal and state agencies (in Delaware by DNREC) and must meet environmental requirements.

[20] Cost-parity is currently aided by the Federal Offshore Wind Investment Tax Credit (ITC), but eventually the price of offshore wind will likely fall below market competition due to technology and scale cost-reductions without the ITC.

projects (Harris 2015, p.15) and PPAs contracted with utility offtakers resulted in significantly lower ratepayer cost (Harris 2015: 101-102).

5. The PPA makes the actual cost of wind power more transparent to both evaluators and the public. The PPA price is what the offtaker actually pays the generator for electric energy the first year, continuing in subsequent years typically with a fixed price escalator.

The use of a PPA does require careful structuring of the contractual agreement to ensure that PPA purchasing requirements are not imputed as debt on the offtaker's ledger, which would reduce the utility's creditworthiness and potentially require the utility to raise offsetting equity. This can be addressed in the requirements of the RFP and in the contract between the developer and the offtaker.

An example for which imputed debt is more likely would be a generation project (wind or otherwise) whose output is sold to only a single offtaker. Ways to avoid this include: 1) multiple utilities buy the energy; 2) offtaker(s) buy only energy while the generator sells other electric products (such as ancillary services, capacity, and/or RECs) on PJM or other markets; 3) provisions are set in state law to avoid imputed debt, such as those in 26 Del.C. §364, or 26 Del.C. §358, specifying that the "electric companies participating in [an energy] provider project shall collect and disburse funds solely as the agent for the … project and shall have no liability except to comply with the tariff provisions … set forth in subsection (d) of this section;" or 4) the regulated utility could co-develop or co-own the offshore wind project. These specific ways to avoid imputed debt may need to be authorized or directed in the procurement law in order for offtakers to be assured they will avoid imputed debt.

Table 5. Potential procurement schedule for Delaware.

Milestone	**Completed**
General Assembly passes procurement bill	June 2022
BOEM Final lease notice for Central Atlantic "early/mid 2023"	Q1 2023
BOEM lease sale for Central Atlantic "mid-2023"	Q2 2023
Delaware Agencies issue RFP	Q2 2023
Bids due from bidders to evaluators	Q4 2023
Agencies select bid to negotiate contract (developer can start surveys)*	Q4 2023
Contract negotiation complete with offtaker(s) and developer	Q1 2024
Developer submits Construction & Operation Plan (COP) to BOEM	Q4 2024
BOEM approves COP, created Record of Decision (uncertain timing)	Q4 2025†
Developer completes safe harbor investments (to qualify for ITC)	Q4 2025
Developer reaches financial close with investors	Q1 2025†
Construction begins	Q2 2026†
All construction complete; full generation on-line (COD)	Q4 2027†

† Because the COP approval has traditionally taken at least two years, not the one year shown here, all dates designated † could be one year later than shown.

Representative schedule from law to power production

If the State decides to proceed with a procurement, Table 5 gives a plausible schedule of state actions and linked Federal actions. This is based on SIOW's experience in other states, the published schedules of the Commonwealth of Massachusetts,[21] and consultation with experienced parties. Nevertheless, it is an aggressive schedule which would require a concerted effort. A somewhat accelerated schedule is plausible because, by the time Delaware's project would be in permitting, federal regulatory agencies likely will have processed many other projects and, hopefully, will have streamlined their processes. Delaware could also be faster than other state schedules shown in Table 5, if some of the optional policies in the next section are taken by the state. Another option to speed up the schedule would be to accept an earlier round of bids from developers who already hold leases prior to the BOEM Central Atlantic lease sale (not shown on schedule).

The Federal Investment Tax Credit (ITC) deadline is included in Table 5 because meeting that Federal deadline has a very large benefit to ratepayers, but requires several prerequisite state actions. In order for the winning bidder to be willing to spend 5% of the project cost by December 2025,[22] they would require a signed PPA from the state or utility, and ideally would also have both BOEM approval of their Construction and Operations Plan (COP) and financial close with investors. Table 5's 2022-2024 benchmarks define an aggressive schedule mostly controlled by the state, one which would allow making the ITC deadline, and one that is consistent with the BOEM lease sale timing. Failure to meet the ITC date would add to ratepayer cost, as calculated below. Unless extended by Congress, the tax credit drops to zero January 2026.

In this report, when the price impact of a state action can be calculated, it is laid out in the format of the below impact of ITC. First, "➤Calculating impact on power price" explains how the change in price is calculated. Then, the following mini-table shows the input cost change(s), with the resulting plus or minus effect on the price of power.

➤ **Calculating impact on power price** The Base Project cost model assumes that the ITC deadline is met; the calculation below shows the increase in cost if it is not. Not enabling the developer to qualify has the largest impact on cost of any of the state actions we analyzed, and its impact would hurt the ratepayer. It's a $614 million loss of tax credit, resulting in an energy cost increase of $20.42/MWh.[23] Given the potential impact, if the schedule were at risk hopefully all parties would strategize well in advance if the schedule were at risk and speed up or adjust prior steps well before the ITC deadline.

Higher CAPEX due to missed date for ITC	+ $614 million
Effect on power price	+ $20.42/MWh

---

[21] See Massachusetts 83c III timeline at https://macleanenergy.com/83c-iii-timeline/

[22] In December 2020, Congress created a new 30% investment tax credit (ITC) specifically for offshore wind projects that begin construction by the end of December 2025 (IRS 2021). "Begin construction" includes a safe harbor provision, which allows that if the developer expends 5% of project cost by the end 2025, and then shows "continuous efforts to advance towards completion" each year after, the full 30% ITC is available. The Build Back Better bill, if this providion of it should be passed into law, would extend this deadline another 5 years at the same 30% level.

[23] To calculate the ratepayer cost, one can used the Base Project spreadsheet, whose use is explained in Appendix B. The change would be made under Federal Incentives, cell Q22.

RFP requirements and bid evaluation

Based on lessons from other states that have held solicitations, we list below the solicitation characteristics that we have identified as most favorable to the the state or ratepayer, which in some cases are also beneficial to the offtaker or developer. Most are suggestions because most we consider simply good practice which we do not expect to be controversial. A few involve tradeoffs: for example, a lower price of electricity may be prioritized over more job creation or vice versa. Below is a checklist of potentially favorable characteristics, not in any specific order, to be considered for a state procurement bill and overall plan. Whether each checklist item would be implemented will be determined by the state.

1. The procurement and RFP should ensure competition among bids. For example, if there are fewer than two qualified bidders by the deadline to submit qualifications, the RFP should be delayed until there are at least two. The lack of competition for a given solicitation would create poor market conditions and increase the likelihood of high electricity price bids.
2. The electricity cost escalation rate should be specified in the RFP instead of being left open for each bidder to decide. Having the same escalation rate across bids makes it easier for both evaluators and the public to compare bid prices. Industry practice is beginning to settle on a 2% escalator (see Table 1, column "Price escalation rate"), a rate which is close to the forecast of US long-term inflation through 2030 of 2.3% (USDA 2021, Table 2). We recommend that a 2% escalator be required in bid prices and that documents headline the first-year PPA price, expressed in the nominal dollars of the bid evaluation year.
3. The RFP should request bids for 800 MW of capacity. Or, the legislature could optionally allow larger bids (up to 1200 MW) if the bidder addresses the issues listed in the section "Right sizing the project." A minimum of 800 MW is recommended because a project smaller than 800 MW would significantly increase ratepayer cost, whereas a project as large as 1200 MW will require resolving the questions in the subsequent "Right sizing" section. (All sizes should allow some tolerance, say ±100 MW, due to site engineering not being firm at date of bid proposal.)
4. The RFP should state that a PPA will be used, and that it will bundle capacity and energy.
5. The draft of the PPA should be written by the Agencies, with consultation. After the winning bid is selected, each offtaker utility can work out modifications within the Agencies' framework for utility-specific circumstances. Each final developer-utility PPA agreement would be approved by the PSC or collectively by the Agencies.
6. If the state chooses to use RECs for this project, the Agencies should specify in the RFP how a proposed project would supply RECs and at what pre-determined price for reasons noted above. One possible REC payment schedule is given in Appendix B, based on existing Delaware law (26 Del.C. § 351 – § 364), to set the quantity of RECs required.[24] (There is no need to pass a law with more RECs, to create ORECs, nor any other new state subsidy mechanism—see "Suggestions for establishing the procurement…" section above.)
7. Dates for the RFP and bid schedule should allow bidders to qualify for the Offshore Wind Investment Tax Credit available through 2025, as noted in the above section "Representative schedule.…"
8. If a common transmission corridor is contemplated, the RFP must give conditions under which the developer can expect transmission to be available prior to their project completion.

[24] The Delaware state RPS requirements were recently amended by the 2021 General Assembly, changing § 354 *et seq*, Title 26 of Delaware code. The specific requirements and schedule are in the full law, VOLUME 83, CHAPTER 3, 151st GENERAL ASSEMBLY (FORMERLY SENATE BILL NO. 33), Accessed at: https://legis.delaware.gov/BillDetail?legislationId=48278

9. The state should set priorities for bid evaluation. To meet state priorities, it is essential for the RFP state bid ranking criteria explicitly, and give a percentage or weighting for each criterion. Other states have used evaluation factors including: price of electricity, inclusion of job-creating facilities, project distance from Delaware, or other social benefits. We are not advocating which of these should or should not be included in evaluating bids; we recommend only that the state recognize that: each added criterion increases power price, that they must be decided and specified in the RFP, weightings are needed for each criterion, and that bids are evaluated accordingly.
10. If job creation facilities are to be required, funding should be explicit in the RFP, either stating the type of facility for the developer to fund or requiring a payment though the state agencies to meet designated goals. The dollar amounts required should be specified in the RFP so that it is a known, specific quantity added to the bid. (Options for job creation are described in the section "State options to increase employment.")
11. Specify in the procurement law whether the Agencies should allow a shared transmission corridor; if there is shared equipment, that would probably require a separate binding process (see below). The bidding process or timing is probably best left to the Agencies.

The following items may may involve tradeoffs, but may also be considered:

12. Include a provision that if the cost of the project is substantially lower than bid, ⅔ of the savings go to lowering energy cost for ratepayers and ⅓ go to developer profit. No corresponding allowance is made for cost overruns. Note that prior US projects have achieved lower cost after RFP bid price was set most frequently because larger or more efficient turbines are available after calculating their bid price, and this change in cost is easily audited.
13. In the past, the Delaware PSC has interpreted its mandate to favor the lowest cost of power as market price, regardless of non-market cost considerations. If the legislature is encouraging offshore wind in part to create new industry, mitigate climate change and/or reduce health damage, then a procurement law could explicitly direct the PSC to use data on one or more these aspects when calculating which alternatives have the lowest cost. This would prevent conflicting directives with the PSC.
14. To make item 13 clear in evaluation and to facilitate public debate, the RFP could request that bidders report dollar per-MWh calculations of climate and health benefits for their specific bid, using data sources like those in Table 4.
15. Consider legislation requiring or incentivizing power purchase by all Delaware utilities proportional to load. This is anticipated in Title 26, § 363 "(a) Any municipal electric company and any rural electric cooperative may elect to exempt itself from the requirements of this subchapter, if it develops and implements a comparable program to the renewable energy portfolio standards for its ratepayers beginning in 2022."

State actions to minimize cost

This section describes potential state actions intended to reduce electricity price. For current US offshore wind project development, we have found that states inadvertently add risk and potential delay, requiring developers to add in contingency costs when they bid to sell electricity. In this section we describe potential state actions to reduce risk and delay. On the estimated effect on price, note that the cost of some measures are precise whereas others require judgments about project costs, for example, the savings of a schedule speedup, or how much a developer would be willing to reduce their risk premium set-aside for more business. Although the judgements we used here are from experienced professionals who have been responsible for such calculations, they should be treated as useful approximate projections, not definitive, exact predictions. Each of the state options following conclude with a calculation of the cost impact on the price of electricity. We calculate price reductions or increases as adjustments from the Base Project price, $71.48/MWh from Part I. For example, if we conclude that X state action would cause a change of -$1/MWh in wind power price, that would mean that the resulting wind price would be $70.48/MWh.

State urges BOEM to create more leases near Delaware

In the US, developers first obtain leases from BOEM through a competitive leasing auction. The developers must pay hundreds of millions of dollars (as of bids in the Feb 2022 NY Bight auction), in order to gain exclusive right to submit a construction and operations plan (COP) to develop offshore wind within that lease area.

The BOEM lease does not provide any assurance of revenue, and any revenue would be at least 4 years later (see schedule in Table 5). Later, when a state issues an RFP, states allow only qualified developers already holding leases to bid (the secured lease is also called "site control".)

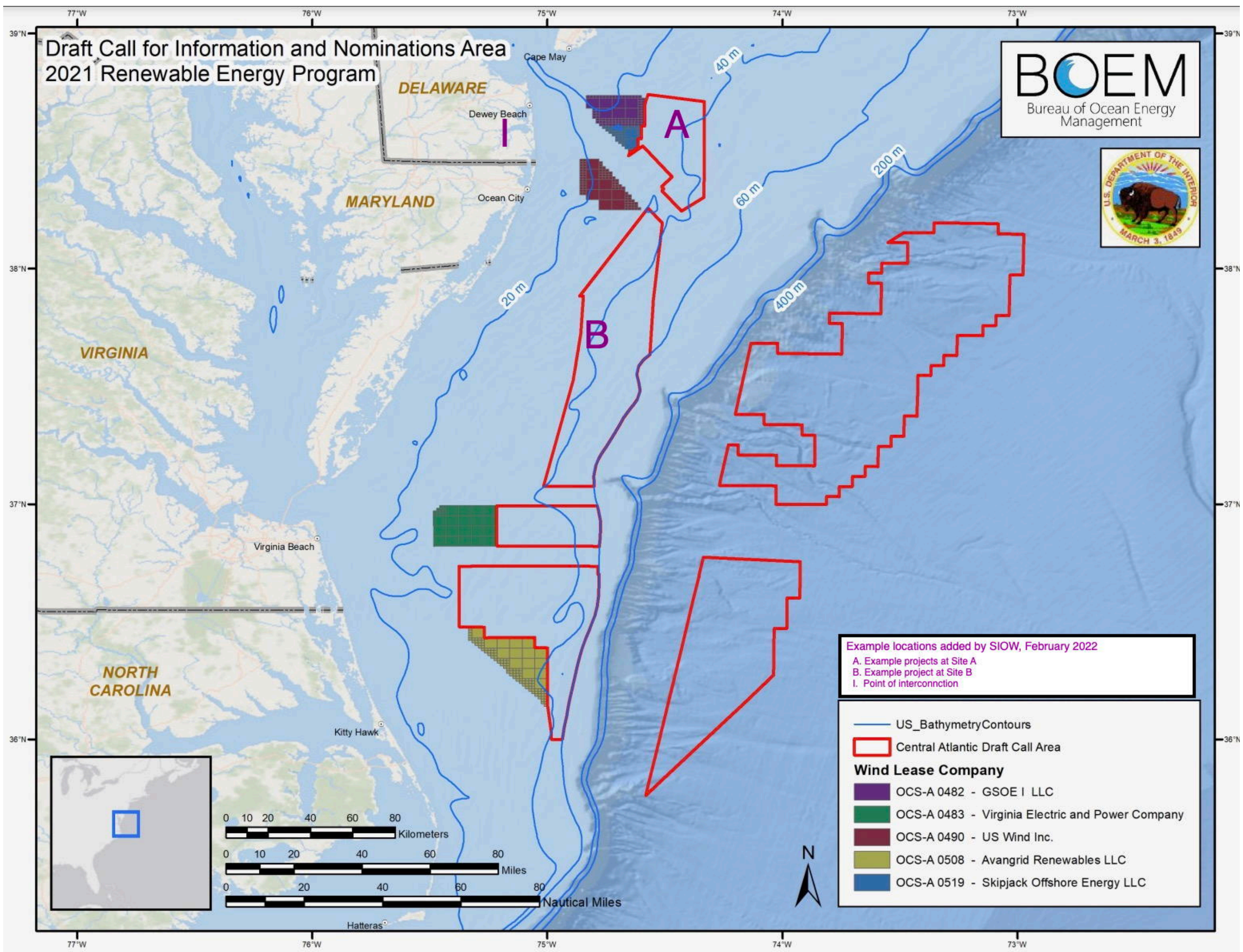

Figure 4. BOEM announced Central Atlantic Call Areas (red outline), within which WEAs will be nominated. Existing leases are shown as filled-in colors. SIOW has added "A" and "B" as example future wind power site locations, used in the bottom-up price calculations, and "I" as a possible point of interconnection.

In February 2022, BOEM designated the six “Draft Call Areas” shown in red outlines in Figure 4. BOEM will release the final call areas for public comment and based on that, narrow to Wind Energy Areas (WEAs). The WEAs will then be subject to a limited environmental analysis for leasing, and some portion of them will be proposed for leasing in the Proposed Sale Notice. After another round of public comment, BOEM will release a Final Sale Notice setting forth the lease areas that will be auctioned to the highest bidder(s)

The new Draft Call Areas map suggests potential expansion of the number of WEAs near Delaware could soon include locations ideal for Delaware power projects.[25] This is important for Delaware because more leases proximal to Delaware enable more potential bidders in response to a Delaware RFP, thus increasing odds of the state getting better power bids. More nearby leases also increase the likelihood for establishing some onshore support facilities in Delaware. For example, O&M ports, which have very high total job-years, are only practical in locations near the project being maintained. Due to these benefits, the state may want to advocate to BOEM[26] for more nearby WEAs. The state action of submitting comments to BOEM requires no new personnel and has no budget impact.

➤ **Calculating impact on power price** As noted previously, for several state actions, we will calculate the expected change in the cost of energy. When a specific dollar cost is known, we can estimate the impact on price with reasonable accuracy. In cases when judgment is needed, as for commenting to BOEM, price impacts are informed approximation to guide tradeoffs. If BOEM issues more leases, we calculate the reduced cost of power based on an experienced developer’s judgment that a bidder facing more competition would plausibly reduce their Return on Equity (ROE) by 1% to improve chances of winning the PPA bid.[27]

State cost of requesting more WEAs	$0
Effect on power price	-$3.00/MWh

State defines rules for siting the transmission cable landing

One of the largest risks that a developer faces in building an OSW project is obtaining permission and permits for the power cable to pass from the ocean onto shore and to a point of interconnection.

In most US states, any increases in offshore wind energy prices are borne by ratepayers, yet the cable landing route must be approved by local authorities. Past examples have shown that

[25] Figure 4 shows a notch taken out of the western side of the planning area off of Delaware, compared to the areas off Maryland and Virginia, which extend westward to near the continental shelf break (transition from light blue to darker blue). The “missing” rectangle west of Delaware matches the Mid-Atlantic Scallop Rotational Area, in which scallop take is prohibited during part of the year (USC Title 50, Chapter VI, Part 648 Subpart D § 648.60). The planning areas also include deep water (1 to 2 km) beyond the shelf break that could be used for floating offshore wind. Floating wind is currently more expensive for electricity generation, more so in the location shown due to the long transmission to shore.

[26] BOEM’s Central Atlantic Intergovernmental Renewable Energy Task Force meetings on the Draft Call Areas and creation of WEAs continue through Fall of 2022. Delaware is an official participant in the Task Force. WEAs are scheduled to be identified Q3 2022, final sale notice early/mid 2023, and lease sale Mid-2023.

[27] Another benefit of more WEAs in the planning area close to Delaware is reduced cost of transmission. This can be seen in the difference between model projects A-1200 and B-1200; we do not separately calculate this cost savings; the cost reduction calculated more WEAs only reflects increased completion among bidders.

public concerns raised in hearings about power cables may be greatly exaggerated (such as concern about electromagnetic fields, MacGregor, 1994), yet can delay a project. These setbacks have led to significantly increased cost and uncertainty.[28]

Some states have addressed the balance between local authorities and the impact of an uncertain process on statewide ratepayers by shifting unilateral power to the state. New Jersey's recent S-3926/A-5894 exhibits one solution; the legislation cedes full authority to the NJ BPU in favor of project efficiency.[29] Rather than the state superseding, we suggest the state could create a process that requires engaging local communities, consideration of local concerns, and pre-defined compensation for the affected local community. At the conclusion, a decision-maker with statewide responsibility would retain ultimate decision authority after weighing both local and statewide interests.

To model the effect of a well-defined process on reducing energy cost, we suggest one concrete example for illustration. A state procurement law could require that the developer identify at least two workable cable landing locations then require consultation among the developer, local communities, and two appointed DNREC experts, one with extensive knowledge of power line impacts and the any other on local concerns. After consultation and a required public hearing for each potential landing location (and possibly after modification of plans based on public input), DNREC would make a timely decision on which route to pursue, with the directive to minimally impact local communities and the environment at reasonable transmission cost. A pre-specified compensation could be set in a procurement bill or in the RFP; our example financial model includes a set cost for which the developer pays the impacted local governments. In this example, local government would receive $3M for passage of the buried cable from the ocean up to a substation. If additional overhead length is required outside the initial jurisdiction, an additional $1M would be provided to affected communities per 5 miles above ground.[30]

The specific process and compensation amounts modeled here provide only one illustrative example; our recommendation is only that generally, the procurement law should define a process and compensation amounts, and authorize an objective state entity to make a final decision. This will reduce delay, avoidance of decisions, and inflated compensation payments, and will lower the risk to project completion, saving significant ratepayer costs statewide.

---

[28] Examples of costly, delaying cable landing debates in local communities include South Fork on Long Island and Skipjack at Delaware Seashore.

[29] New Jersey addressed this issue in NJ S-3926/A-5894, signed into law July 2021 by Gov. Murphy. This New Jersey law, the Offshore Wind Economic Development Act (amended) gives any BPU-approved wind project the authority to "place, replace, construct, reconstruct, install, reinstall, add to, extend, use, operate, inspect, and maintain wires, conduits, lines, and associated infrastructure, whether underground or overhead or within, under, or upon the public streets, thoroughfares, rights-of-way, or any other public property of any municipality, county, or other instrumentality of the State", regardless of existing state or local laws. The new law further dictates that local authority cannot impose fees on the developer or prevent the developer from running transmission lines across a board-approved route. NJ S 3926 could be criticized as suppressing local decision-making but it does indicate the degree of concern about local decisions overriding statewide initiatives or raising costs for all ratepayers. The Maryland Offshore Wind Energy Act of 2013 similarly moved cable landfall review and approval to the Maryland Public Service Commission.

[30] Consider the following as an illustration of how municipal compensation would be determined. From Bethany substation to Indian River switchgear is about 10 miles; using the example compensation amounts, the landfall community would receive $3M to reach a substation, and Sussex County would receive $2M for 10 miles of overhead transmission.

It may be possible for the state or other non-commercial entities to facilitate other stakeholder processes, not only cable landings. Stakeholder processes have traditionally been left to the developer, but we note that supplementing developer outreach with knowledgable but non-interested parties could better represent the public interest, and may be more credible to some constituencies. This may additionally be helpful toward a more rational and time-delimited process. However, we do not offer a design for general stakeholder enhancement as that is outside the scope of this document. Also, we cannot carry out the analysis of price reduction caused by lower risk and delay this range of decisions, as we lack a method for assuring such process improvements prior to the PPA, thus it cannot lower the bid price. Thus, improvement in only the one specific process, cable landing decision-making, is price-estimated here.

➤ **Calculating impact on power price** Below we calculate the potential savings from a state-defined transmission landing decision process, as opposed to the current, diffusely organized approach. Financial compensations to local communities, as suggested above, are already in the Base Project model cost. Therefore, compensation to communities in this example has zero additional cost above what a developer would assume. Based on the judgement of an experienced project developer, a defined cable landing process would reduce construction risk by 0.5%, plus shorten the project timeline by 6 to 18 months.

State cost	$0
Added developer cost	$0
Effect on power price	- $3.40/MWh

State coordinates electric transmission access with Maryland projects

Approved Maryland projects that plan to inject power into the Delmarva Peninsula (Skipjack and US Wind, as listed in Table 1) now total 2,022.5 MW and propose points of interconnection in Delaware such as Delmarva Power's Indian River Substation. If Delaware proceeds with an 800 MW solicitation and connects the project to a substation in Southern Delaware, new wind power connected on the peninsula would total 2,822.5 MW. Developers are planning these as separate transmission corridors. Rather, if the three projects were designed to connect to shore as a single corridor it would create less construction disruption to residents and the environment. As a further consolidation, if it were a single export cable set, it would be designed differently, and would be more cost-effective. As one of several example designs of a shared cable, this nearly 3,000 MW total capacity from three projects could feed AC electricity into a single offshore HVDC converter station, run a single DC line undersea, then continue over land to the existing Indian River substation. There are several uncertainties in a shared design, especially given that planning on those projects is already underway. Other combined transmission designs are possible, such as combining with only one of the Maryland projects by enlarging their planned AC connection.

As a grid cost benchmark, PJM carried out a power flow study of network upgrades needed to add more offshore wind throughout its East coast area. For Delaware and Maryland, they found that absorbing an added 1,200 MW at Indian River would require $53 million in transmission grid upgrades (Bernstein and Kern 2021); "grid upgrades" are to carry power from the Indian River interconnection to large loads, distinct from the cable from the ocean wind projects to Indian River. To connect the now-approved Maryland projects (total 2022 MW), the PJM study must be updated and the proposed transmission upgrade entered in the PJM queue (regardless of whether or not Delaware and Maryland coordinate).

If Delaware proceeds with a power procurement, the state may want to collaborate with Maryland on a “multi-state agreement” for transmission.[31] If they do, the states could request that the two Maryland developers—and eventually the winning Delaware bidder—plan for a combined power connection, probably to Indian River substation. If the state takes this shared transmission approach, the RFP would presumably be structured so that: transmission is a separate component for bidding, transmission bidding is prior to a Delaware wind project bid; and the transmission must have a binding completion date before the the wind projects’ CODs[32]. If some of this can be worked out before bids are due for a Delaware RFP, that would clarify the transmission cost components for bidding Delaware’s project. If, per the above example, the three lines are combined, cost would be reduced over the default of running three cables, three sets of transformers, and three points of interconnection, savings calculated below. Cost of grid upgrades (from interconnection to load centers) would similarly be split, but we do not calculate added cost nor savings for grid upgrades, only for combining the cables from the ocean to Indian River.

➤ **Calculating impact on power price**   To calculate cost savings, we estimate the cost of a single line combined for three projects, and allocate that cost according to each project’s use, versus each project running its own cable. (As is standard for renewable energy CAPEX, the metric is $/kW.) This cost savings estimate does not include any projected transmission landing savings from the prior section, “State defines rules for siting…”.

CAPEX change for one ~3GW DC vs. three 1GW AC	- 86 $/KW
Effect on power price	- $2.30/MWh

DNREC reviews and provides early guidance on regulatory processes

Before the RFP is issued, DNREC should complete an internal review of how an offshore wind developer would apply to install a renewable transmission cable that extends from an offshore wind project, through state waters to a substation on land. Although the law and regulatory mechanisms are in place for cable line placement in state waters and land, some of the paperwork, including application instructions and forms, could be updated to increase clarity for permitting a new technology like offshore renewable energy.[33]

[31] This is an agreement with two or more PJM states that allows cost-sharing of transmission and may make the project more economically advantageous. This should be set up by the state of Delaware and developers, so as to take advantage of recent FERC rules and potential federal transmission funding.

[32] In the past, developers have shied away from shared transmission for fear that it would not be connected when the turbines start up, causing the developers to lose substantial revenue.

[33] To give a few illustrative examples, within the Subaqueous Lands Act (SLA), an Appendix E “Utility Crossings” states that an SLA permit application would be required. However, that form does not specifically refer to cable landings from offshore sources. One question in the application states that the permit does not apply to subsurface power cables; specific questions about cables are lacking (e.g. are they AC or DC, which have different electromagnetic fields). The Beach Preservation Act (BPA) similarly says it applies when there is movement of “substantial” beach materials, but without guidance or examples as to what is considered to be substantial. The Delaware Coastal Zone Act does not appear to regulate cable transit from coastal waters to land nor new switchgear to receive power, as those are not considered "heavy industry” by the CZA. But this is not explicitly stated in guidance to applicants. Clarifications like these on SLA and BPA forms, or in some cases added offshore-wind specific direction or additional questions, could be fixed or added in the application documents as part of DNREC’s internal review process.

As a second step after DNREC's review of the application processes and after making clarifications to instructions and forms, we recommend preparing instructions for offshore wind developers on the process, possibly delivered as a workshop prepared by regulatory staff in conjunction with DNREC's Business Ombudsman and/or via written guidance. This instruction could state that statutes in the Subaqueous Lands Act (SLA) and BPA (and Delaware's CZMA consistency, discussed below) apply to cables from renewable energy facilities, then give some specific guidance.[34] These instructional materials would be beneficial because if bidders better understand the risks of delay due to the state permitting process and understand how to avoid risks, their bids in response to the RFP will reflect that lower perceived risk.

Under the Federal Coastal Zone Management Act (CZMA), the Delaware Coastal Management Program (DCMP) has federal consistency review authority for federal actions that may affect Delaware's coastal resources and uses. Relevant federal actions include federal licensing and permitting, such as that required for an offshore wind project. Unlike most other states, DCMP's review authority for renewable energy projects extends to its NOAA-approved geographic location description (GLD) which encompasses federal waters 3-24 nm off the coasts of Delaware, and Maryland and part of that off New Jersey. Per this review authority, the DCMP would review plans in Federal waters, including turbines, foundations, cables, and offshore transformers. Delaware's 24 nm extent includes all of the already-leased Delaware wind energy area and, within the top two northernmost Central Atlantic Draft Call Areas, a strip along the western edge of them. Thus, for projects in the center or eastern edge of the new call area, only the export cable would be DCMP-reviewed.

Per this extended review authority, the DCMP would review the developer's draft COP and Federal consistency certification, which contain necessary data and information (NDI) required for the review. The developer prepares these documents, then BOEM forwards them to the DCMP upon the Notice of Intent (NOI) of the developer to prepare an Environmental Impact Statement (EIS) under the National Environmental Policy Act (NEPA). Because BOEM's NEPA documents are not considered NDI for the federal consistency review process, a state and developer may enter voluntary stay agreements of the state's federal consistency certification. A stay agreement provides the state with time to review BOEM's NEPA documents and to engage in additional discussions with the developer to help inform its federal consistency review process. Developers may perceive this stay period as adding risk and delay to the federal NEPA review process because a state's federal consistency concurrence is required to issue the Federal EIS and Record of Decision (ROD). The need for a stay agreement could be avoided if NEPA documents were considered NDI as part of the federal consistency review process. However, such a change is out of state jurisdiction and must happen at the federal level between BOEM and NOAA. We would recommend that DNREC make or renew this request of both Federal agencies to consider NEPA documents to be NDI, but proceed without counting on success of this request.

The general approach is for these DNREC offices to review instructions and forms, taking the perspective of new applicants for offshore wind projects and associated transmission, and revise existing materials to provide clear guidance for this new ocean use. Then, provide instructional and/or workshop guidance to potential bidders early in the RFP process, including briefing the Regulatory Advisory Service about different needs for these new ocean uses, so

---

[34] For example, instructional material could state explicitly that a CZA permit is not needed for export cable landing or power transfer on land, and identify support structures that might require a CZA permit (if any). Instruction could review typical examples of time required to reach approval, provide suggestions for developers how they can minimize delay, and give examples or a range of lease rates and fees. For example, would a lease rate be lower if a developer employs methods with less disturbance (e.g. directional drilling instead of trenching)? These guidelines would allow developers to use realistic (even if not precise) costs, timing, and delay risk assessment for their price calculation when preparing their bids.

that bidders understand all the processes and how to navigate them, with certainty as to pathway and without excessive delay, thus increasing confidence while preparing a bid, and reducing their need to build risk and unexpected delay into their expected price of power.

➤ **Calculating impact on power price** The analysis of these measures is modeled as a reduced risk of development delay. To estimate its effect on cost, it is modeled as the development timeline being shortened by 6 months.

Cost to state for review and prepare instruction	$0
Effect on power price	- $3.40/MWh

Install meteorological buoy prior to RFP

The wind speed at the site of a project is essential to power production and to the design and the economics of the project. If the actual wind speed at the wind project site is lower than the developer expects, the energy generated may be less, leading to a higher electric price. If the true wind speed is faster or has stronger gusts than expected, the turbine design may not be strong enough, leading to higher maintenance costs. It is in the interest of the state and ratepayers to have the best wind data available to developers when they are preparing bids for the state's RFP. This requires "bankable" wind data—at hub height, calibrated, and ideally two years—enough to accurately predict revenue and thus to qualify for a loan.

However, developers often cannot obtain permits to install wind instruments in time for an RFP bid. This will be true for new leases within the Central Atlantic Planning Area (see schedule in Table 5).[35] To collect metocean data (wind and sea conditions), an energy producer has to submit a Site Assessment Plan (SAP) under 30 CFR 585 for BOEM approval; this can take up to a year and a great deal of staff time early in the development process. After the buoy is installed, it requires two more years to collect fully "bankable" data. However, a non-energy producer, for example a state government (or their contractor or partner), can apply to place an identical temporary met buoy at the same location, under Section 10 of the Rivers and Harbors act—and receive an approval from the Army Corps of Engineers within two months.

A solution to the lack of met data, and delay in obtaining it, was adopted by New York (at SIOW's recommendation). That is, New York State has put meteorological buoys in areas likely to be bid on by developers, before the lease auction or RFP. They hope that their met buoys will contribute to more realistic bid prices in their next rounds of RFPs. If a probable location for a Delaware-adjacent lease area can be projected, expenditures for a contemporary LIDAR[36] and wind-speed measurements could repay itself in Delaware ratepayer savings.

In what location would a meteorological buoy be optimally placed? Responses to a Delaware RFP could come from existing lease areas held by developers (off Southern New Jersey and what little is left open of the current Delaware leased area, both of which have nearby wind measurements), or bids could come from the new Call Area off of Delaware (Figure 4), which

---

[35] Wind data from nearby, even if not on the exact site, can be used to improve site bids. If one developer did have such data pre-RFP, they would guard it closely to gain an advantage in bidding (whereas it's in the state's interest for all bidders to have good data).

[36] LIDAR buoys for wind measurement float on the ocean's surface, requiring only an anchor cable to keep in place, and use lasers to measure wind speed over 100m above the surface, to predict how much energy a wind turbine in that location would generate.

has no on-site met measurements, nor are there any nearby.[37] A new met buoy in the new Call Area directly East of Delaware's Atlantic coast would complete coverage of likely bid areas.

PNNL has loaner buoys for public entities. The state would be responsible to commission, deploy, monitor for two years, and analyze wind data, then recover the buoy and decommission it, total cost $1.5M.[38] The State would request USACE approval for buoy placement and data collection—thus, if the process is initiated soon after a state decision to proceed, met data could be available a year or more sooner than than a developer could have it. A leaseholder can carry out geophysical surveys based on a survey plan submitted to BOEM 90 days before start of geophysical surveys (no SAP required). That geophysical data is required to be included by the developer upon submission of the COP. It appears that a state met buoy may allow the developer to streamline or even skip the SAP. And, BOEM is reportedly drafting a modification to the regulations that would eliminate the need for submitting a Site Assessment Plan for metocean buoy deployment. So, this may be clarified in the near future, but in either case there is a big payoff for the state to proceed with a measurement campaign very soon after the the state decides whether to proceed with a wind procurement.

➤ **Calculating impact on power price** We predict two savings from 1-2 years of "bankable" wind data before the deadline for the PPA bid. In estimating the change in cost of energy, the reduced risk of knowing the wind speed is modeled as willingness to take a 0.5% lower ROE. The second potential savings is the shortened or eliminated SAP phase, which we model (with less certainty) as a one year shorter development phase, lowering development cost by 20%. Below we compare the cost of the buoy against the savings in electricity price. Unlike other cost estimates, this cost could not be borne by the developer, who (based on current regulations) would not qualify for the streamlined permitting and faster schedule.

Cost to state for met buoy	$1.5M
Cost to developer for met buoy	$0
Price change due to data before SAP	- $1.10/MWh
Price change due to wind data lowering risk	- $2.10/MWh

Right-sizing the project

In the analysis of other states' projects listed in Table 1, we observed that projects of 800 MW or larger lead to a significantly lower cost of electricity than smaller projects. Accordingly, our Base Project is modeled for 800 MW. By the time that a Delaware project's turbines would be ordered, at the end of 2025, our industry advisors report that 15 MW or larger turbines will be standard, and projects of 1200 MW will likely be a more cost-optimum size than today's 800 MW. What are the overall advantages and disadvantages for Delaware of a project larger than 800 MW?

In such comparisons, two related electrical units are used—capacity or load in MW, and electric energy in MWh. To make an easier comparison, we will express everything in MW. Electricity sales and RPS requirements are conventionally in MWh/year. Since there are 8760

---

[37] See the National Buoy Data Center, https://www.ndbc.noaa.gov

[38] Personal communication, Alicia M. Mahon, Ph.D., PMP, Wind Energy Program Manager, Coastal Sciences Division, Pacific Northwest National Laboratory. Email of 16 Jan 2022.

hours per year (365*24), the average MW of power over a year is MWh/8760h = MW_a. For example, all of Delaware's power sales in 2020 were 11,129,051 MWh.[39] That is equivalent to 11,129,051/8760 = 1,270 MW_a. The "average" means that some hours might be higher and others lower, but on average over the year, the entire state of Delaware used 1,270 MW_a of electricity.

On the wind production side, today's offshore wind turbines in Delaware's offshore area, per Table 1, produce 44% on average. Like fluctuating load, wind production fluctuates and is lower some hours and higher others, but on average over a year an 800MW project will produce 352 MW_a (800 MW * 44%). A 1200 MW project will produce 528 MW_a. With this conversion to equivalent units, we have the same units to compare Delaware electric load, Delaware RPS requirements, and production of an 800 MW or a 1200 MW wind project.

On the RPS side, some sales (mostly industrial) are exempted from the RPS requirement. RPS is calculated as a percentage of what is called "non-exempted sales"; here we use the more descriptive label "load subject to RPS". Per Del.C. §354 Title 25 (Amend. 2021), the requirement for 2027 is 26% of load subject to RPS, and by 2035, 40%. The 2020 load subject to RPS of all Delaware utilities is 1064 MW_a (in subsequent Table 7). Per Table 6, which considers all Delaware utilities together, the 800 MW project would provide 33% of load subject to RPS (column 4), therefore the 800 MW project meets the 2027 goal statewide by itself, but not the 2035 goal. The 1200 MW project, producing 528 MW_a, would be 50% of load subject to RPS, exceeding both the 2027 and 2035 RPS. (Table 6 simplifies by showing neither the clean generation contribution from solar which is scheduled to be 5% to 10% by these years, nor the effect of likely load growth that will increase load subject to RPS and thus increase needed clean generation.) Table 6 also shows wind production as as percentage of total Delaware's total load (column 3), 1270 MW_a per EIA—not an RPS benchmark but useful for thinking about potential goals for de-carbonizing the electric system. So from an RPS standpoint, the larger 1200MW project exceeds the requirements for both years. Without offshore wind, there are no candidate resources in Delaware that could meet the existing law's high percentage requirements[40], necessitating payments outside the state for non-Delaware renewables to meet RPS. From a de-carbonization perspective, roughly three 800 MW projects or two 1200 projects, plus some solar, would decarbonize all the state's electric generation.

Table 6. Wind production versus RPS requirements for whole state.

Wind project capacity (MW)	Wind production (MW_a)	Wind as % of all 1270 MW_a state load (EIA)	Wind as % of 1064 MWa load subject to RPS	RPS Requirement 2027 / 2035
800	352	28%	33%	26% / 40%
1200	528	42%	50%	26% / 40%

[39] EIA State Electricity Data, Delaware, 2020. Total sales=11,129,051 MWh divided by 8760 h/yr = 1,270 MW_a average. This EIA number is accurate for the whole state, subsequently we use DNREC's calculation of load per utility.

[40] See Figure 4 for a visualization of the size of the offshore wind resource. The dark blue and purple patches on the map represent old wind energy areas that, if filled with wind projects, could provide 2,800 MW of offshore wind capacity, meeting 100% of Delaware's electric power need with clean electricity. Notice how much larger the new areas enclosed in red lines are.

The RPS requirement is a percentage in relation to each applicable utility's load, whereas Table 6 is for all utility sales in the state combined. Delaware utility-specific loads were tabulated by DNREC[41] for compliance year 2020, as shown in Table 7. (Again we use MW_a rather than MWh/year as in the DNREC source.) The top line of Table 7 shows total sales and the second line load subject to RPS (or "Non-Exempt sales,").

Table 7. Wind and 2020 load per electric utility (allocated proportional to MWh sales).

MW_a	DPL	DEMEC	Dover	DEC	All utilities (≈ sum due to rounding)
Total sales (MW_a)	877	154	81.6	172	1285
Load subject to RPS (Non-Exempt) (MW_a)	762	80.4	51.3	170	1064
Fraction of non-exempt load per utility	0.716	0.0756	0.0482	0.160	1.0
Allocated 800 MW peak generated (MW)	572	60.5	38.6	128	800
Allocated 352 avg. sales (MW_a)	252	26.6	15.1	56.3	352

We can calculate impact per utility in Table 7. An 800 MW project would have a peak wind power output of 800 MW and an average output of 352 MW_a. Delmarva Power has an average non-exempt load of 762 MW_a, meaning that an 800 MW project would at times produce more than Delmarva Power's non-exempt sales. Thus, without re-sale authority, transmission or storage, the occasional excess power would create a financial disadvantage to the company. That would be more true for a 1200 MW project. Next we consider how this would be changed by including all Delaware utilities.

Although we do not know if all utilities will participate in a Delaware offshore wind purchase, we compute how an 800 MW project (352 MW_a) could be allocated to all Delaware utilities, proportionally to their current sales. Table 7 shows the proportional impact in relation to wind peak output and to average wind output.

Table 7 shows that, allocated among Delaware utilities, an 800 MW project produces peak wind power well under each utility's average load, and wind production is less than ⅓ of their electricity sales. Based on this simple comparison, there seems no concern of 800MW being too much power if allocated to all utilities. To make the same comparison for a 1200 MW project, one can multiply the two bottom rows by 1.5. The product shows that the 1200 MW project would be ½ of the energy sold, and at peak wind output it would sometimes exceed the average load of each utility. Thus implementing 1200 MW would require management for such times of excess. To quickly estimate between these two, a 1000MW project would occasionally exceed load for individual utilities. From this simple comparison, an 800 MW project seems readily compatible with current loads and a simple PPA, if allocated to multiple utilities. A 1200 MW project would have to address hours when utilities' share of wind generation exceeds load.

---

[41] The utility level data, on Delmarva Power and Light (DPL), the Delaware Electric Cooperative (DEC), the Delaware Municipal Electric Corp (DEMEC) and the City of Dover, are from RPS reports from the four utilities, supplemented by EIA data on munis. Source of the tabulation is Tom Noyes, Principal Planner for Energy Policy, DNREC. We have here converted MWh/year from the source document, to MW_a to make easier comparisons.

A 1000 MW project would probably be more manageable, but would need some form of contractual protection when purchase exceeds load.

The above analysis of whether wind generation would would sometimes exceed load shows that the 800 MW project would never exceed load, but the 1200 MW would. More wind generation than contracted is not a safety or electrical issue, the concern is that if wind power exceeds load any hour, the utility may be burdened with more allocated energy than it can resell to its own customers. This can be addressed by technical means (transmission and/or storage), or by contract terms regarding resale, or by using the new offshore wind power for more customer classes of the same utilities. In time, it will be solved also by increasing electrical loads due to electrification and by more flexible loads such as EV charging.

From a ratepayer perspective, the larger project produces lower-cost electricity from the wind project, thus it is more favorable to ratepayers as calculated below. There is also a separate "wholesale price reduction" effect that we do not compute here. To explain, any added power generation, including offshore wind power, reduces the cost of other generated electricity in the same market due to competition. Wholesale price reduction has been well documented, for example, a modeled regional addition of 7 GW of offshore wind in New York and New England caused an average 11% reduction in locational marginal price (LMP) (Beiter et al 2020a: 21-24). This ratepayer saving is not included in our cost calculation below; analysis of the wholesale price reduction is complex and beyond the scope of this study. (Nevertheless, we note that larger projects will cause more wholesale price reduction, an additional reason that the 1200 MW project would be more favorable to the ratepayers.)

Wholesale price reduction has significant ratepayer benefits. It will naturally create opposition from existing electricity generators because, after the COD (startup) date, it will lower the wholesale price and, by virtue of new supply, also lower the volume of sales from incumbent generators. Today's generators would logically prefer letting RPS requirements be met by only buying RECs from existing generation, preferably out of state, not by creating new renewable generation in Delaware.

In short, if the state's main concern is to lower ratepayer bills, the 1200 MW project does that through a lower PPA price and more wholesale price reductions. If the goal is to maximally cut CO_2 emissions, the 1200 MW project does more of that. However, without a plan to manage excess power by storage, transmission, and new loads, an RFP might suggest 800 MW with a simple contract, or 1000 MW with contract allowing for occasional excess generation. The alternative would be an RFP that allows larger bids, but only if the the developer's proposal specifies a solution to manage occasional excess power for offtaker utilities.

Delaware utilities currently buy primarily via load-following contracts.[42] To plan ahead, when utilities negotiate purchase renewals from their existing power suppliers, they would inform their suppliers that after wind COD the load will be more variable, because it will be based on the customer load minus wind production. Theoretically this could raise the price per MWh from existing suppliers, however, cases in other regions have shown that the ratepayer savings from wholesale price reduction are larger than the incremental cost for more variable load-following. For example, the Massachusetts PUC found the effect of wholesale price reduction was considerably more than any added cost of load-following or balancing power, resulting in net ratepayer savings from offshore wind (and, see Beiter et al 2020a).

[42] In a load-following contract, the supplier has several types of generators and adjusts output to match what the buyer utility needs at that time.

➤ **Calculating impact on power price** The calculated cost of energy in the last column of Table 2, comparing A-800 with A-1200, gives the incremental savings that would come with a larger project. This section has discussed other costs and savings, in particular wholesale price reduction, and the need to address the problem of offtakers having more power than needed for their load. Solutions exist, but it is beyond the scope of this study to address them. Thus the project size savings below reflect only the better economy of a larger size project itself.

Larger project, CAPEX	- $447/kW
Larger project, OPEX	+ $9.10/kW/year
Effect on power price	- $3.55/MWh

State options to create employment

This section describes additional facilities that could be built as part of an offshore wind project. The SIOW released a report in October estimating the supplies and services needed to meet then-current OSW procurement goals of coastal states from Massachusetts through Virginia—the total was $109B. Some other states have required creation of wind production capital investments such as ports or factories as a part of their bid proposals. Requiring a developer to construct a facility that is not otherwise needed, or one that is sub-optimally located, will increase the cost of the project and therefore increase the cost of electricity. We do not take a position on whether or not this is a desirable tradeoff. We simply here acknowledge: 1) some job creation is built in with a state wind power contract, that is, "free" with the project itself, 2) mandated addition of job-creating facilities to a PPA will raise the contracted electricity price, and 3) some mandated additional facilities have a much larger price effect than others, not necessarily proportional to the industry- and job-creation benefit to the state.

Thus, this report estimates the amount that the electricity cost is increased, so decision-makers can pick which options they think are worth it and which are not. In this section we itemize facilities that we judge to be realistic possibilities for Delaware, along with the approximate capital cost to locate them in Delaware. From that we calculate the effect each would have on the cost of electricity.

Developer contributes to a job-creating entity (e.g. OSW factory)

The potential benefit of an offshore wind job-creating entity is described at a high level to cover the diverse options for facilities and industries. We pick an illustrative $150 million cost, close to the amount that some states have spent or have directed developers to spend, for a substantial offshore wind facility. An RFP that requires such facilities would typically identify a specific existing facility to expand, or perhaps a facility type. For instance, within this price range, a developer could invest partial funding for a marshaling port or full funding for ground support and heavy-lift dock preparation for a factory. Alternatively, the RFP could require job creation via developer funds set aside for the state to picks the most economic job-producing investments, rather than leaving choice to the discretion of the developer. Example facilities are described in subsequent sections. Some are appropriate for this expenditure, while other facilities do not necessarily need developer or state payments in order to be constructed and create jobs. We are not arguing for or against this approach, only showing the impact on price of various job-creating facilities.

➤ **Calculating impact on power price** To calculate the impact on the cost of electricity, we assume that the developer pays this amount to contribute to the new offshore wind facility at the time of other capital investments.

Developer cost, increased CAPEX	$150M
Effect on power price	+ $3.40/MWh

Operations and maintenance port in Delaware

Operations and Maintenance (O&M) ports are used to stage routine maintenance and repairs on the offshore wind project. O&M Ports typically serve one wind project or a few projects that are close together. US developers usually make power purchase offers that commit to building an O&M port within the state that is hosting their project; the developer believes that the jobs created may incentivize the state to pick their proposal. Developing an O&M port in Delaware is more practical if the project is located in the waters off of Delaware or somewhere nearby for daily visits.

A typical port would include a parts warehouse, vessel support, offices, meeting and training rooms, and mooring for vessels. An O&M port for an 800 MW project is relatively easy to create by modifying existing small craft facilities, requiring about 5 acres (2 hectares) and an investment of about $15M, plus vessels (Parkison and Kempton 2022, Table 1). Such a port might employ 30-60 workers. Because it is in operation for the entire 30-year life of each project, an O&M port may account for the largest single category of job-years generated by one state project. Note that a port or factory could account for more job years if it is selling components or services to multiple projects.

As offshore wind projects proliferate, there is an economic cost associated with a single-project, small O&M facility, which may be less cost-efficient than combining O&M into fewer regional O&M ports and dividing the cost among projects. For several reasons, such a multi-project port would most likely located outside of Delaware.

➤ **Calculating impact on power price** Our Base Project model assumes an O&M port to be used just for the Delaware project. To inform an RFP decision on the use of a shared O&M port versus requiring one in Delaware and gaining the subsequent employment advantages, we estimate savings in capital and operations expenditures for a shared facility, then determine the extent that a shared facility would reduce electricity cost. This calculation may not fully account for the reduced trips offshore of the combined facility, for which we lack cost data, so the savings of shared port are likely a bit higher than those given below. The calculation shows 60¢/MWh savings associated with choosing a shared port, therefore there is a 60¢/MWh cost to require an individual O&M port in Delaware.

Shared O&M port, CAPEX	- $5M
Shared O&M port, OPEX	- $1M/year
Effect on power price	- $0.60/MWh

Marshaling port

To date, US offshore wind ports have relied substantially on state subsidies and developer payments. Of course, the developer payment is not free, it is just shifted to the ratepayer. Such ports are in very high demand and Delaware has an unusually good location available for a critical port type, the marshaling port (in the area of Delaware City, see House et al, 2020, Parkison & Kempton 2022). This facility could be built from private investment, possibly supplemented with Federal or other public infrastructure funds. If so, it's possible that neither the state nor the developer would need to provide funding. There would still be a role for the state. First, it would be easier to attract tenants to that port, whether for marshaling and deployment or for manufacturing, if Delaware has initiated a procurement process. Second, the value of a marshaling port depends on not having overhead obstructions, such as bridges or new overhead power lines downstream (say, downstream from Fort Delaware State Park). Therefore an important non-financial state contribution would be careful consideration of the damage from overhead obstructions before permits are awarded to new potential obstructions.

Another option is that the state could require the winning developer to use a Delaware marshaling port. However, current market analysis finds that marshaling ports will be in high demand for developers, so requiring them to use it is likely unnecessary (Parkison & Kempton 2022). If the state or developer were to financially assist the construction of a marshaling port, the projected investment range and impact on electricity cost would be similar to that calculated above for a "job-creating facility."

➤ **Calculating impact on power price** The Delaware Bay has desirable marshaling port characteristics based on location and site attributes, including sites near Delaware City on the Delaware side and near Salem on the New Jersey side. This option would create many jobs, but construction wouldn't necessarily be tied to the RFP process nor to state investment. Thus we make no separate cost estimation for this facility nor evaluate the impact on cost of energy.

Effect on power price	Not calculated

Workforce development center

A group at the University of Delaware (UD) has proposed an offshore wind worker training program in Sussex County that would provide safety training and could grow to incorporate other types of blue collar worker training such as offshore construction, turbine maintenance, etc. Whether that proposal advances, the state may want to consider some form of workforce development for offshore wind as it could provide both a self-supporting service as well as a path for Delaware tradespeople and youth to enter this industry. The number of workers requiring training and certification is estimated by Maersk Training to be 1 technician per MW installed, with a refresher course every 2 years. Such a training center could employ about 20 people on an ongoing basis, some part-time, and would provide entry for many local residents to higher-skilled jobs in this growing industry.

Such a center could be privately funded, or draw on Federal or local government startup funding. Tuition would cover operating expenses. Regardless of whether state or developer funding is involved, workforce training is more likely to be built, attract more trainees, and provide more employment benefits, if Delaware has begun a procurement process.

➤ **Calculating impact on power price** Training centers in other states have been financed in part by developer funds, thus affecting the RFP price. We calculate the price impact of developer contribution, without necessarily recommending that be included in the RFP. Here we assume as an example for analysis, a training center building with equipment costing $4M, split in half between a project developer and the entity operating the training center.

Cost of center, CAPEX	$2M
Effect on power price	+ $0.10/MWh

Offshore wind visitor center

This could be built as a small visitor attraction, with the benefit of educating local residents about the project. For example, such a facility could be a one-room unconditioned building with outside signage, and an inside display of public education materials about the project , a computer screen showing project images, with output wind speed, and power. It could it could be co-located with other tourist attractions. A landowner (for example, a municipality, DNREC, the developer, or a local business), and an operations and maintenance party would need to be identified for the center to be constructed.

➤ **Calculating impact on power price** Below is the estimated cost of building and of annual maintenance, excluding land purchase. Establishment of an offshore wind visitor center would be a cost for the developer, and would require collaboration with the land owner and/or the local government.

Developer, CAPEX	$30K
Developer, OPEX	$15K/year
Effect on power price (result is less than 1¢/MWh; rounds to zero)	+ $0/MWh

Delaware's future potential with offshore wind

We briefly consider the longer-term potential of offshore wind power development for Delaware. A single 800 MW offshore wind project would achieve 28% RPS goal by 2027, which would be a large step toward Delaware's legislated obligation of 40% by 2035. It would do so with in-state generation and would be connected to the Delaware transmission grid. An offshore wind project would further create new O&M jobs and enterprises like those mentioned in this report. This section considers next steps that the state could consider after a first offshore wind project. These actions would not be decided upon or endorsed now, but instead can act as a guide for future consideration of how decisions today might prepare Delaware for an easier transition to the future.

First, looking at total of Delaware's offshore wind potential. Comparing with other states, several now have 100% renewable electricity goals. For Delaware to accomplish this in the future, it would need approximately three 800 MW projects or two 1200 MW projects plus some production from solar resources. Figure 4 suggests that the potential resource can easily do this, as do more detailed calculations (Kempton et al 2007). To reach 100%, the state would also have to make adjustments by a combination of transmission, energy storage, and/or contractual adjustments, as discussed in the section on "Right sizing" above.

Given the rapid growth of offshore wind, this report mentioned several facilities that could be built due to a power solicitation, including an O&M facility and port, a marshaling port, and possibly some offshore wind manufacturing; as well as smaller enterprises, for example, a worker training center and a visitor center. Those primarily require Delaware to participate in the OSW market, do not necessarily require state financial subsidy or credit. These industries are more likely to locate in Delaware if the state is participating in an offshore wind power solicitation.

One example of local business opportunity comes from building and operating transmission. An 800 MW Delaware project alone might only require connection to the Indian River substation. But that, along with the two Maryland offshore projects that are already requesting connection through Delaware, would definitely require transmission upgrades. Rather than sizing transmission just for those three offshore wind projects, the state could request that the required transmission corridor to leave “empty ducts” underground and “extra arms” on towers, running from offshore to the Indian River substation, so that a later expansion of power would cost much less[43]. After bringing the added power to Indian River, selling that power would require that more transmission lines be routed to load centers to the west and north. A transmission provider could compare, for example, two possible routes: 1) transmission could be extended by supplementing the cost of an above-ground 230 kV line that would run from Indian River to the north and connect to the E-W 500 kV line, therefore supplying power to Maryland, Pennsylvania and New Jersey,[44] or 2) transmission could extend from Indian River to the west, then an underwater cable could carry electricity under the Chesapeake Bay to a high power link like Calvert Cliffs.[45] Either transmission project would be able to export electricity in times of excess power in Delaware.

Another potential use for abundant offshore wind electricity is production of hydrogen (H_2) in Delaware. Green hydrogen can be generated using renewable electricity to power electrolysis of water, yielding oxygen as a byproduct along with H_2 fuel. Green hydrogen is a completely clean fuel, and it can be chemically converted to ammonia, then to other e-fuels or fertilizer; as green products these may fetch a higher price. New York, which is already considering expansion beyond its 9,000 MW offshore wind plan, is discussing use of some of offshore wind power to produce e-fuels to help meet the state’s net-zero goals for all fuels. This report does not explore these derived industries, but we note that a new market could develop due to low-cost electricity from offshore wind.

From a climate mitigation perspective, if the state joins with other states in our region and continues to increase goals for lower CO_2, an offshore wind power procurement would allow Delaware to meet or exceed the current RPS target. The offshore wind resource near Delaware is large enough that the state could set standards as high as desired, up to 100% clean electricity from OSW (Kempton et al. 2007; Sheridan et al. 2012). The schedule in Table 5 suggests that 5½ years are required from writing the RFP to clean power flowing for each installation; however, if desired, the state could initiate a new solicitation every 2-3 years so that the first project is under construction while paperwork and studies are in progress for the second, etc. We do not here take a position whether or not to plan this parallel process nor do we take a position on a later 100% target, rather, we are pointing out that it is an option for more rapid de-carbonization within the framework that is given here for one project. A decision between one project or a sequence need not be made at the outset.

Given the size of the BOEM Draft Call Area map (Figure 4), it is clear that there is a large energy resource near our shores. The federal government is preparing to lease it to private companies. Delaware can ignore these developments and let other states proceed, or can begin to develop that resource with one project, take steps to allow further expansion if desired later, and prepare for the associated industries that will come with it.

---

[43] We haven’t calculated the precise cost of empty ducts but it is a very small addition to the cost of a transmission corridor.

[44] As an approximation, a two-circuit 230kV line can carry 800 MW and a 500 kV AC double line can carry 3,000 MW. Source: Ryan Pletka and John Finn, 2009, “Western Renewable Energy Zones, Phase 1” Report NREL/SR-6A2-46877. Accessed at: https://www.nrel.gov/docs/fy10osti/46877.pdf

[45] The link from Indian River to Calvert Cliffs was the route of the planned but abandoned Pepco Holdings “MAPP” project.

Summary of the effects of policies and added facilities on power price

This section summarizes options from Part II. The top options in Table 8 are the individual state options and regulatory clarifications to reduce the price of offshore wind electricity. Then it summarizes options for added facilities or employment and their impact on price. The method for calculating effects on price using the Base Project is described in Appendix C, for those who want to test out other potential increases or reductions in costs.

As summarized in Table 8, the first set of policy options can reduce the developer's project costs, and thus the bid price of offshore wind power. In contrast, the second set considers the addition of facilities or other expenses that could raise the cost of power. Although the cost effect of some options can only be approximated, these estimates provide some guidance for state decision-makers to prioritize and pick among options.

Table 8. Summary of price impacts of stat actions, relative to Base Project (two pages).

	Capital Cost Δ $x1000 (or $/kW if so marked)	OPEX Δ ($x1000/ year) or $/ kW/yr if marked	Change in PPA price (Δ $/MWh), (negative is savings)	Cause of change in PPA price
Options for electricity cost reduction				
RFP for 1200 MW rather than 800 MW, in same location, compare A-800 to A-1200	- 447 $/kW	+ 9.1 $/kW/yr	-3.55	Only project cost tabulated; see text on other cost factors
Selected proposal is for a more distant location like Site B; compare A-1200 with B-1200, see A vs. B in Figure 4 ✖	+ 789 $/kW	+ 3.90 $/kW/yr	12.60	See Table 2 and discussion of B-1200
Slowdown or delays prevent developer from meeting federal ITC deadline ✖	+614,000	0	20.42	higher energy price due to lost ITC credit
Request that BOEM designate more WEAs near Delaware ✔	0	0	-3.00	more competition; assume 1% lower ROE
Defined process for cable landing that runs from the ocean, under the beach, to a substation✔	0	0	-5.50	Less construction risk, less delay
Coordinated single 3GW transmission for 3 projects rather than one cable per project ✔	- 86 $/kW	0	-2.30	shared single cable and converter stations, savings allocated per power capacity
Clarifications to state permitting and guidance from DNREC to avoid delay ✔	0	0	-3.40	reduce risk of development delay by 6 months

	Capital Cost Δ $x1000 (or $/kW if so marked)	OPEX Δ ($x1000/year) or $/kW/yr if marked	Change in PPA price (Δ $/MWh), (negative is savings)	Cause of change in PPA price
State obtains SAP, deploys met buoy 2 years prior to RFP (would create a cost to the state but yields a lower power price) ✔	+1,500	0	-2.10	less risk in bid price
			-1.10	Quicker or no SAP by developer
Utility buys RECs from developer as required by current law, using the schedule in Appendix B ✔	0	0	-1.77	A set REC price schedule lowers PPA price compared with unknown market price. Discussed in RFP requirements.
Options for job-creating offshore wind facilities				
O&M port, incremental cost of separate O&M port for one project	+ $5,000	+1,000	0.60	Base model already includes this cost, deleting it would save $0.60
Offshore wind observation center	+30	+15	0	Added energy cost rounds to $0/MWh
Share cost of a training center for OSW workers	$2,000	0	0.10	State or developer could pay part of capital facilities.
Contribution to large job-creating facility (e.g. offshore wind factory)	$150,000	0	3.40	Developer contributes to factory

The check ("✔") next to six items in Table 8 denotes cost-reduction policies to consider for action, and the x ("✖") indicates two cost-increasing risks that confer no benefit and should be avoided. Only one item (the met buoy) requires state spending or subsidy, however it has expected ratepayer savings many times the cost. If all six denoted cost-saving actions were implemented, and the two cost-increasing ones avoided, the estimated total savings would be $19.17/MWh.

Some savings projections may be optimistic, may not be attempted by the state, may not all be achieved, or may not be fully additive. On the other hand, the two prior SIOW state reports have both underestimated the amount of cost savings possible. As an overall quantity, we summarize the effect of these six cost-saving options to conclude that between $0 and $19.17/MWh may be achieved below our Base Project price if the state takes some or all of these optional actions. Even if only part of this price reduction is achieved, it would provide significant savings to ratepayers and would likely put Delaware's OSW power price below recent purchases of wholesale power by Delaware's regulated utility. With the low wind PPA price and the expected but not calculated benefit of wholesale price reduction, an offshore wind project, structured as recommended here, would lower ratepayer costs, not raise them.

The second set of options in Table 8 lists the job-creating opportunities, with their pros and cons discussed in the text. Several are very low cost and some may have zero ratepayer or taxpayer cost but nevertheless could benefit from some state facilitation.

Conclusions

Offshore wind is expanding rapidly on the US East Coast. Recent technology improvements and industry scale-up have brought wind power prices to competitive levels for many utilities, including in the mid-Atlantic, based on recent market price data. Given the data and considerations of this report, we find that the state of Delaware now has the means to procure cost-competitive offshore wind power. If the state decides to proceed, the legislature would need to establish a procurement process and designate Agencies to create and monitor the steps leading to the commercial sale of energy from a wind developer to one or more utilities. The designated Agencies would develop an RFP, review proposals and select a winning proposal. Through these procedures and actions, the state holds the power to determine what are acceptable proposals, influence the resulting electricity price, and incentivize any associated business development and employment. State policymakers and Agency representatives can choose what objective to emphasize—low power price, job creation, etc.—by directing both RFP requirements and bid evaluation criteria.

The state has multiple levers to influence price. In addition to having a well-structured RFP that facilitates competition, Table 8 summarizes six actions to take, and two to avoid, to reduce the price of power. If these are taken successfully, is is likely that the offshore wind price will be equal to or lower than Delaware's current price of energy. There is no need to create a new incentive nor to use state monies to subsidize the price, given the current competitiveness of wind energy costs in the regional electricity market. If desired, the state could order that RECs shall be sold from the project to meet Delaware's RPS requirements in existing law. For subsequent projects, the cost analysis here implies that under current conditions, it is not necessary to create additional subsidy or REC schemes, or to subsidize offshore wind power (this could change if the Federal ITC expires before industry prices decline proportionally, or if prices rise for other reasons).

For project sizes below 800MW, the price of electricity per MWh increases steeply. Therefore, the recommended capacity of a Delaware wind project is 800MW-1200MW, larger sizes above 800 MW further reduce costs but also will sometimes be more difficult for the power to be absorbed cost-effectively. If capacities above 800 MW are solicited, the RFP should request adjustments to power contracts during times that minimum load is coincident with wind peak production, or have the bidder include transmission or storage infrastructure in the proposal. The problem of excess power is partially managed by having more than one utility offtaker in Delaware.

The state should consider collaborating with Maryland and their wind developers on common transmission planning. The Maryland wind projects would benefit from a common corridor, and possibly shared lines, through Delaware's Coastal Zone to an interconnection point such as Indian River substation, near Millsboro. Coordination on shared transmission would reduce cost and reduce environmental and community impacts from laying the cable. It would be much more difficult to collaborate on an offshore wind farm itself given the role of each state's respective PSC and local priorities; also note that there would be no advantage of a dual-state single wind project rather than each state directing its own power purchase. Although we do not believe a dual-state RFP or power contract to be practical, that would not preclude a bidder planning to build a Delaware project sequentially with a project they do for another state, keeping the turbines and power generation separate, yet achieving many of the economies of a single larger build.

By simply deciding to procure offshore wind and initiating this process, it is more likely that some job-creating facilities will be constructed in Delaware, regardless of whether such facilities are incentivized in the procurement process. Therefore, the state may or may not decide it desirable or necessary to embed job-creation into a power contract. The construction of some facilities may proceed independent state or developer financing. If Delaware decides to add requirements as additions to the wind procurement, data here can be used to prioritize based on price impact.

With an efficient procurement process, competing bids, and a bid evaluation emphasizing least-cost, Delaware is likely to be able to obtain wind power starting 2027 or 2028 that meets all of the legislatively required need for RECs in a single project, at a price within the range of recent power prices. In the process a single 800 MW offshore wind project would meet an RPS level of 33%, and would reduce total conventional electric generation (thus reduce state CO_2 emissions) by 28%.

By taking further actions beyond the above-specified efficient procurement, if the state takes the cost-reducing policy and administrative actions outlined herein, we calculate that wind power price could be below that of existing Delmarva wholesale power purchases.

References Cited

(note: references to statute and to some URLs are given in page footnotes)

American Wind Energy Association (now ACP), 2020, "U.S. Offshore Wind Power Economic Impact Assessment," accessed at https://supportoffshorewind.org/resources/

Beiter, Philipp, Lena Kitzing, Paul Spitsen, Miriam Noonan, Volker Berkhout, and Yuka Kikuchi. 2021. "Toward Global Comparability in Renewable Energy Procurement." Joule, May. https://doi.org/10.1016/j.joule.2021.04.017.

Beiter, Philipp, Jessica Lau, Joshua Novacheck, Qing Yu, Gord Stephen, Jennie Jorgenson, Walter Musial, and Eric Lantz. 2020a. "The Potential Impact of Offshore Wind Energy on a Future Power System in the U.S. Northeast." Golden, CO: National Renewable Energy Laboratory. NREL/TP-5000-74191. https://www.nrel.gov/docs/fy20osti/74191.pdf.

Beiter, Philipp, Jenny Heeter, Paul Spitsen, David Riley. 2020b. "Comparing Offshore Wind Energy Procurement and Project Revenue Sources Across U.S. States." Golden, CO: National Renewable Energy Laboratory. NREL/TP-5000-76079. https://www.nrel.gov/docs/fy20osti/76079.pdf.

Beiter, P. et al., 2021, "Wind power costs driven by innovation and experience with further reductions on the horizon." *WIREs Energy Environ.* 2021;e398, accessed at https://doi.org/10.1002/wene.398

Bernstein, Matthew and Jonathan Kern, 2021, "Offshore Wind Transmission Study: Phase 1 Results." PJM Transmission Expansion Advisory Committee. Report, accessed at https://www.pjm.com/-/media/library/reports-notices/special-reports/2021/20211019-offshore-wind-transmission-study-phase-1-results.ashx

Bonou, Alexandra, Alexis Laurent, Stig I. Olsen, 2016, "Life cycle assessment of onshore and offshore wind energy-from theory to application," *Applied Energy Vol.* 180, pp 327-337

Buonocore, Jonathan J., Patrick Luckow, Jeremy Fisher, Willett Kempton, Jonathan I. Levy, 2016, “Health and Climate Benefits of Offshore Wind Facilities in the Mid-Atlantic United States”, *Environmental Research Letters* 11 (2016) 074019. doi: 10.1088/1748-9326/11/7/074019

Energy Information Administration, 2020, “New electric generating capacity in 2020 will come primarily from wind and solar,” accessed at https://www.eia.gov/todayinenergy/detail.php?id=42495

Energy Information Administration, 2021, “Renewables account for most new U.S. electricity generating capacity in 2021”. 11 January 2021, accessed at https://www.eia.gov/todayinenergy/detail.php?id=46416

Environmental Protection Agency (US), 2021a, “Greenhouse Gases Equivalencies Calculator - Calculations and References” Updated April 28, 2021. accessed at: https://www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references

Environmental Protection Agency (US), 2021b, “Estimating the Health Benefits per Kilowatt-Hour of Energy Efficiency and Renewable Energy” Report 452R21001, second edition May 2021. accessed at https://www.epa.gov/sites/default/files/2021-05/documents/bpk_report_second_edition.pdf

Harris, Doreen, 2015, “Large-Scale Renewable Energy Development in New York: Options and Assessment,” NYSERDA Report 15-12, 1 June 2015, accessed at https://www.nyserda.ny.gov/-/media/Files/Publications/PPSER/NYSERDA/Large-Scale-Renewable-Energy-Development.pdf

House, E., Roy, Z., Sundstrom, S., and Tulsky, E., 2020, “Feasibility assessment for an offshore wind marshalling port in the Delaware Bay,” Report, University of Delaware Office of Economic Innovation and Partnerships, accessed at https://cpb-us-w2.wpmucdn.com/sites.udel.edu/dist/5/8632/files/2020/07/OEIP-Delaware-Bay-Port-Assessment.pdf

Internal Revenue Service, 2021, “Beginning of Construction for Sections 45 and 48; Extension of Continuity Safe Harbor for Offshore Projects and Federal Land Projects,” Notice 2021-05, accessed at https://www.irs.gov/pub/irs-drop/n-21-05.pdf

Kempton, Willett, Cristina L. Archer, Richard W. Garvine, Amardeep Dhanju and Mark Z. Jacobson, 2007, “Large CO2 reductions via offshore wind power matched to inherent storage in energy end-uses,” Geophysical Research Letter, 34, L02817. DOI: 10.1029/2006GL028016

Kempton, Willett, Stephanie McClellan and Deniz Ozkan, 2016, “Massachusetts Offshore Wind Future Cost Study,” University of Delaware Special Initiative on Offshore Wind, Report, March 2015. accessed at https://cpb-us-w2.wpmucdn.com/sites.udel.edu/dist/e/10028/files/2020/01/MA-Offshore-Wind-Future-Cost-Study-rev-4-April-16.pdf also accessible from https://sites.udel.edu/ceoe-siow/publications/

Lazard, 2020, “Lazard's Levelized Cost of Energy Analysis—Version 14.0,” accessed at https://www.lazard.com/media/451419/lazards-levelized-cost-of-energy-version-140.pdf

Liberty Group, 2021, “Technical Consultant Final Report Delmarva 2021 SOS Auctions,” presentation to Delaware Public Service Commission on 17 Feb 2021.

MacGregor, Donald G., Paul Slovic, M. Granger Morgan, 1994, “Perception of Risks From Electromagnetic Fields” Risk Analysis Vol 14 (5), pp 815-828. https://doi.org/10.1111/j.1539-6924.1994.tb00293.x

Maryland Public Service Commission (MD PSC), 2021, “Maryland PSC Decision Expands Offshore Wind Development,” press Release, 17 December 2021.

McClellan, Stephanie, Deniz Ozkan, Willett Kempton, Andrew Levitt, Heather Thomson, 2015, “New York Offshore Wind Cost Reduction Study, Final Report”. University of Delaware Special Initiative on Offshore Wind, Report, accessed at https://cpb-us-w2.wpmucdn.com/sites.udel.edu/dist/e/10028/files/2020/01/071516-New-York-Offshore-Wind-Cost-Reduction-Study-ff8.pdf also accessible from https://sites.udel.edu/ceoe-siow/publications/

Musial, Walt, Phillip Beiter, Paul Spisen, et al., 2021, “2020 Offshore Wind Technologies Market Report” Draft Report of May 10, 2021, National Renewable Energy Lab.

New Jersey Senate, 2021, “An Act concerning offshore wind projects and amending P.L. 2010, c.57,” New Jersey, bill, accessed at https://www.njleg.state.nj.us/2020/Bills/S4000/3926_I1.HTM

Parkison, Sara B. and Willett Kempton, 2022,. “Marshaling Ports Required to Meet US Policy Targets for Offshore Wind Power,” *Energy Policy* Vol. 163, April 2022, 112817. DOI: 10.1016/j.enpol.2022.112817.

Sheridan, Blaise, Scott D. Baker, Nathaniel S. Pierre, Jeremy Firestone, and Willett Kempton, 2012, “Calculating the offshore wind power resource: Robust assessment methods applied to the U.S. Atlantic Coast,” *Renewable Energy*, 43, p224-233. DOI:10.1016/j.renene.2011.11.029,

Stehly, Tyler, Philipp Beiter and Patrick Duffy. 2020. “2019 Cost of Wind Energy Review.” Golden, CO: National Renewable Energy Laboratory. NREL/TP-5000-78471. https://www.nrel.gov/docs/fy21osti/78471.pdf.

US Department of Agriculture (USDA), 2021, “USDA Agricultural Projections to 2030.” Long-term Projections Report OCE-2021-1, accessed at https://www.usda.gov/sites/default/files/documents/USDA-Agricultural-Projections-to-2030.pdf

Vann, Adam, 2021, “Wind Energy: Offshore Permitting” Washington, DC: Congressional Research Service, Report R40175, updated March 8, 2021, accessed at https://sgp.fas.org/crs/misc/R40175.pdf

White House, 2021, “Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide. Interim Estimates under Executive Order 13990,” by Interagency Working Group on Social Cost of Greenhouse Gases, United States Government.

Wiser, R., Rand, J., Seel, J. et al., 2021, “Expert elicitation survey predicts 37% to 49% declines in wind energy costs by 2050,” *Nature Energy* 6, 555–565, accessed at https://doi.org/10.1038/s41560-021-00810-z

Appendix A - Sources for Table 1, US offshore wind purchase agreements

Table A-1 gives the sources for information on price used to make Table 1 in the text. (Empty "project" rows here correspond to those in Table 1.) In most cases, the electricity price in Table 1 has been adjusted from that published. We uniformly use inflation of 2.0%, discount rate (real) 3.92%, and present costs in real 2021 dollars. If the escalation factor is set at the rate of inflation (several of those projects listed do not), that would mean that the power prices would be the same in real dollars when the project is opened and during each year of the life of the project. A similar table can be found in Musial et al. 2021, Table 8. This table adds more recent projects, and we feel that the adjustments we use in Table 1 give more comparable electricity prices across projects and with our three modeled future Delaware projects.

Table A-1. Sources for Table 1, US offshore wind purchase agreements

Project	Source of price Information
Skipjack 1	https://www.psc.state.md.us/wp-content/uploads/PSC-Awards-ORECs-to-US-Wind-Skipjack.pdf
Skipjack 2	https://www.psc.state.md.us/wp-content/uploads/Order-No.-90011-Case-No.-9666-Order-Granting-Offshore-Wind-Renewable-Energy-Credits.pdf
Revolution	http://www.ripuc.ri.gov/eventsactions/docket/4929-NGrid-ScheduleNG-5(REDACTED).pdf
	https://www.energy.gov/sites/default/files/2019/08/f65/2018%20Offshore%20Wind%20Market%20Report%20Presentation.pdf
South Fork	https://www.lipower.org/wp-content/uploads/2019/10/LIPA-First-Offshore-Wind-Farm-Doc-V19_102819-FINAL.pdf
US Wind 1	https://www.psc.state.md.us/wp-content/uploads/PSC-Awards-ORECs-to-US-Wind-Skipjack.pdf
US Wind 2	https://www.psc.state.md.us/wp-content/uploads/Order-No.-90011-Case-No.-9666-Order-Granting-Offshore-Wind-Renewable-Energy-Credits.pdf
Sunrise Wind	https://www.nyserda.ny.gov/-/media/Files/Programs/offshore-wind/osw-phase-1-procurement-report.ashx
Atlantic Shores	https://www.pjm.com/-/media/planning/services-requests/atlantic-shores-offshore-wind-project-1.ashx
Ocean Wind I	https://njcleanenergy.com/files/file/6-21-19-8D.PDF
Ocean Wind II	https://www.bpu.state.nj.us/bpu/pdf/boardorders/2021/20210630/ORDER%20Solicitation%202%20Board%20Order%20-%20OW2%20B.pdf
Vineyard Wind	
Empire Wind	https://www.nyserda.ny.gov/-/media/Files/Programs/offshore-wind/osw-phase-1-procurement-report.ashx
Empire Wind 2	https://www.nyserda.ny.gov/-/media/Files/Programs/offshore-wind/Empire-Offshore-Wind--executed.ashx
Beacon Wind	https://www.nyserda.ny.gov/-/media/Files/Programs/offshore-wind/beacon-wind-executed.ashx
Mayflower Wind	

.

Appendix B - Existing Delaware RECs

Here we propose a possible way to allocate the existing REC requirement to a new offshore wind project. To do so, we use 26 Del.C. § 351 – § 364 which sets a precise number of RECs that regulated utilities are required to purchase (column 2), and we suggest a required REC price (column 3) to be set by the legislature. As an example, here we give that is slightly below the expected market price for RECs at each year. If this were included as a required part of an offshore wind solicitation law, it would slightly lower the REC cost to utilities, result in REC payments supporting projects for Delaware, and thus modestly increase employment in Delaware rather than other states in the region. This would also allow the developer to lower the electric cost by the same amount, resulting in lower prices to Delaware to ratepayers. (Whereas REC payments to out of state renewables do not.)

An 800 MW wind project would produce RECs of approximately

800 MW * 44%CF * 8760 h/y = 3,083,520 RECs/year

Therefore, the number of RECs produced by a commercial size project is considerably above the Delmarva requirement to purchase for all years of applicable law.

Year	Number of RECs to be purchased	Set price ($/MWh)	REC revenue to wind seller ($)
2024-25	574728	14	8046192
2025-26	694,245	15	10413675
2026-27	710,941	16	11375056
2027-28	950,035	16	15200560
2028-29	966,731	15	14500965
2029-30	1,087,235	13	14134055
2030-31	1,240,401	11.5	14264611.5
2031-32	1,393,753	8.5	11846900.5
2032-33	1,473,852	6.5	9580038
2033-34	1,776,430	6	10658580
2034-35	1,909,996	5	9549980
2035-36	2,003,493	4	8013972
Total			137584585

Appendix C - Use of CREST energy cost spreadsheet

Separate spreadsheets are provided for four example project models, A-800 Base Model, A-1200, and B-1200 with HVDC, and A-800 with DE REC schedule payments rather than assumed market REC values. File names are:

A-800	CREST_Wind_1.4_A-800-BaseProject.xlsx
A-800 RECs	CREST_Wind_1.4_A-800 with DE RECs.xlsx
A-1200	CREST_Wind_1.4_A-1200.xlsx
B-1200HVDC	CREST_Wind_1.4_B-1200-HVDC.xlsx

The cost of energy results are found in the spreadsheet on tab "Summary Results". The net nominal leveled cost of energy, in ¢/kWh is in cell D14; we do not use that here. The net year-one cost of energy (COE) is in cell D7, this is what we call the nominal PPA price. However, this is expressed in nominal dollars in the project COD year, in this case 2027. For comparison of prior OSW prices in other states against the projected Delaware future price, this report expresses all PPA prices in 2021$. With the assumed 2% inflation rate, the 2021$ price adjusted for 2027 - 2021 (=6 years) is:

$$Price_{2021\$} = \frac{Price_{2027\$}}{1.02^6} = \frac{Price_{2027\$}}{1.12616}$$

For example, the Base Project model, 800 MW at location A, shows a 2027 PPA ("first year") price of 8.05 ¢/kWh, expressed in ¢/kWh and nominal money for COD year 2027$. To convert to 2021$, first convert 8.05¢/kWh to wholesale units of $80.50/MWh, then adjust 2027$ to 2021$ by the equation above, yielding $71.48/MWh in 2021$. To check, this is the result given in the first line of Table 2.

To test the price effect of changes in policy or in assumptions to the Base Project, the parameters of any of the four models above can be changed to see the effect on price. Enter the new value into the appropriate spreadsheet cell. Then, the change in Nominal leveled cost of energy, per above, is converted to 2021$ and compared to the original Base Model cost.