UNIVERSITY OF DELAWARE | College of Earth, Ocean, & Environment
SPECIAL INITIATIVE ON OFFSHORE WIND

Massachusetts Offshore Wind Future Cost Study

Prepared by

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Acronyms

AEP	annual energy production
AMI	Area of Mutual Interest
BIWF	Block Island Offshore Wind Farm
BOEM	Bureau of Ocean Energy Management
CapEx	capital expenditures
CF	capacity factor
COD	commercial operation date
CRMF	Cost Reduction Monitoring Framework
DOE	U.S. Department of Energy
DWW	Deepwater Wind
FC	financial close; triggers ability to enter contracts for construction (project financing) or drawdowns for construction expenditures (balance sheet financing); for this study, U.S. construction was assumed to start one year after FC and last 2 years followed by 6 month site commissioning prior to wind farm operation.
FID	final investment decision; Typically used in context of equity decision, stage in a financial agreement where conditions have been satisfied or waived and documents executed; triggers draw-downs and project execution.
GW	gigawatt
HVAC	high-voltage alternating current
HVDC	high-voltage direct current
IO&M	installation, operations, and maintenance
IRR	internal rate of return
kW	kilowatt
LCOE	levelized cost of energy
MW	megawatt
N/A	not applicable
Nm	nautical miles
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
OCS	Outer Continental Shelf
OEM	original equipment manufacturer, e.g. turbine manufacturer
OpEx	operational expenditures
OSW	offshore wind
POI	point of interconnection
PPA	power purchase agreement
REC	renewable energy credit
SIOW	Special Initiative on Offshore Wind
TCE	The Crown Estate
USD	United States dollar
WACC	weighted average cost of capital
WEA	wind energy area
WRF	weather research and forecasting model

Executive Summary

This study models the cost of electricity from 2,000 MW of offshore wind energy, deployed off the coast of Massachusetts throughout the period 2020-2030. We find that costs will be far lower than previously contracted prices for offshore wind in the New England region and that costs will continuously lower throughout a build-out during the decade, due to ongoing technology and industry advances and the effects of making a Massachusetts market visible to the industry.

The "levelized cost of energy" (LCOE) was above 24¢/kWh for previously contracted projects in New England including the Cape Wind project proposed for Massachusetts and the Block Island Wind farm off the coast of Rhode Island – the latter is currently in construction and will be the US's first-built offshore wind farm.[1] The results of the modeled 2,000 MW build-out show, first, that the LCOE for the initial offshore wind project -- 16.2¢/kWh -- will be much lower than projects to date. Second, the study shows that costs continue to decline in subsequent builds, so that by the last tranche of a 2,000 MW pipeline of projects, the LCOE reaches 10.8¢. Table ES-1 below displays the LCOE's across the analyzed build-out, with and without transmission costs included, and including learning effects.

Table ES-1. LCOEs for 2,000 MW build-out - 2020 -2030[a]

	Tranche A 400MW COD 2023	**Tranche B 800MW COD 2026**	**Tranche C 800MW COD 2029**
LCOE without transmission (2016¢/kWh)	12.4¢	9.8¢	7.9¢
LCOE with transmission (2016¢/kWh)	16.2¢	12.8¢	10.8¢

[a] Cost reductions reflect market visibility and learning effects.

[1] Using published PPA terms in Musial and Ram (2010), Large-Scale Offshore Wind Power in the United States: Assessment of Opportunities and Barriers, p. 119, and converted to levelized cost.

The metric of this study is calculated LCOE, which does not consider any Federal production tax credit, state renewable energy credits (RECs) or potential carbon fees, any of which would lower the actual price below our LCOE projection. The study does not address the overall comparative value of the technology versus other ways of producing electricity. This is because LCOE does not consider system benefits, job creation, environmental, or health benefits, any of which would improve the relative cost of offshore wind power.

In addition to the anticipated technology improvements that will lower the cost of offshore wind energy through the next decade, the primary mechanism of the observed downward trajectory illustrated in Table ES-1 is development of offshore wind at scale. Commitment to scale provides "market visibility" to the industry, which lowers cost over time. Table ES-2 illustrates two recent one-off project proposals in the area, compared with three tranches of the modeled pipeline of 2,000 MW. Compare in particular the first and third lines, 468 and 400 MW, two projects of about the same size. Tranche C benefits from subsequent technology improvements, but also benefits from the much greater market visibility, the two effects together generating the substantial reduction in LCOE seen in the last column.

Table ES-2. Impact of scale: Comparison of New England LCOEs

Project	Anticipated Financial close (year)	Project size (MW)	OSW Market Visibility in New England (MW)	LCOE (¢/kWh)
MA project proposed	2014[a]	468	400	24¢[b]
RI project under construction	2015	30	30	30¢[c]
Tranche A (this study)	2020	400	2,000	16.2¢
Tranche B (this study)	2023	800	2,000	12.8 ¢
Tranche C (this study)	2027	800	2,000	10.8¢

[a] Proposed Cape Wind project has not yet reached financial close.
[b] Calculated from National Grid PPA terms, reported in Musial and Ram (2010), converted to LCOE.
[c] Calculated from PPA terms reported in Musial and Ram (2010), converted to LCOE.

Market visibility reduces cost by generating competition among developers and their suppliers and by creating a community of experienced project investors who see less risk and thus expect lower rates of return. Market visibility is achieved by government policy that commits to the build-out of a sequence of projects, as opposed to a policy for one single project, which has been previously seen in Massachusetts and other East coast states. Also, building a series of projects leads to experienced workforce for subsequent projects, which becomes more efficient as they learn by doing.

From the authors' previous work on cost reduction and U.S. state policy, there are potentially additional cost savings unrelated to scale that can be affected by state policy that further reduce risk. The provision of site characteristic data, requiring winning bidders to share certain information in advance of future builds, and investing in infrastructure and workforce development, all are policy options that can reduce cost, but were not analyzed in this study.

As a check on the results, we benchmarked our LCOE results with two studies that report costs and cost trends seen in Europe. The cost trend for Massachusetts's projects is consistent with the trend line of declining cost among recent and planned European projects. The first Massachusetts tranche analyzed yields a LCOE that is still at the high end of European cost projections. By the end of the last tranche of a 2,000 MW pipeline, Massachusetts LCOEs have reached a price range that is competitive in today's U.S. market.

To conduct the study, we elicited estimates of each of the major costs of developing, building, financing, and operating an offshore wind project—from industry experts who are actively creating or receiving bids for components and services for projects in the region. This set of inputs was used to calculate LCOE.

Collecting forward-looking data from industry participants involved in a particular market differs from the approach of most prior studies, which estimate future costs from already-built projects in Europe. Because it can require six years from conceiving to financing, to building, to operating an offshore wind project, using already-built projects to infer costs of future projects just now conceived would give data as much as 12 years out of date--misleading in a rapidly-changing field of technology and industrial development.

Introduction

There is currently discussion in Massachusetts regarding a possible requirement that utilities in the state purchase electricity generated by offshore wind, approximately 2,000 MW over a ten-year period.[2] The only offshore wind projects in New England, the proposed Cape Wind project, and the under-construction Block Island Wind Farm (BIWF), do not provide relevant cost information. These two projects were "one-off", i.e. not part of a planned sequence of offshore wind at a multi-project scale. Also, Cape Wind's design was specified many years ago and BIWF is a small demonstration-size project.

This study calculates what the levelized cost of energy (LCOE) would be from a pipeline of offshore wind projects in the Massachusetts-area Wind Energy Areas (WEA's). We assume the deployment of 2,000 MW of offshore wind (OSW) in the currently existing lease holds within designated WEAs of New England, with deployment occurring between 2020 and 2030. The study considers multiple factors that have been hypothesized to impact the LCOE of OSW energy when it is deployed at the gigawatt (GW) scale.

[2] Legislation introduced in 2015 ("An Act to Promote Energy Diversity") would have required a series of solicitations for offshore wind totaling 8,500,000 MWh/year by 2030. At a 45% CF that would be about 2,100 MW capacity which we here refer to as 2,000 MW capacity. In 2016, an omnibus energy bill is being drafted in the Massachusetts House Energy Committee, which may include an offshore wind carve-out.

LCOE is used as a metric to compare across projects and across energy sources. It gives the price that would be charged for electricity, if based on actual costs, and if charged at the same rate every year of the project life.

Background

Offshore wind power has been identified, analyzed and discussed for a decade as a potential electricity resource for US coastal states, with the Northeast of particular interest. Studies have identified the northeast resource as a much larger clean energy resource than on-land wind or rooftop solar, with the Northeast offshore wind potential enough to supply all electricity used by those coastal states.[3] The resource is close to Eastern load centers and many areas have strong winds at times approximately corresponding to peak load hours.[4,5] Wind trade organizations also claim that, due to the size of components and transportation costs, and labor-intensive construction and operations, offshore wind has the potential to create a new industry and thousands of jobs that cannot be exported out of the region.[6] For example, construction and installation jobs and operations and maintenance jobs – inherently local jobs – constituted more than 50% in new offshore wind jobs in the UK between 2010 and 2013, a period of significant growth in offshore wind there.[7,8]

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[3] 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 Letters*, 34, L02817. doi:10.1029/2006GL028016

[4] Garvine, Richard W. and Willett Kempton, 2008, Assessing the wind field over the continental shelf as a resource for electric power, Journal of Marine Research 66 (6): 751-773. (Nov 2008).

[5] Michael J. Dvorak, Eric D. Stoutenburg, Cristina L. Archer, Willett Kempton, and Mark Z. Jacobson, 2012, Where is the ideal location for a US East Coast offshore grid? *Geophysical Research Letters*, Vol. 39, L06804, doi:10.1029/2011GL050659.

[6] http://www.ewea.org/fileadmin/files/library/publications/reports/Deep_Water.pdf; For MW # cite to 2013 EWEA report available at http://www.ewea.org/fileadmin/files/library/publications/statistics/European_offshore_statistics_2013.pdf and most recent EWEA report (first half of 2014) available at http://www.ewea.org/statistics/offshore/

[7] Renewable UK (2013). *Working for a Green Britain and Northern Ireland 2013-23*, p. 29. http://www.renewableuk.com/en/publications/index.cfm/working-green-britain

[8] Renewable UK. http://www.renewableuk.com/en/news/press-releases.cfm/record-breaking-year-of-growth-for-uk-wind-energy

The primary drawback to adoption of offshore wind power has been the cost of electricity produced.[9] Although one high-profile case of opposition of coastal residents has captured media attention,[10,11] public view shed opposition has not been a significant source of opposition in other US or European installations.[12] Based on the second author's multi-year experience with state governments considering offshore wind, the primary barrier to adoption has been cost. Power Purchase Agreement (PPA) prices for most of the earliest proposed projects were well over market price for electricity.[13]

This has been true in other regions, for example in Europe, where now more than 11 GW of offshore wind energy are deployed. The European market, driven in large part by binding national CO_2 goals, went through an initial period of high cost and the need for large subsidies to make project economics work. An additional problem in a market with few technology suppliers is that pricing can be set to the subsidy rather than set by costs. Like other new technologies, for example personal computers or solar photovoltaic panels, initially high costs can be brought down by constantly improving technology, greater competition among OEMs as well as parts and services suppliers, mass production, and industrialization of the installation and O&M operations. For offshore wind, as described next, an additional driver of cost-reduction was that governments who were paying subsidies told the industry that they would have to bring prices down to unsubsidized market levels in order to continue, as discussed next.

[9] Levitt Andrew C.; Kempton Willett; Smith Aaron P.; Walt Musial; and Jeremy Firestone, 2011, Pricing offshore wind power. Energy Policy 39 (10): 6408-6421. doi:10.1016/j.enpol.2011.07.044

[10] Robert Whitcomb, Wendy Williams, 2007, Cape Wind: Money, Celebrity, Energy, Class, Politics, and the Battle for Our Energy Future. New York: Public Affairs books.

[11] Kempton, W., J. Firestone, J. Lilley, T. Rouleau and P. Whitaker, 2005, The Offshore Wind Power Debate: Views from Cape Cod, Coastal Management 33 (2): 119-149. Published doi:10.1080/08920750590917530

[12] Firestone, Jeremy, Willett Kempton, Meredith Blaydes Lilley, and Kateryna Samoteskul, Public acceptance of offshore wind power across regions and through time, 2012, *Journal of Environmental Planning and Management*, 55:10, 1369-1386. doi:10.1080/09640568.2012.682782

[13] See Musial, Walt and Bonnie Ram. 2010. Large-Scale Offshore Wind Power in the United States: Assessment of Opportunities and Barriers. NRELTP-500-40745. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/wind/pdfs/40745.pdf., p. 119.

European public-private initiatives to reduce cost

Acknowledging offshore wind's unique benefits and its high costs, early in this decade European national governments together with industry initiated a number of cost reduction efforts. From the Carbon Trust's Offshore Wind Accelerator – a joint partnership of nine developers initiated to reduce costs by 10% in time for the United Kingdom's "Round 3" of offshore wind deployment – to The Crown Estate's[14] Cost Reduction Pathways Study, the UK arguably took a leadership role in pushing and facilitating offshore wind cost reduction. In 2011 The Crown Estate undertook an evidence-based study to identify and quantify cost reduction opportunities for the offshore wind industry. The study identified the drivers and dependencies of offshore wind costs, through consultation with industry, and "provided a platform for the government, project developers, the supply industry and operators to align future activities and maximize cost reductions."[15] The report generated confidence – and in turn a challenge to the UK offshore wind industry – that offshore wind could reach electricity costs of £100/MWh (14¢/kWh)[16] for projects reaching Final Investment Decision (FID) in 2020.[17] That challenge spawned a variety of public-private partnership work streams to pursue the technological innovation, supply chain efficiencies and financing hurdles that would successfully achieve the £100/MWh target.

In addition to efforts in the United Kingdom, industry and government agencies in Denmark also developed formal collaborations to reduce the cost of offshore wind energy to reach a target of €100/MWh (11.2¢/kWh) for offshore wind energy. [18]The "Cost Reduction Forum" was launched in September, 2014 by Offshoreenergy.dk, the Danish government's official national knowledge center and innovation network for the Danish

[14] The Crown Estate is the quasi-governmental agency in the United Kingdom, which owns and manages the collection of land and holdings that belong to the British monarch, including the seabed.

[15] The Crown Estate (2012). Offshore Wind Cost Reduction Pathways Study. http://www.thecrownestate.co.uk/media/5493/ei-offshore-wind-cost-reduction-pathways-study.pdf

[16] Throughout this text when electricity prices are given in foreign currency we convert to USD, using March 2016 conversion rate of £1 = $1.43 and €1 = $1.11. When the units are $/MWh, we also convert to the more widely familiar consumer unit ¢/kWh ($100/MWh = 10¢/kWh).

[17] By Final Investment Decision in 2020, not projects going into operation in 2020.

[18] Germany as well analyzed the potentials of decreasing the levelized cost of energy (LCOE) of offshore wind power in Germany over the period 2013-2023. For more details see Fichtner Prognos (2013), *Cost Reduction Potentials in Offshore Wind Power in Germany*.

offshore industry.[19] In addition, the Danish Wind Industry Association launched Megavind, a partnership of Danish industry, academics, and government who work in a coordinated effort to accelerate technological innovation to make offshore wind energy competitive with other electricity generating resources. Together they set an ambitious goal to cut the levelized cost of offshore wind energy 50% for investment decisions in 2020 compared to comparable sites with investment decisions in 2010.[20]

The Netherlands, and Belgium also are engaging in activities to reduce the cost of offshore wind energy, for example, carrying out site characterization activities and partially permitting areas -- prior to holding auctions for development rights and power off-take agreements. Both of these activities can reduce uncertainty and provide developers and investors with ability to predict costs and performance with improved certainty. Less risk generally means that developers can reduce contingencies and offer lower power prices.[21]

Measured progress towards cost reduction in Europe

Following the UK's government and industry's initial period of joint activity, they continued to work together to assess offshore wind energy costs and evaluate progress in bringing those costs down; the UK's "Cost Reduction Monitoring Framework" (CRMF) as it is referred to, carries out two activities: 1) evaluating the progress of cost reduction activities across the spectrum of key cost drivers in an offshore project and 2) collating actual costs information on projects which have achieved the milestones of Final Investment Decision and/or Works Completion.[22]

[19] Funded by Danish Agency for Science, Technology and Innovation.
[20] Megavind (2013). "The Danish Wind Power Hub."3
[21] National Renewable Energy Lab (2015). 2014-2015 Offshore Wind Technologies Market Report, p. 18.
[22] The Cost Reduction Monitoring Framework is a collaboration between the UK Offshore Wind Programme Board, the Offshore Wind Industry Council, the UK Department of Energy and Climate Change and The Crown Estate.

The CRMF reported in 2014 that progress in reducing the cost of offshore wind energy had been made during the years 2010-2014.[23] "For projects reaching FID, the industry average LCOE was £142/MWh (20.3¢/kWh) in 2010-2011 and £121/MWh (17.3¢/kWh) in 2012-2014. For projects reaching Works Completion, the industry average LCOE was £136/MWh (19.4¢/kWh) in 2010-2011 and £131/MWh (18.7¢/kWh) in 2012-2014." Larger turbines, improved technology, and efficiency were credited with lowering costs as was greater competition in the supply chain. The monitoring effort underscored however the need for systematic improvement in work force and risk reduction with respect to supply chain failures as areas in need of continued emphasis to achieve cost reductions.

In 2015, an independent analysis commissioned by Statkraft UK further examined the progress being made and projected where the industry could be in the next decade,[24] their summary table is reproduced below as Table 1 (with £ converted to US$). Despite water depth and distance to port and grid increasing as closer and shallower sites are developed, there is nevertheless an overall downward trend in cost of electric energy, seen in the rightmost column.

[23] Deloitte, August 2015 "Establishing the Investment Case -- Wind Power" http://www2.deloitte.com/content/dam/Deloitte/dk/Documents/energy-resources/Deloitte-Establishing-wind-investment.pdf
[24] BVG Associates, 2015, *Offshore Wind: Delivering More for Less*. http://statkraft.com/globalassets/4-statkraft-uk/offshore_wind_more_for_less_pages.pdf

Table 1. Historical and projected factors affecting cost of offshore wind projects in the UK (Source: BVG Associates 2015; USD added)

Year	Turbine size (MW)	Project size (GW)	Water depth (m)	Distance to port / grid (km)	Wind speed at 100m (m/s)	Cost of energy offshore wind ($/MWh)
2005	2 – 3	< 0.1	15 – 25	10 – 30	8.5 – 9.0	225 – 275
2010	3 – 4	0.3 – 0.6	25 – 35	10 – 60	9.0 – 9.5	217 – 272
2015	6 – 8	0.6 – 0.8	20 – 45	20 – 120	9.3 – 9.7	150 – 194
2020	7 – 9	0.6 – 1.2	30 – 45	50 – 240	9.5 – 10.0	109 – 157
2025	8 – 10	0.6 – 1.2	30 – 45	50 –240	9.5 – 10.2	92 – 149
2025 (repowered)	8 – 10	0.2 – 0.4	15 – 25	10 – 60	8.5 – 9.0	
2030	10 – 12	0.6 – 1.2	30 – 45	50 – 240	9.5 – 10.2	76 – 142
2030 (repowered)	10 – 12	0.3 – 0.6	25 – 30	10 – 60	9.0 – 9.5	

The Danish Energy Agency with Denmark's energy systems operator (Energinet.dk) have also tracked offshore wind costs and reductions, including future cost reductions anticipated.[25] Table 2 below indicates the Danish government's assessment of the expected innovations in offshore wind technology and the concomitant reductions in offshore wind energy costs. The bottom three rows are costs, and we add a rightmost column to show the reduction in cost of components and services from 2015 to 2030. The highest cost capital items are projected to drop by 30%. The 2050 column (outside the time scope of this study) shows continued decline in costs.

[25] Danish Energy Agency and Energinet.dk (2012). Technology Data for Energy Plants –Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion. Område: Statistik & fremskrivninger. ISBN/Nr.: 978-87-7844-931-3

Table 2. Projected costs of offshore wind subsystems and operations (From Danish Energy Agency and Energinet.dk, with column added for cost reduction 2015-2030).

Technology	Large wind turbines offshore (year of investment decision)				Cost change 2015 – 2030 (%)
	2015	2020	2030	2050	
Average generating capacity per turbine (MW)	4 – 6	6 – 10	10 – 16	10 – 20	
Rotor diameter (m)	110 – 155	155 –180	180 – 200	180 – 250	
Hub height (m)	80 – 100	95 – 115	115 – 125	115 – 155	
Annual average plant capacity factor (%)	46 – 48	48 – 50	50 – 52	51 – 53	
Availability (%)	96	97	97	98	
Technical lifetime (years)	25	25	25	30	
Construction time (years)	2 – 4	2 – 4	2 – 4	2 – 4	
Financial data					
Specific investment, total costs (M€/MW) at 20m depth and 30km from shore ex. Grid connection to shore	3	2.5	2.1	1.8	– 30%
Grid connection to shore (M€/MW)	0.36	0.35	0.33	0.32	– 8%
O&M (€/MWh)	19	17	16	15	– 16%

A recent market report that combines several of these sources is the September 2015 U.S. National Renewable Energy Laboratory's (NREL) *U.S. Offshore Wind Market Report*. The *Market Report* is one of a variety of reports funded by the U.S. Department of Energy, providing quantitative, independent data for use by the wind industry and its various stakeholders, including policy makers, regulators, developers, financiers, and supply chain participants.[26] From the report:

> "In 2015, Denmark and the United Kingdom held competitive auctions for price support, which resulted in the lowest power prices for offshore wind in recent history. Vattenfall won the competitive tender for the 400-MW Horns Rev III project in Denmark, and will receive a subsidy of 770 DKK/MWh ($134/MWh) for the first 50,000 MWh of operation. In the United Kingdom, [Contract for Differences] CFDs were awarded to Mainstream Renewable Power for the 448-MW Neart Na Gaoithe project and to Iberdrola for the 714-MW East Anglia ONE project. The winning bids for these projects were £114.4/MWh ($184.5/MWh) and £119.9/MWh ($193.3/MWh), respectively."[27,28]

[26] NREL, p. 6.
[27] NREL, p. 77.
[28] The developer of East Anglia ONE reached Final Investment Decision in February 2016 for the project. (http://www.bbc.com/news/uk-england-suffolk-35650590). It was reported that the developer secured a price support contract of £119/MWh through the UK's first renewable energy auction process.

Megavind, the Danish public-private partnership, has also pointed to the Horns Rev III tender as illustration that the industry is reaching its targets, citing a 32% reduction in cost, from the Anholt wind farm also in Denmark (tendered in 2010). Deloitte in an August 2015 report writes " . . . innovation and standardization are expected to help the industry in realizing its cost reduction targets." Deloitte continues, reporting that Horns Rev III and Anholt tenders correspond to a reduction of 28% before adjusting for general inflation."[29]

Figure 1 is drawn from the NREL Market report. The cost/MWh scale was converted from Pounds and Euros and adjusted by NREL to $2014[30] per MWh, and reflects Real LCOE, excluding subsidies. The black line in Figure 1 from 2012 to 2020 is the goal set by the UK government, in partnership with industry, for cost reduction.[31] (The extension of the black line to 2030 as shown by NREL is under discussion in the UK but is not now an agreed-to UK goal.) The colored shapes represent actual wind projects, with those before 2016 (squares) representing an average of operating built projects, and those of 2016 and after (triangles and circles) representing signed contracts to sell power at a set rate. The green hollow circle is a project in Danish waters—in that country the transmission cost is paid by the grid operator not the developer, so the NREL analysts used a second filled circle to show their estimate of project cost including transmission, making the filled green circle comparable to the other prices represented by filled points on the graph.

Figure 1 shows several things. First, the UK government set a price reduction target, and industry did not make that target the first year, did slightly better the second year shown (blue squares) and all subsequent projects have continued to stay below the goal.

[29] Deloitte (2015). "Establishing the Investment Case – Wind Power," p. 10.
[30] Using US Bureau of Labor Statistics calculators, for example, at http://www.bls.gov/bls/inflation.htm
[31] The black line from 2020-30 indicating a lower target of £85/MWh by 2030 is not the official UK government target, according to reviewers of this study.

The key driver of these initial reductions, according to communications with UK peer reviewers for this study, were the targets set through industry and government collaboration. According to the CRMF, the commercialization and rapid adoption of turbines with larger nameplate ratings (6–8 MW) and increased power conversion efficiency was the key technological driver of lower costs. These larger machines reduce CapEx and OpEx by minimizing the number of units that must be installed and maintained while increasing performance. Other innovations in vessel technology and balance of systems are also contributing to the lower cost levels. NREL analysis suggests that favorable macroeconomic factors also play a role, such as stable commodity prices, low activity in the offshore oil and gas sector, and international exchange rates.[32]

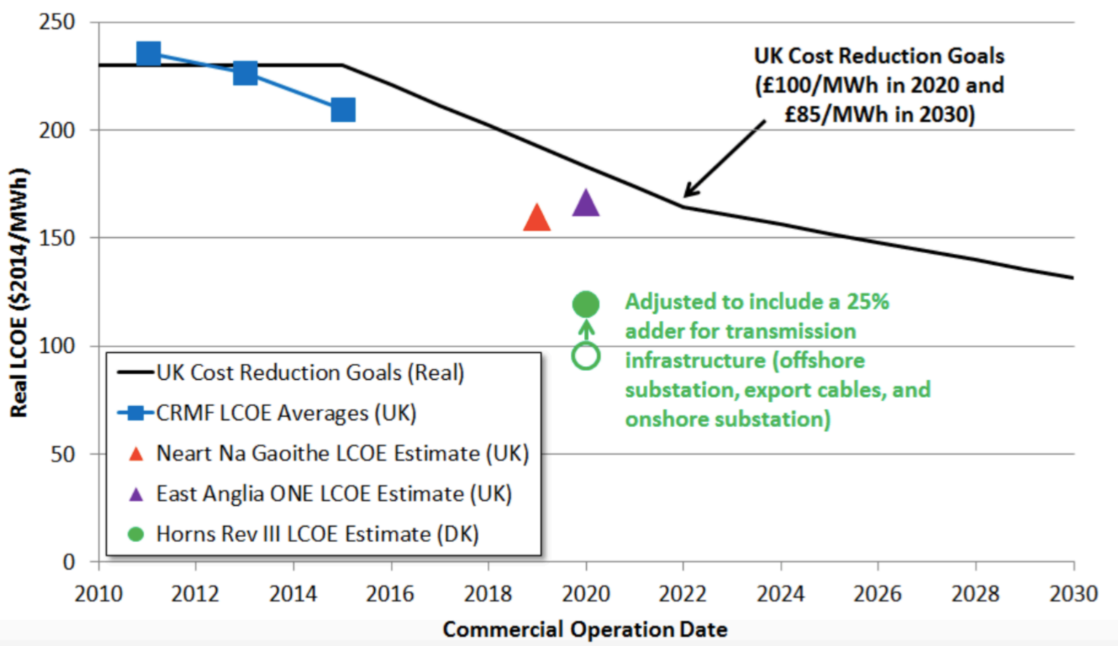

Figure 1. LCOE of multiple UK and Danish offshore wind projects.[33,34] Each project's Real LCOE is calculated and converted to $2014 USD. Source: NREL.

[32] NREL, p. 80.
[33] NREL, p. 80.
[34] As noted in the NREL report, the source for Figure 1, there are significant uncertainties associated with comparing power off-take prices because of differences in project scope (e.g., in the United Kingdom, developers pay for grid connection, whereas in Denmark that responsibility lies with the TSO), market structure (e.g., tax rate and depreciation structure), site characteristics (e.g., wind speed, water depth, and distance from shore), and contractual terms and conditions (e.g., contract length and treatment of inflation).

Second, looking at now-contracted projects awaiting FID (triangles and circle), the cost reduction trend continues with the Vattenfall winning bid for Horns Rev 3 being notably lower than a linear curve from the built projects.

As one more background study, a research note by Bloomberg New Energy Finance (BNEF) examined potential cost reductions in offshore wind. BNEF undertook the examination in order to understand how feasible the industry's targets are, and how they could be achieved.[35] According to their analysis, BNEF found that offshore wind cost is likely to reach as low as \$122/MWh (12.2¢/kWh), and they argue that a 20% learning curve would be required to reach the UK's \$110/MWh (11¢/kWh) target by 2020.[36] In a separate "bottom up" analysis, BNEF examined the key components of offshore wind CapEx and OpEx and their respective cost reduction potentials to determine how the targets could be met. Similarly, their "bottom-up analysis" suggests offshore wind industry could reach \$122/MWh (12.2¢/kWh), still short of the UK target.[37] However, BNEF assumed an industry target of 2020 for a *commissioned* project.[38] While press reports often describe the target as "£100/MWh by 2020," the substantive underlying reports and analyses regarding the European targets clarify that the targets are for projects reaching *Final Investment Decision (FID)* by 2020, not commissioning in 2020.[39] The time interval from FID to commissioning is roughly two to three years. When BNEF's erroneous target date is corrected the UK's 2020 target would be much closer to being met than BNEF's summary suggests.

Real LCOE offers a better metric for comparison and can be approximated by averaging the total revenue stream that the project would anticipate over its lifetime and accounting for the effects of inflation (See NREL report for further discussion of assumed anticipated revenue streams).

[35] Bloomberg New Energy Finance (August 2015). "Route to offshore wind 2020 LCOE target: From riches to rags." Report distributed to Bloomberg clients.

[36] BNEF, p. 1.

[37] BNEF, p. 4

[38] BNEF, p. 4.

[39] The Crown Estate (2012). Cost Reduction Pathways Study, p. vii.

Implications for U.S. LCOEs

The dearth of real U.S. project proxies, with none for any potential market of scale,[40] the considerable activity in the global industry to reduce cost, and policymaker questions about costs led SIOW to examine what the cost of energy from offshore wind projects would be in the near future in the US market under different policy assumptions. Our first study was of the New York Bight, examining the impact of the anticipated cost reductions in the global market on New York projects, and how US or state policy would further affect price.[41] SIOW, working with New York State Energy Research and Development Authority, obtained cost figures for the technology that is expected to be in the market for projects that will reach FID in 2020 and applied those costs figures to a hypothetical build-out of projects off of Long Island, NY over the period 2020-2023, a plausible time frame for development and installation there.[42]

SIOW found that by moving to the larger, more efficient turbines expected to be available when New York area projects are likely to reach Financial Close, along with other technology and supply chain innovations, the LCOE would be 22% lower than if built with the smaller turbines that had been bid in earlier projects on the East coast.[43,44]

SIOW's New York study also examined the impact of learning in the installation and operations and maintenance of offshore wind farms, as capacity grows in New York and

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[40] PPA's for projects proposed and power contracts negotiated in the U.S. either in the last decade (Cape Wind) or earlier this decade (BIWF) do not provide any real indicator to what costs for U.S. projects today can achieve. Cape Wind's power contract was bid and negotiated long before the successful cost reduction initiatives in the global offshore wind industry. BIWF is a small demonstration project. And other more recently bid projects such a Dominion's Virginia Offshore Wind Technology Advancement Project, Fishermen's Energy's Atlantic City project and a demonstration size floating project in Coos Bay, Oregon are all very small demonstration projects that do not reflect projects costs of larger wind farms. Additionally none of these contracted nor bid US projects have been bid within the context of a visible, longer-term context of a visible pipeline of projects – the approach contemplated in the legislation currently being considered in Massachusetts.

[41] McClellan et al (2015). New York Offshore Wind Cost Reduction Study.

[42] Input data used by SIOW to calculate LCOE's were obtained from BVG Associates.

[43] McClellan, p. S-4.

[44] Costs reflecting incremental technological innovation were modeled in a hypothetical build-out of four projects, in different water depths and distances from shore; the cost reductions across the buildout reflect not only the technological advancement but also the differences in project site characteristics.

in the region. Learning effects further reduced the LCOE of the hypothetical New York offshore wind projects.[45]

Lastly, the study examined the impact on LCOE of various New York State policy measures that were identified by the study team as potentially decreasing costs, above and beyond the impact of technology advancement and industry learning. Those policy measures included creating "market visibility," (a committed-to sequence of projects), reducing project risk through a variety of both revenue policy design steps as well as pre-development steps to increase visibility on site conditions.

Policy measures had various impacts, with market visibility having the greatest impact. Market visibility reduces cost by generating competition among developers and their suppliers, and by creating a community of experienced project investors who see less risk and thus expect lower rates of return. Market visibility is achieved by government policy that commits to the build-out of a sequence of projects, as opposed to a policy for one single project, as previously seen in Massachusetts and other East coast states.

In short, the study found that New York Bight projects would benefit from the cost reduction efforts of the global industry, but that state policy commitment to scale creates market visibility and creates learning effects, with both significantly lowering the cost of offshore wind energy. Market visibility and scale are in contrast with one-off projects like Cape Wind or BIWF.

SIOW felt a Massachusetts-specific study would be helpful to understand recent industry changes and the effects of the policies being discussed. Therefore this study seeks to understand what the LCOE would likely be from 2,000 MW of OSW deployed in the currently existing lease holds within designated WEAs of New England, with deployment occurring over the years between 2020 and 2030.

[45] McClellan, p. S-6.

Methods

To calculate cost for potential Massachusetts projects, we identified a potential sequence of build areas within WEAs, performed expert elicitation on expected costs, and calculated LCOE. These are described below.

How to elicit cost data for not-yet-built US projects?

Given the rapid decline in costs and lack of built projects in the US, standard cost estimation methods as cited above, did not seem adequate. Due to the planning time required, an offshore wind project with lease today might see financial close in 2020, construction completed in 2023. Existing studies that analyze projects recently completed in 2015 in Europe could be 6 to 8 years behind the pricing of future projects we seek for the first Massachusetts projects. Thus, studies of already-build projects are inherently backward-looking. In addition, they are in the North Sea not US waters.

Expert elicitation

To address the backward-looking and Europe-data problems, we identified a source for regionally-relevant, up-to-date cost data. Three offshore wind developers have leased the right to develop ocean area off Massachusetts and Rhode Island, and we believe that all of them have recently requested quotations from turbine manufacturers and contractors, at these sites or in the region. Additionally, at least three turbine suppliers have examined this area or other US sites to understand costs and their potential market. This group of developers and suppliers has therefore presumably been carefully evaluating the metocean conditions and logistics of the area, and we inferred that they would already have either quotations or careful internal evaluations of cost. (Note: in this industry, the turbine manufacturers (OEMs) are more likely to cost estimate the entire project than do other suppliers e.g. vessel operators, which is why we sought cost estimates from developers and OEMs, not other suppliers).

One major concern from these expert sources is confidentiality—they will be bidding against each other and would not allow any of their individual data to be released to their competitors. To solve the confidentiality problem, the second author (McClellan) requested, and eventually obtained, agreements with these experts that they would provide cost data to us and we would develop a single number from their collective inputs. The experts required that no individual's inputs would be revealed; only the combined average number would be published.

Appendix B provides more detail on how we performed the expert elicitation and how we dealt with possible sources of bias. In brief, we carefully picked expert teams, and elicited from them each of the component costs, using expert elicitation methods developed by Morgan et al.[46] Then we evaluated each expert's cost for each component, and averaged those costs. In most cases we also made one to three follow-up queries or interviews to understand how they answered our cost questions, including their assumptions. When we felt some sources were less well informed, we weighted them less in the average, but all estimates were included in each of the resulting cost component inputs, with the results shown in Appendix A. As noted, the transmission cost was calculated separately, by our own analysis, and is added to the total LCOE as a separate step. Transmission cost inputs are also located in Appendix A. All other inputs used in the LCOE calculations can also be found in Appendix A.

In post-elicitation reviews of the inputs with the experts, we determined that two did not correctly follow instructions regarding the assumption of market visibility. We had instructed the experts to give component costs without assuming market visibility, that is, to provide cost inputs for each tranche, assuming that it was the only one being built. In post-elicitation follow up interviews we discovered that two companies' commercial analyses had already begun, based on a pipeline of projects, and that, the costs they provided to us included an assumption of market visibility. Therefore, we did not apply any additional market visibility to those costs for our analyses. To examine the effect of market visibility on cost, we compare with two proposed projects in the region that had no market visibility at all beyond their one project build.

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[46] Morgan, M. Granger (1990). Uncertainty: A Guide to Dealing with Uncertainty in Quantitative and Risk and Policy Analysis. Cambridge University Press, Cambridge, MA.

Levelized cost of energy

LCOE is a commonly used metric for the cost of electricity produced over the lifetime of the project. The general inputs for calculating LCOE for OSW are capital expenditures, operating and maintenance costs, cost of capital, and the expected annual energy production of the OSW farm. For a project generating electricity from fuel, the cost of fuel would be added to the LCOE.[47,48]

Because contracts can be short-term and can include escalators or fuel adders, the LCOE is a metric that improves the ability to compare across fuel sources. Many renewable sources can assure a price over the entire life of the project. Fuel-based generation can be estimated over long periods only in relation to predictions of future fuel prices, so their LCOE inherently has an uncertainty over the lifetime of the facility.

LCOE normally does not include any subsidies, RECs, carbon credits, or health benefits. For example, when the US production tax credit is active the PPA price could be lower than the LCOE by 2.2 ¢/kWh.[49] Or, if the emissions benefits were considered as part of the price, studies of land-based wind in the mid-Atlantic show that each MWh power produced by wind, by displacing existing generation, produces savings in health and climate change costs of $81 to $110MWh (8.1 – 11¢/kWh).[50] None of those are included in the LCOEs or in the analysis here.

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47 LCOE is the equivalent unit cost ($/MWh or ¢/kWh) that has the same present value as the total cost of building and operating a generating plant plus investor returns over the power plant's life divided by total electrical generation. See explanation with Levelized Cost of Electricity Calculator, NREL, http://www.nrel.gov/analysis/tech_lcoe.html

48 LCOE calculation does not include the cost of balancing, which would be minimal for the 2,000 MW build contemplated here. One U.S. utility's calculation for adding 2 to 3 GW of wind is an integration cost of $3.70/MWh (0.37¢/kWh) (Final Report: Public Service Company of Colorado 2 GW and 3 GW Wind Integration Cost Study. Attachment 2.13-1. Prepared by Xcel Energy Inc. and EnerNex Corp. August 19, 2011. A general discussion is (Michael Milligan, Erik Ela, Bri-Mathias Hodge, Brendan Kirby, Charlton Clark, Jennifer DeCesaro, and Kevin Lynn, and Debra Lew, 2011, "Cost-Causation and Integration Cost Analysis for Variable Generation." Technical Report NREL/TP-5500-51860, June 2011.

49 See Musial and Ram 2010, Large Scale Offshore Wind Power in the United States: Assessment of Opportunities and Barriers. NREL/TP-500-40745, p. 119.

50 Jonathan J. Buonocore, Patrick Luckow, Gregory Norris, John D. Spengler, Bruce Biewald, Jeremy Fisher and Jonathan I. Levy, 2016, "Health and climate benefits of different energy-efficiency and renewable energy choices" *Nature Climate Change*, **6**, 100–105, Table 5. DOI: 10.1038/nclimate2771

We use a public-domain cost of energy modeling tool, NREL's CREST, that accepts the component cost inputs as described above, and calculates LCOE as an output.[51] Thus, by describing our procedure, providing all inputs used, and using a public tool to develop LCOE, our results are transparent, and can be confirmed by any other analyst.

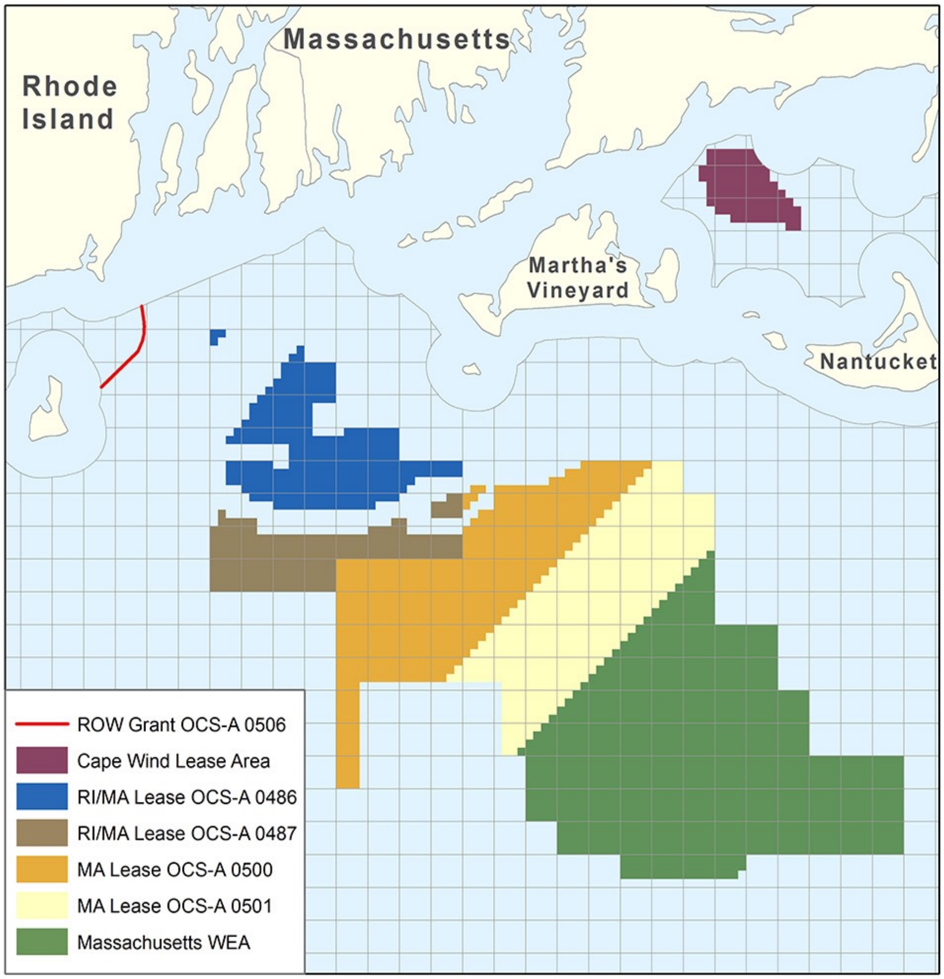
LCOE, an analytic measure, is comparable but not identical to commercial measures such as a PPA price. A PPA price is a negotiated or bid quantity, and the seller may set that price differently from LCOE based on many factors, such as favorable tax treatment. A PPA can have a price escalator through time, so that price is lower initially and higher later, by definition not "levelized." A PPA price is generally quoted only for the energy, in $/MWh or ¢/kWh, while in fact a wind generator may sell other electricity products such as capacity or ancillary services, in which case the energy PPA alone could be lower than LCOE as calculated. In addition is the developer's market strategy. For example, to maximize market share a seller could bid below cost, or a monopolistic seller without competition might bid well above the LCOE.

Identifying tranches and sites to model LCOE

There are two federally designated wind energy areas in the Massachusetts area, the Rhode Island and Massachusetts area of mutual interest (RIMA AMI) and the Massachusetts Wind Energy Area (MA WEA). Auctions were held by the Bureau of Ocean Energy Management (BOEM), which leased RIMA AMI and two of the three areas of MA WEA in 2014 and 2015. These areas are illustrated in Figure 2.

[51] (http://www.nrel.gov/analysis/models_tools.html),

Figure 2. Wind Energy Areas. The RIMA WEA (blue plus brown), and two areas of the MAWEA (tan and yellow) are now leased. The green area of MA WEA has not yet been leased.



We developed three "indicative tranche areas" for OSW development that capture a range of the site characteristics. The site characteristics of the three tranches are displayed in Table 3.

Table 3. Site Characteristics for three tranches.

Tranche	Water depth	Wind speed (m/s)	Distance to port (miles)	Distance to interconnect	
				Offshore	Onshore
A	35.8	9.3	43.3	40 miles	0.2 miles
B	38.8	9.4	45.5	38 miles	4 miles
C	38.8	9.4	45.5	48 miles	4 miles

Figure 3 shows an illustrative map of Tranches A, B and C. Each tranche area is actually a blend of possible choices for each tranche, so the red lines on Figure 3 show an approximation, not precise boundaries. Note that Tranche A is smaller, 400MW, whereas Tranches B and C are larger to accommodate 800MW each. The approach of using tranches, rather than developer lease areas or individual projects, is to simplify the analysis, to not assume one most cost-effective build size, and to not link our LCOEs with lease areas of one particular developer. The reason that we modeled a smaller first Tranche is that subsequent tranches would likely be lower cost as described below.

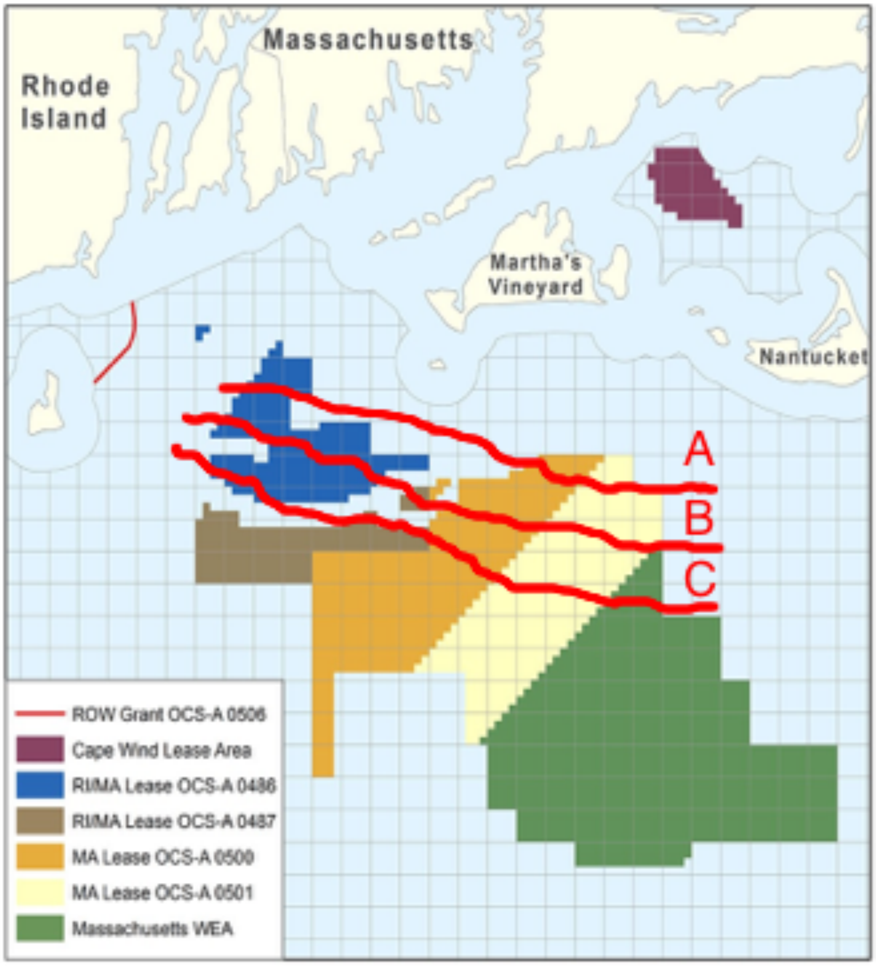


Figure 3. One example of possible Trances A, B and C, shown in red.

Wind speeds and energy production

Analysis of wind speeds for the three indicative tranches were purchased from a vendor, Natural Power, and were based on a combination of reanalysis data and the weather research and forecasting model (WRF). Because wind speeds are fairly uniform over the entire area including RIMA and the MA WEAs, we were able to capture the site variability with just two point measurements. The hourly wind speeds at 100m height above sea level was used in a model of wind farm layout with spacing 10D x 10D and thus power density of 2.97 MW/km^2, to estimate wake losses. This model results in a net annual energy production (AEP), after subtracting wake loss, and equivalently, a net capacity factor (CF), with "net" in both cases referring to the sum of electrical output from all wind turbines, having subtracted wake loss but not electrical cable losses.[52] AEP and CF were based on the power curve for the MHI Vestas 8 MW turbine.[53] The CF and thus AEP is likely to increase over time for the WEAs of this study, as the blade on the MHI Vestas is a bit undersized for this wind regime.[54] A similar issue has been identified for this turbine-blade combination in European projects. Thus as either European market growth continues, or if a sufficiently-large market emerges in the US Northeast, we may see larger rotors developed to operate more efficiently in these environments.[55] Due to such factors, we used the expert elicitation to check our CF, even though this is a number we derived ourselves (experts gave similar numbers, but which CF increasing through time).

Transmission analysis

Like the wind speed analysis, we did our own analysis of transmission cost rather than relying on costs from the expert elicitation. There are several possible transmission solutions for each project, and for the set of projects if they decided on a joint transmission solution. We were advised that our expert interviewees could not give estimates for comparable transmission solutions at this point. Therefore, we carried out an analysis of the simplest transmission solution, a single AC line from each tranche to shore. This was based on models of our third author (Ozkan) who is an expert on subsea transmission. To fit within existing on-shore points of interconnection (POI) and to minimize need for upgrades to existing lines, two points on the high voltage system were selected, Oak Street and Brayton Point.

The other option would be a common 2,000 MW HVDC line from the three leased areas to two interconnection points on shore. An HVDC system would likely provide system

[52] Niranjan S. Ghaisas, and Cristina L. Archer (2015). Geometry-based models for studying the effects of wind farm layout, Journal of Atmospheric and Oceanic Technology. doi: 10.1175/JTECH-D-14-00199.1
[53] SIOW used the published graph of the power curve of the MHI Vestas 8.0-164, and fitted a polynomial to it, for use in these calculations.
[54] Also, layout improvements can be made to the economics by dense outer perimeters and possibly over-planting can further reduce the LCOE
[55] The desirability of a larger rotor on the 8 MW machine even in Europe was identified by Adrian Fox, personal communication.

benefits (power could be moved from one connection point to another on-shore, providing a "system benefit" to the existing on-land transmission system). For simplicity, we use only cost for a route requiring no cooperation among developers, although this may not be the lowest cost if all factors are considered. Because of new offshore wind transmission products already being introduced, we included a cost reduction factor on transmission through the 2020-30 time period.[56] As noted earlier along with the elicited wind farm costs, transmission analysis cost inputs can be found in Appendix A.

Market and policy assumptions

We made assumptions regarding the offshore wind market in the northeast and other relevant federal polices, in calculating LCOE's across the tranches. Among Maryland, New Jersey, New York, and Rhode Island, there is a total of 3,750 MW either in enacted legislation or under discussion. We conservatively assumed that only half of this would be built (outside Massachusetts) between Tranches A and C. That is, in addition to the 2,000 MW of offshore wind development in Massachusetts over 2020-30, another 1,875 MW are built in the Northeast and Mid-Atlantic region during the same period. The regional 1,875 and Massachusetts 2,000 MW are added to calculate learning on Tranches B and C.

We assumed no federal production tax credit, no federal investment tax credit, no REC sales, and no state subsidies. The tax and depreciation rates assumed are typical for privately-owned productive assets, shown in Appendix A, Table A2.

Supply chain and vessel assumptions

Because we were relying on the knowledge of industry experts who are currently examining the logistics for Massachusetts offshore wind farms, we did not impose assumptions regarding localization of supply chain, deployment approach, or vessels.

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[56] http://www.windpoweroffshore.com/article/1338456/analysis-siemens-radical-substation-plan

Rather, in follow up interviews we obtained the assumptions used by our expert informants in these categories, which are described below.

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Tranche A: Turbine systems are manufactured in Europe and stored in a local buffer port. Foundations and onshore substations are manufactured in the US, according to two of the three companies. The assumed extra cost from shipping and plus an extra handling step were not seen as a significant cost adder to the CapEx, especially given fluctuations in exchange rates and commodity prices.

Regarding vessels, all three developers agreed that there would be no US flagged heavy lift vessels capable of turbine installation for Tranche A. All assumed a feeder barge arrangement, that is, using a combination of US vessels loading in port, and European specialized installation vessels that only operate offshore." Cable installation vessels were also assumed to be European.

Tranches B & C: All major components manufactured in the US if there is sufficient quantity and certainty of Massachusetts plus regional wind power market. The experts also assumed that by Tranche B, there will be US flagged vessels, again assuming the development of a US market.[57]

Results: Massachusetts LCOEs

This section reports the anticipated LCOEs for the three tranche areas – with and without the further impact of learning effects as the U.S. market matures. LCOEs are presented both with and without transmission included.

Overall, global cost reductions in OSW technology and U.S. market maturation will lower the cost of OSW installations resulting in lower LCOE for Massachusetts OSW

[57] Development of U.S.-flagged vessels was reported as being less dependent on certainty of volume than is local supply chain, as U.S.-flagged vessels could potentially support the future European and Asian markets in addition to a U.S. market.

projects, compared to previous project LCOE's in the New England area. Continuation of these trends, a commitment to a pipeline, and larger project sizes, in combination, lead to reductions in cost over time as seen in Table 4. The inputs to LCOE analyses, showing reductions in input costs, can be seen in Appendix A. Table 4 below provides those LCOE's that consider the economies of a full 2000 MW build-out.

Table 4. Baseline LCOE assuming 2,000 MW Massachusetts pipeline of projects but no learning effects.

	Tranche A 400MW COD 2023	**Tranche B 800MW COD 2026**	**Tranche C 800MW COD 2029**
LCOE without transmission (2016 ¢/kWh)	12.4¢	$10.5¢	$8.7¢
LCOE with transmission (2016 ¢/kWh)	16.2¢	13.5¢	11.5¢

Estimating the impact of learning on Massachusetts LCOE's

To calculate the learning effects from any further market development in the U.S. between FC in 2020 and 2030, the study team applied a 5% learning curve per doubling of capacity based on a review of top-down statistical analyses of offshore wind learning curves, conducted in 2013 by the Brattle Group.[58] The Brattle Group assessment discovered LCOE cost reductions ranging between 3% and 10% per doubling of capacity and considered some of the seemingly-contradictory factors that have been driving up offshore wind costs over the past few years to be temporary.[59] These learning rates were also found to be consistent with those historically observed for onshore wind. Brattle interpreted 3% learning as a slow learning rate and 10% as high and suggested using a 5% intermediate value. In this study, we applied this intermediate learning rate of 5% per doubling of capacity only to its estimates for support structure, installation and O&M costs.[60] We did not apply the learning rate to the wind turbine system (rotor-nacelle

[58] Weiss, Jurgen, M. Sarro and M. Berkman (2013). "A Learning Investment-based Analysis of the Economic Potential for Offshore Wind: The case of the United States," prepared for the Center for American Progress, the U.S. Offshore Wind Collaborative, the Clean Energy States Alliance and the Sierra Club.

[59] Weiss et al, p. 23.

[60] Two experts in post-interviews plus one peer reviewer, all of whom were especially knowledgeable of European cost trends, have suggested that our use of a 5% learning rate is too low. If that is correct and if

assembly and tower) because those are manufactured by OEMs (for many customers), so the learning rate is already included in their price quotations.

Table 5. LCOE assuming 2,000 MW Massachusetts pipeline of projects and learning effects.

	Tranche A 400MW COD 2023	**Tranche B 800MW COD 2026**	**Tranche C 800MW COD 2029**
LCOE without transmission (2016 ¢/kWh)	12.4¢	9.8¢	7.9¢
LCOE with transmission (2016 ¢/kWh)	16.2¢	12.8¢	10.8¢

Impact of market visibility on LCOE

In SIOW's offshore wind cost reduction analyses for New York, we determined that market visibility – a commitment to a certain volume of OSW (a pipeline of projects) over a defined period of time – reduces cost of offshore wind energy by these mechanisms: 1) creating competition by interesting additional entrants (suppliers, vendors, etc.) to the market; and 2) attracting over time investors with a lower hurdle rate, as infrastructure and other investors enter the space, replacing "pioneer" investors with high expected rates of return.

The study team learned from experts interviewed for the New York study that the competition created by a visible pipeline of projects, versus the market entrants likely for a "one-off" project only, could likely reduce CapEx, maintenance and insurance costs from 10 – 20%. Also by generating repeated investment by equity investors with sector knowledge and experience, as opposed to pioneer investors, WACC could be lowered by reducing the cost of equity by as much as 3%.[61] Market visibility for offshore wind can be achieved by government policy that commits to the build-out of a sequence of projects, as opposed to a policy for one single project. Table 6 compares the LCOE for

our volume assumptions are correct, then the LCOE prices we estimate for Tranche B and C should be lower than we show in this report.

[61] McClellan (2015). New York Offshore Wind Cost Reduction Study, p 38.

Tranches A, B, and C (given a visible pipeline of projects) versus LCOE's for other offshore wind projects that had been bid and contracted without market visibility.

Table 6. Impact of scale: Comparison of New England LCOEs

Project	Anticipated Financial close (year)	Project size (MW)	OSW Market Visibility in New England (MW)	LCOE (¢/kWh)
MA project proposed	2014[a]	468	400	24¢[b]
RI project under construction	2015	30	30	30¢[c]
Tranche A (this study)	2020	400	2,000	16.2¢
Tranche B (this study)	2023	800	2,000	12.8 ¢
Tranche C (this study)	2027	800	2,000	10.8¢

[a] Proposed Cape Wind project has not yet reached financial close.
[b] Calculated from published National Grid PPA terms reported in Musial and Ram, converted to LCOE.
[c] Calculated from published PPA terms reported in Musial and Ram, converted to LCOE.

Table 6 illustrates clearly the effects we are discussing. The prior one-off projects in the New England region have been much higher cost than would be projects as part of a systematic policy-driven pipeline with market visibility. Again, the reasons for the lower prices starting 2020 in Table 6 are: Technology improvements coming from Europe, market visibility of a Massachusetts commitment to 2,000 MW in addition to a similar quantity in the northeast region, and, for Tranches B and C, learning effects, and localization of supply chain.

Benchmarking our results

The LCOE's calculated from the expert inputs are less than prior US projects, as shown in Table 6. Given what is happening in the global industry, this should be expected. However, the U.S. has no offshore wind farms in its waters, no mature supply chain nor dedicated infrastructure similar to that in Europe. How do our estimated LCOE's for Massachusetts's projects in the modeled tranches compare to what is happening in the global market? We benchmarked our findings against two different sources of data: 1) the latest European tenders (illustrated in Figure 1 above); and 2) ranges of LCOE's anticipated between 2020-30 in the UK, as projected by BVG Associates for Statkraft UK.

In Figure 4, we have plotted the estimates for the three Massachusetts tranches, assuming learning and market visibility against the UK Cost Reduction Goals, the LCOE averages of projects evaluated for the UK Cost Reduction Monitoring Framework (operational 2010-2015), and the latest European tenders (operational 2019 and 2020).

The Massachusetts LCOE's (blue circles in Figure 4) follow the downward trajectory as the LCOE averages of projects evaluated for the CRMF, and the UK cost reduction targets. Moreover, as can be seen, the Massachusetts LCOE's can reach prices of the 2019-20 operating European projects (triangles), albeit not until 2023. US projects becoming operational in 2023 still do not reach the level of the Horns Rev III project – Europe's lowest bid (mainly because Tranche A is the first US project, but also because Horns Rev III is in shallower water and closer to shore[62] than the MA WEA).

In short, this benchmarking suggests that Massachusetts projects would follow the same declining cost trajectory as has been seen over time in Europe.

[62] Energinet.dk, 2013, "Horns Rev 3: Technical Project Description for the large-scale offshore wind farm (400 MW) at Horns Rev 3." Dokument nr. 106078/13, sag 12/827 – Dated 030513

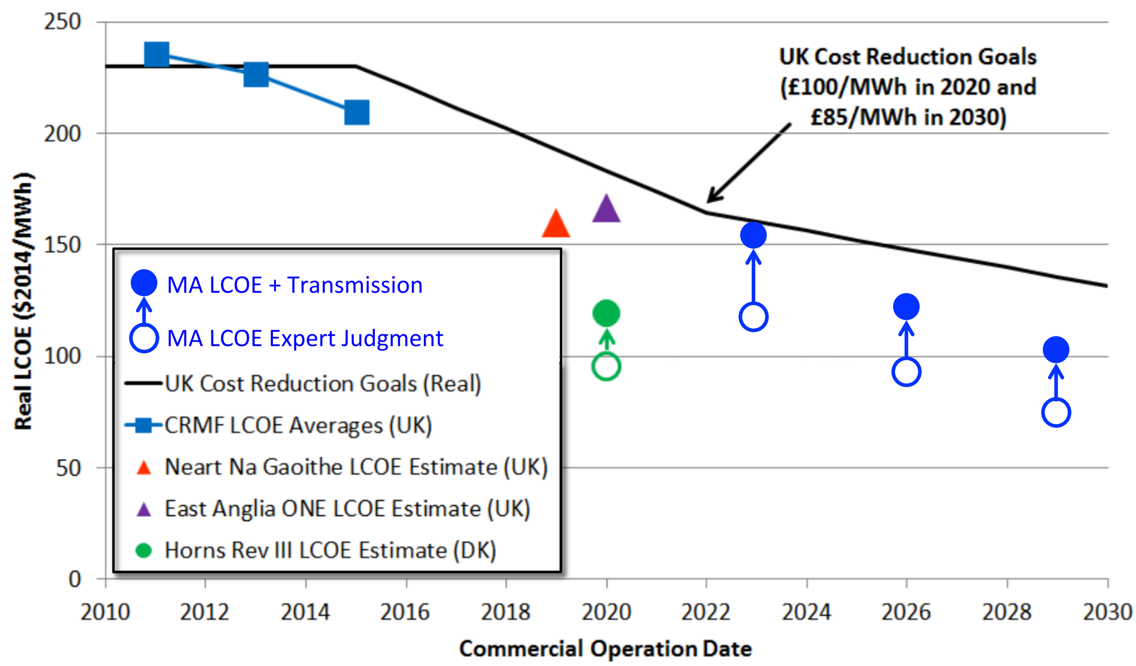

Figure 4. This report's estimated Massachusetts LCOEs (blue circles) benchmarked against European LCOEs. (Original figure from NREL report, referenced in this report's prior Figure 1.)[63]

As a second benchmark, the study team compared our Massachusetts findings against the LCOE ranges projected by BVG Associates.[64] Those ranges in are shown in blue bars in Figure 5. SIOW's estimates for Massachusetts are plotted in orange circles. Figure 5 shows that at the beginning of the U.S. market (Tranche A with financial close in 2020), LCOE's are at the high end of the BVG Associates projected LCOE range. By 2030, however, we find the latter stage Massachusetts projects are reaching the mid-range of the projected European projects.

[63] Massachusetts project estimates appear on Figure 4 after they have been converted into nominal LCOE's $2014 to better match the Real LCOEs $2014 that NREL placed on the original figure. This results in the LCOEs on this graph being slightly different from our $2016 nominal figures reported elsewhere in this document. Also, as noted, there are uncertainties associated in comparing PPA and LCOE prices because of differences in project scope, market structure, and site characteristics.
[64] BVG Associates, 2015, "Offshore Wind: Delivering More for Less," an independent study commissioned by Statkraft. Technical Annex, p. 12.

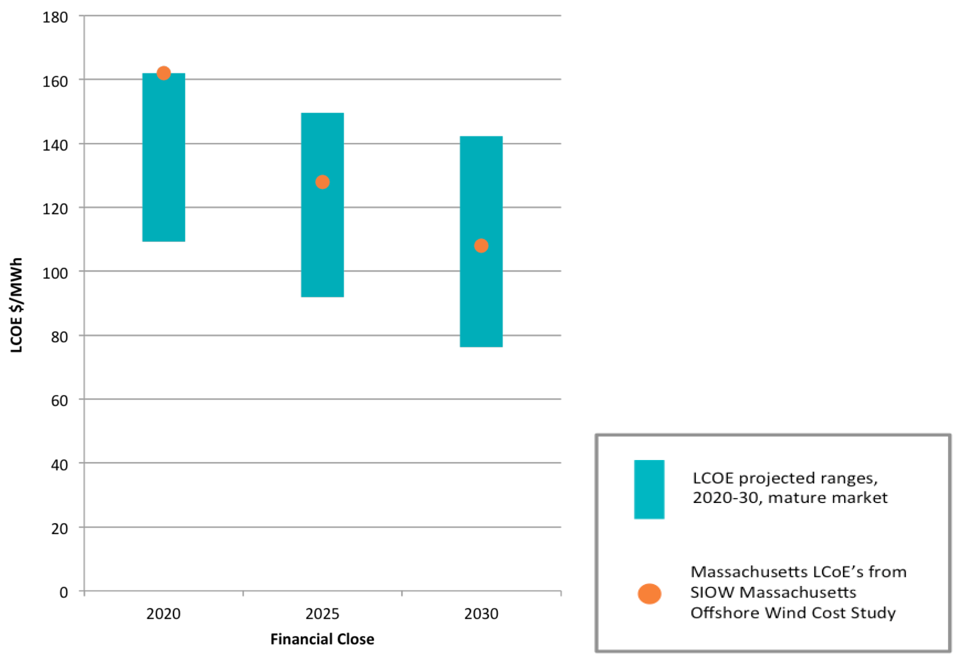

Figure 5. Estimated Massachusetts LCOEs, Benchmarked against Projected LCOE (data from BVG Associates).

The benchmark against the BVG projections, like the check against the data summarized by NREL, show that our calculations for Massachusetts are consistent with trends in the industry. As noted, in addition to assuming a continuing market in Europe, these findings are not automatic. They occur only with market visibility, that is, a firm commitment by Massachusetts plus other activity in the region. Experts comments also explained that they assumed European-based supply chain and vessels in Tranche A, transitioning to local supply chain and U.S.-built ships in Tranches B and C. Along with learning, these are the reasons Tranches B and C show lower cost.

Conclusion

To reliably project the cost of a rapidly-changing technology in the future, for example, a project that would be built and commissioned about six years ahead of the analysis, we developed an expert elicitation method. We solicited confidential expert estimates of each of the major costs of developing, building, financing, and operating an offshore wind tranche, then arrived at a weighted mean of those estimates and used the mean values as input to the public-domain CREST tool to produce the LCOE for each Tranche. We added the cost of a simple transmission solution, without eliciting data for that component.

We found that our projected costs are consistent with two published benchmarks, and show a trend line of declining cost over the 2020-2030 period due to the factors cited. The LCOE for the first tranche begins with an electricity price above today's market. Costs continue to decline in subsequent builds, so that by the last tranche of a 2,000 MW pipeline, costs are similar to today's market cost, and at that point the technology presumably could continue to compete on its own without any continuing legislation. Dividing the decade into three tranches, LCOE costs with learning effects on installation and operations and maintenance were 12¢, 9.8¢ and 7.8¢ per kWh, or including transmission were 16.2¢, 12.8¢ and 10.8¢ per kWh. Again, these are calculated LCOE, which does not consider any Federal tax credit, state RECs or potential carbon fees, any of which would lower the actual price below our LCOE projection.

The cost reductions are driven by state policy committing to build a sequence, of projects as well as "learning effects," as develops skilled workfore grows locally as the Massachusetts market develops..

The forecasts here are based upon the expansion of existing technologies. Wind technology, however, is still young. The knowledge base and creativity in Massachusetts higher education and R&D sectors could well have a role to play in innovating and creating a new generation of offshore wind turbines.

Appendix A: Input data to calculate LCOE

Table A1 contains all input values used in the cost analysis. As described in the main text, the values in this table were developed through expert elicitation with offshore wind commercial experts. The below are mean values from the group, sometimes .ing a weighted mean based on our judgment about knowledge of the expert source of each particular cost. The values below are the inputs to the LCOE calculations.

Table A1. Inputs used in LCOE calculations[a]

Input category	Units	Tranche A	Tranche B	Tranche C
CAPEX				
Turbine	$/kW	$1,615	$1,424	$1,263
Support Structure	$/kW	$681	$604	$527
Installation (turbine and support structure)	$/kW	$369	$349	$324
Within Farm Array Cable	$/kW	$176	$167	$154
Development and permitting	$/kW	$191	$171	$144
Financing, legal and other (including developer's fee)	$/kW	$268	$240	$201
Subtotal Generation cost	$/kW	$3,299	$2,956	$2,612
Transmission Cost	$/kW	$1,318	$1,054	$923
Total Cost	**$/kW**	**$4,617**	**$4,011**	**$3,535**
Contingency	%	10	7	5
Total Cost Inc. Contingency	**$/kW**	**$5,079**	**$4,292**	**$3,712**
OpEx[b]				
Fixed O&M Expense, Yr. 1	$/kW-yr	$95.45	$83.60	$78.68
Contingency	%	10	7	5
Fix O&M Expense, Yr.1 inc. Contingency	$/kW-yr	105	89.45	82.61
Decommissioning[c]	$/kW	$20	$20	$20
Offshore Land Lease	$/yr	$146,250	$146,250	$146,250
WACC[d]				
Construction Financing				

Construction period	Mos.	24	24	24
Interest rate	%	8.1	7.5	7
Permanent Financing[e]				
Percent debt	%	65	73	76
Debt term	Years	15	15	18
Interest rate on debt term	%	6.00	6.00	6.00
Lender's fee (% of total borrowing)	%	2.50	2.50	2.50
Req. minimum annual DSCR		1.2	1.2	1.2
Req. average DSCR		1.45	1.45	1.45
% equity		35	28	24.5
Target after tax equity IRR	%	8	8	8
AEP				
Turbine rating	MW	8	8	8
Downwind spacing	Diameter	10	10	10
Crosswind spacing	Diameter	10	10	10
NCF	%	45.3	46.0	47.2
Project useful life	Years	25	25	25

[a] Cost inputs before any learning impact applied.

[b] One experienced expert group told us their OpEx estimate represented a16% reduction in cost for OpEx compared to the initial SIOW estimate. This assumes that the OpEx figure has been calculated across the lifetime of the project (25yrs). They expected that the vast majority of lessons learnt from Europe can be applied to the US/Massachusetts projects, given that they are primarily logistic and experience/knowledge based. Technical innovations such as helicopter OpEx will also be directly applicable to projects in the US/Massachusetts market.

[c] Decommissioning fee includes resale of salvaged materials, especially the subsea support structure.

[d] WACC is in the 5-8.1% range, (8.1% for construction, 5.5% for operation) based on [55-76] % leveraging, 35% federal tax rate, and 8.5% state tax rate, see Table A2.

[e] To some readers, the finance rates and debt-to-equity ratio may seem aggressive. It should be remembered that among the three developers who hold leases in the federally-designated RIMA AMI and MA WEA, two are owned by capital companies backing the project, and the third has been known to use its balance sheet to finance projects. This explains the low cost of capital. We are not saying every offshore wind project would achieve these terms, rather that the terms assumed reflect their capabilities.

Table A2. Tax and depreciation assumptions

State tax rate	8.5%
Federal tax rate	35 %
Effective tax rate	40.5%
Generation equipment	96% of CapEx is depreciated by 5-yr MACRS, 2% by 15-yr MACRS and 2% by 20 yr SL (straight line)
BOS	75% of CapEx by 5-yr MACRS, 25% by 15-yr SL
Interconnection (transmission)	100% 15-yr MACRS
Development Costs/Fees	80% 5-yr MACRS, 5% 15yr-SL, 5% 20 yr SL and 10% is non depreciable
Reserves and Financing Costs	50% 20yr-SL and 50% Non-depreciable

Table A3. Cost inputs for Transmission – AC Radials[a]

Tranche A 400MW FC 2020, COD 2023	
Electric Service Platform	$100,000,000
AC Radial	$344,711,070
Tranche A Total	$444,711,070
Tranche A ($/kW)	$1,112
Distances	40 miles offshore, 0.2 miles onshore
Tranche B 800MW FC 2023, COD 2026	
Electric Service Platform	$200,000,000
AC Radial	$747,127,787
Tranche B Total	$947,127,787
Tranche B ($/kW)	$1,184
Distances	38 miles offshore, 4 miles onshore
Tranche C 800MW FC 2027, COD 2029	
Electric Service Platform	$200,000,000
AC Radial	$905,971,522
Tranche C Total	$1,105,971,522
Tranche C ($/kW)	$1,382
Distances	48 miles offshore, 4 miles onshore

[a] Cost inputs before any learning impact or cost reductions applied.

Appendix B: Expert Elicitation

Selecting particularly knowledgeable individuals, picked for their expertise, and interviewing them is called "Expert elicitation". This is quite different from survey research, where many people are picked at random and asked about their preferences, or about topics on which they are not necessarily knowledgeable experts. Here, expert elicitation methods were used to determine the inputs for the cost modeling. As described by Morgan, expert elicitation proceeds by seeking carefully reasoned judgments from experts about quantities or processes in their domains of expertise, often uncertain and thus in the form of subjective probability distributions. This process has a well-developed methodology.[65] In some fields, expert elicitation may involve interviewing 10-30 experts, weighting them equally and producing mean, mode and standard deviations of responses. We selected by company rather than by individual, with each company typically having a team from 4 to 20 individuals working on US markets—calculating costs for projects, evaluating subcontractors, and judging market viability in the electricity markets where the power would be sold. We contacted someone in or connected to the cost evaluation group within the company. The group settled internal discrepancies and disagreements and gave us the company's single number for reach variable. Thus we were left with four "company consensus" numbers for each quantity we sought (below), or in some cases fewer than four because we discouraged but allowed not responding. Below we describe how a single number was derived from each set of responses.

For typical expert elicitation, Morgan recommends starting by asking the experts for the highest and lowest value possible, for each estimate being elicited, only after that asking them for their best judgment.[66] However, here the numbers were already developed by the organizations and in most cases had already been subject to an internal review

[65] Morgan, M. Granger (1990). Uncertainty: A Guide to Dealing with Uncertainty in Quantitative and Risk and Policy Analysis. Cambridge University Press, Cambridge, MA.
[66] M. Granger Morgan, 2014, Use (and abuse) of expert elicitation in support of decision making for public policy." *Proceedings of the National Academy of Sciences*, vol. 111 no. 20, 7176–7184, doi: 10.1073/pnas.1319946111

process; also our request was an imposition on time, and we were asking for 27 numbers for each tranche, times 3 tranches, a total of 81. To get participation, we had to make the process as rapid as possible, which precluded detailed questions for each quantity. For the same reasons of respondent expediency, we provided a number based on our earlier New York Offshore Wind Cost Reduction Study, allowing them to "agree" or "do not object" if they felt our pre-provided number was close to their judgment. The other choice was to "disagree," in which case they had to offer a replacement number. The pre-provided numbers were from earlier studies and therefore we expected they should be frequently corrected by newly collected data.

Providing a suggested number to experts is not recommended in expert elicitation, as it tends to bias the respondent toward agreeing with the provided number or values closer to that.[67] In this domain, for most experts in these companies, the costs of components, installation, and eventually, the cost of electricity are numbers that they live and breathe. They have measured wind and water depth, reviewed prior projects, obtained quotations, and run a program to calculate LCOE many times. Most of the numbers to which they simply "agreed" were to standard terms, such as contractor contingency percentage and loan term, and to known rates and physical factors that can be measured such as lease rental cost, turbine size, and capacity factor in this region. For the less standard and more important cost estimates, we observed that in most cases companies corrected our initial suggestion, increasing our confidence that our provision of default numbers did not bias the results. We also observe that when a company gave "no objection" to our numbers, it was in area that we observed the company had less experience.

For the composite numbers reported below and used in our LCOE calculation, all the elicited numbers are used, although they were not necessarily equally weighted. In developing a single number, we followed these rules, in order:

1. If all of the answers, from high to low of responses were within 10% of one another, we present the mean.

[67] Morgan, 2014, page 20, our provided value could have an "anchoring" effect.

2. Otherwise, a weighted average is taken, with the following leading us to assign more weight:
    - Estimates with more credible back-up references;
    - An estimate from a company that would appear to have more knowledge in the particular category. For example, if they had already built a wind farm in similar conditions, or if they had quotes from (or themselves were) an appropriate turbine vendor.
    - After above, if one company only said that they "do not object", their "number" (actually in this case our suggested number) get much less weight than others who provided a unique calculation.

A brief summary of the above is that we use a mean, but when dispersion is > 10%, we consider a self-admission, company experience, or our judgment, to give less weight to an estimate if the expert has less experience or less certainty. Note also that all values given are used in the weighted mean, so that there is no way for any firm to identify the value given by another firm.

Due to the complexity of the process that our experts followed, and their differing assumptions, we provided detailed instruction on the questions about what each meant, and in three cases, followed up with a phone call to insure they had answered the questions as asked. As one example, contrary to instructions, at least two sources assumed market visibility, that is, their costs included a commitment to build all 2,000 MW. To avoid counting market visibility twice, we assumed that all the data on component costs already include market visibility; therefore, to calculate cost with and without, we added to the elicited cost to develop the input for LCOE without market visibility.

As a check on the veracity of the expert informants, one might ask if there is another type of bias in that one source of estimates are developers who eventually would like to make bids on electricity in Massachusetts. We have three types of check on this effect, none perfect. The first check is that we benchmark out numbers against other studies and industry sources who are not involved in Massachusetts's bidding. The second check is to consider the motivations and risks of the developers manipulating the prices. Since a bill would come up before the Massachusetts legislature before the developers could bid, if the developers were gaming this, they might suggest that prices would be lower, to encourage passage of the bill. The risk of that strategy would be that, if they accomplished this, the bill would be passed with a price cap calibrated to this price (price caps have been included in OSW legislation, in Maryland), which would then either cut into their profits and/or make it impossible for them to successfully bid on the project. This "double-bind" situation would seem to force them into a band of safety, where they do not bid lower than they can actually achieve, nor higher. The third factor is that, for 3 of our 4 sources, we discussed their numbers with the people in the company who produced them, and often asked them to justify individual numbers; we judged their answers plausible and often based on specific knowledge they have from several other projects, from bids, and from other experience they could relate to us. The combination of these three checks, more than any one alone, leads us to conclude that the results are valid and are unlikely to have bias due to their commercial interest, or other biases.

In addition to the above potential method biases, there is a potential commercial bias in collecting inputs from experts whose firms are potential bidders in this market. Because they would benefit from a law obligating the purchase of offshore wind energy they may want to make the costs appear lower then they are. The countervailing risk to these experts is that policymakers could legislate the LCOE numbers resulting from their inputs as a ceiling price for bids. The European use of strike prices matched to cost reduction targets and to "what the industry says it can achieve" indeed illustrates this possibility. We judge the risk of providing low estimates to be a much greater risk to expert informants' firms, therefore we do not believe commercial bias has led to unrealistically low inputs or resulting LCOE prices.