VINEYARD WIND

A Copenhagen Infrastructure Partners company

March 13, 2017

Via email to: marfp83C@gmail.com

To: The Massachusetts Department of Energy Resources
The Massachusetts Office of the Attorney General
Fitchburg Gas & Electric Light Company d/b/a Unitil ("Unitil")
Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid
NSTAR Electric Company and Western Massachusetts Electric Company d/b/a Eversource

Re: Request for Stakeholder Comments Concerning Solicitation for Long-Term Contracts for Offshore Wind Energy

To Whom It May Concern:

Vineyard Wind, LLC ("Vineyard Wind") appreciates the opportunity to submit these comments concerning the development of a request for proposals ("RFP") to implement the requirements of Section 83C of Chapter 169 of the Acts of 2008, as amended by Chapter 188 of the Acts of 2016, *An Act to Promote Energy Diversity* ("the Act"). Vineyard Wind is a project development company that acquired a Massachusetts offshore wind lease area from the federal government through the competitive auction process in 2015, and is therefore qualified to participate in the upcoming Massachusetts wind energy solicitation. Vineyard Wind is a portfolio company of funds managed by Copenhagen Infrastructure Partners ("CIP"). CIP has currently more than $3.5 billion assets under management a substantial track record of developing large scale renewable energy projects around the world, including offshore wind projects in Europe.

At the outset, Vineyard Wind commends the Commonwealth of Massachusetts on its bold leadership in launching a commercial-scale offshore wind industry in the United States by seeking cost-effective long-term contracts for 1,600 megawatts of offshore wind energy in accordance with the requirements of the Act. Massachusetts has in front of it a unique opportunity to procure offshore wind energy in a manner that will: (1) ensure that these long-term contracts deliver the best possible value to Massachusetts ratepayers; (2) facilitate the successful completion of large-scale renewable energy projects to help the Commonwealth achieve its legally required greenhouse gas ("GHG") reductions; and (3) help Massachusetts capitalize on the significant economic development opportunity these projects present. This is an exciting moment for the Commonwealth and for the emerging U.S. offshore wind industry, and Vineyard Wind is committed to working collaboratively with the Commonwealth to make the upcoming offshore wind energy solicitation process a success.

Because the Act requires the first solicitation to take place no later than June 30, 2017, the Commonwealth (through the Department of Energy Resources, "DOER"), the electric distribution companies ("EDCs") and the Attorney General's Office have a short amount of time to make critical decisions that will not only govern the first solicitation, but which will also have ramifications for the long-term success of the Commonwealth's offshore wind procurement efforts. This will be the first large-scale competitive solicitation for offshore wind energy in the United States, and it represents a significant and long-term commitment to renewable energy by Massachusetts' ratepayers. In that spirit, Vineyard Wind offers the following overarching comments for consideration by the DOER, the EDCs and the Attorney General's Office in addition to our below responses to the specific questions that were asked of stakeholders.

1. Focus on Achieving Lowest Cost Projects

Vineyard Wind respectfully submits that the primary goal of this first solicitation should be to procure the lowest-cost contract that meets all of the requirements of the Act. This is the best way to demonstrate that the process can be successfully replicated for the entire 1600 megawatt ("MW") authorization. To accomplish this, a simple and straightforward bidding and evaluation process should be the goal. A participating developer should be incentivized to optimize all elements of project delivery (minimizing lifecycle costs for constructing, operating and financing a project) by being responsible for the complete end-to-end delivery of the project. This is the best way to ensure that ratepayers of the Commonwealth will be offered the lowest possible costs for delivery of offshore wind under the first solicitation, and will build confidence that contracts can be delivered cost-effectively in each subsequent solicitation.

2. Procure 400 MW in the First Solicitation and in Each of the Next Three Solicitations

Vineyard Wind believes the best way to achieve the goal of a lowest possible cost for the first project is through creation of a process which seeks to award a single contract of 400 MW of offshore wind energy generation and associated transmission costs. This format for the first solicitation is not only the most obvious reading of the statute and what it requires, but will also maximize the chances of the first solicitation resulting in the selection of a project that will create a successful first example to replicate.

Specifically, the DOER and EDCs should establish a schedule now for the entire 1600 MW solicitation in which four individual 400 MW projects would be solicited over a four-year period (4 x 400 MW in 4 years). This will have several positive outcomes for Massachusetts:

- It will drive the total cost of the 1600 MW of contracts to the lowest possible cost by maximizing the impact of the built-in price "ratchet" that requires every subsequent contract to come in at a lower price than the one prior;

- It will provide a strong incentive for project developers to make forward-looking investments in physical surveys, analysis and planning thus, and enable learning and innovation to be applied in further competitive solicitations;
- It will send a strong signal to all supply chain partners that there will be predictable market development, thus increasing supply chain competition which would lower overall project costs and consequently costs for ratepayers, while also allowing Massachusetts and U.S. based supply chain partners (including manufacturers and the ports infrastructure) to grow into the offshore wind market at a manageable pace;
- Multiple and frequent solicitations will avoid potential “boom-and-bust” or “winner-takes-all” scenarios, in which one participant dominates the market. A 400 MW project size fits well with the existing port infrastructure in Massachusetts, in particular for the capacity of the New Bedford Marine Commerce Terminal.

This first-of-its-kind procurement presents a unique opportunity to establish a new industry that, over time, could spur significant economic development and job creation in the Commonwealth—but only if we “get it right”. Massachusetts should be wary of launching into construction of extremely large projects straight out of the gate, which could prove challenging to execute and risk setbacks to the nascent Massachusetts industry. As shown in further detail in the attached Appendix A, an 800 MW project **would be larger than any European offshore wind project that is currently in operation or has commenced offshore construction, and only one project with a size of 800 MW or above has yet achieved financial close globally**. See Figure 1, Appendix A. In fact, the fifteen largest operating wind farms to date have an installed capacity between 400 and 630 MW.

Furthermore, the experience in substantially more mature European markets is that over the last five years the average project sizes have generally been in a range of between 350-400 MW.

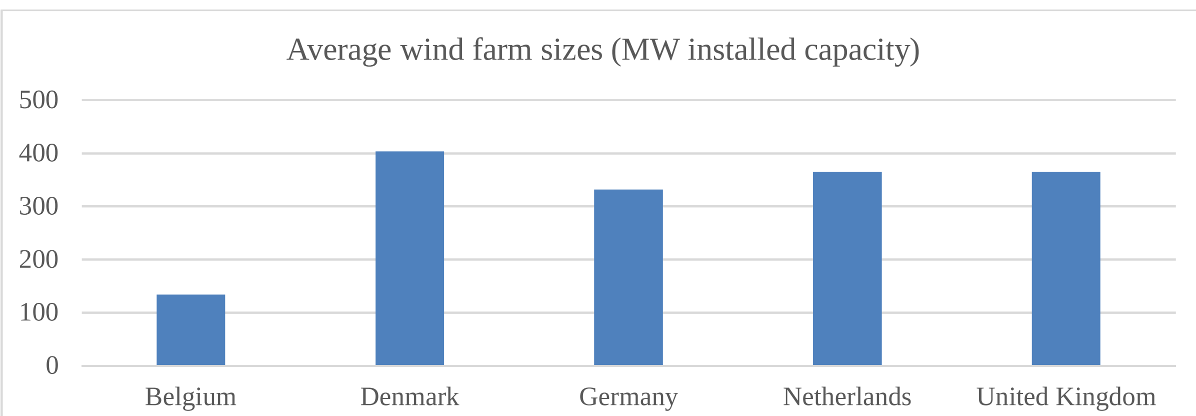

Figure 1 *– Average wind farm sizes in the European markets. Analysis Includes the 34 largest offshore wind farms with commissioning date from 2012 onwards. Depicts installed capacity in MW. Includes projects in operation or under offshore construction.*

Massachusetts' best chance to successfully kick-start a new U.S. industry is to focus on a project size of 400 MW, consistent with the majority of the projects that have been developed globally in the last five years (and for the reasons described above concerning price and fostering competition in the supply chain). And because the Act plainly does not permit proposals for less than 400 MW (as discussed in greater detail below, such an outcome is not permitted by the language of the Act, nor is it advisable for a host of public policy reasons), 400 MW is a natural starting point for the first solicitation.

Vineyard Wind also strongly discourages the DOER and the EDCs from structuring the solicitation to allow for a range of proposed project sizes. Vineyard Wind believes that allowing a range will likely result in bids for the maximum MW available, as developers would not want to be on the losing end of a "winner takes all" scenario. Therefore, the process would, in effect, be opting for a large project size and all the risks and challenges that come with it, as described above. In addition to all of the reasons above about why the state should be wary of taking on 700-800 MW projects, allowing differing project sizes will also make transparent, "apples to apples" bid evaluations virtually impossible.

3. Keep Transmission Requirements Simple

In addition, the EDCs and DOER should seek to reduce complexity and risk to all parties by approaching the questions concerning offshore wind transmission in a manner that is as transparent and as straightforward as possible. The best way to drive bid prices lower is to place the burden on developers to deliver an "all-in" cost that incentivizes avoidance and mitigation of development risks as much as possible, including any transmission cost overruns. This "end to end" project delivery model puts the risks on the developer, not the ratepayer.[1]

In addition, the RFP should not include or permit any "alternative approaches" to transmission such as delivery to a common offshore delivery point (as is contemplated by question 6 in the request for stakeholder comments)—at least not in this first solicitation. While a well-designed proposal to create offshore transmission infrastructure would be conceptually worthy of discussion (if it could be structured to avoid the numerous potential risks to ratepayers and to developers), there is nothing resembling a fully formed proposal of that type at this time. Particularly given certain prior experiences in Europe that counsel for caution in the design and execution of such a scheme, this type of proposal would need to undergo a thorough evaluation by policymakers and regulators. Vineyard Wind does not believe there is anywhere near enough time for such a process prior to the statutory deadline of June 30. Adding this concept to the first RFP at this late date brings substantial risks for delay, introduces complexity that will drive up

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[1] It is important to remember the context for the development of offshore wind resources and associated transmission is very different than that for procurement of Clean Energy Generation under Section 83D of the Act. Unlike the multi-party generation plus transmission model at issue in the Section 83D procurement, a single commitment for the delivery of offshore wind to the grid (including the transmission needed for delivery) is the easiest and most cost-effective model to implement in this procurement. The RFP for offshore wind should simply require the bidders to deliver their energy to the grid for a specified price and let the developer bear the risks of achieving that outcome.

costs rather than reduce them[2], and could ultimately undermine the Commonwealth's ability to deliver a cost-effective and successful first project. Vineyard Wind therefore strongly recommends that the RFP focus on a simple construct for transmission that puts the obligations to deliver energy and associated transmission, and to bear cost overruns if any, on the bidder.

4. Conclusion

Thank you for the opportunity to respond to this request for information. Vineyard Wind's specific responses to questions are presented below, and we look forward to the next stage of the RFP process.

Respectfully submitted,

Erich Stephens
Chief Executive Officer
Vineyard Wind, LLC

[2] Because no such concept is expressly described in the legislation, developers such as Vineyard Wind have already made significant investments since June 2016 in planning for the permitting, construction and interconnection of their projects to the electric grid. To upend these investments, which were based on reasonable expectations about the process, would risk driving up project development costs for the projects, and for the ratepayers who are their customers.

Issues for Stakeholder Comment

Please provide concise answers to the following Stakeholder Questions

1. Please provide the following information with your comments:

    a. Name of Organization

    Vineyard Wind, LLC

    b. Type of Organization (Public/Industry/Advocacy/Other)

Offshore wind project developer and Massachusetts offshore wind lease holder. Vineyard Wind is a portfolio company of a Copenhagen Infrastructure Partners ("CIP") administrated fund. Currently CIP is involved in two offshore wind projects under construction, the 402 MW Veja Mate project in Germany and the 588MW Beatrice Project in the UK. The team members from CIP have extensive experience in the development of commercial-scale offshore wind in global markets. Collectively the team includes experience from more than twenty offshore projects totaling several thousand megawatts of offshore wind that is in operation, under construction or under development today.

2. Section 83C of Chapter 169 of the Acts of 2008 ("Section 83C"), as amended by Chapter 188 of the Acts of 2016, An Act to Promote Energy Diversity, requires a solicitation to be issued by June 30, 2017, including a timetable for the solicitation. Please respond to the following questions regarding the timetable:

    a. How much time do bidders need to develop proposals?

In order to prepare competitive and robust bids, developers need good site characterization data. It takes approximately one year to conduct site characterization, in particular a summer season for geological surveys. Governor Baker's signature on the Act in August, 2016 signaled to lease holders that they should begin collecting this data in anticipation of bidding in June 2017. Allowing for a couple months for preparation and deployment, this means that by September-October 2017, developers would have had a full year to collect site data. Allowing for another couple of months to analyze the data and incorporate the findings into bids, this means that developers should have had sufficient time to prepare and submit robust bids by November-December of 2017, and therefore Vineyard Wind recommends bidders have 90-120 days from the date of the RFP to submit their bids. Assuming that the full solicitation schedule for the entire 1600MW procurement is set out at the time of the first RFP, bidders will need less time, perhaps just 2-3 months, to develop proposals in response to future solicitations.

        i. What market conditions (technology, vessels, local supply chain, etc.) or ongoing data collection might necessitate a shorter or longer time period for proposal development?

Supply chain factors, such as technology changes, vessels, etc., is not a limiting factor in developing proposals. A developer might have to make certain supply chain commitments prior to Financial Close, but this should not limit the ability to provide proposals during Q4 2017.

b. Section 83C allows the use of a staggered procurement schedule and, if applicable, specifies that a subsequent solicitation "shall occur within 24 months of a previous solicitation."

   i. How should the timing of future solicitations be staggered in time?

Vineyard Wind strongly recommends four solicitations, of 400MW each, over four years ("4 X 400") for the following reasons:

Lowest cost

- 83C requires that each long-term contract executed under the Act (a power purchase agreement or "PPA") be at a lower price than the previous PPA awarded—the price ratchet. Thus, having four solicitations makes it much more likely that the average price of the full 1600MW will be lower than if there were only two or three solicitations.

- Multiple and frequent solicitations will give project developers an incentive to refine their designs and plans in the following competitive solicitations. Future solicitations will benefit from a competitive supply chain landscape as well as technology innovation. In contrast, fewer bids of larger amounts would risk a "winner take all" scenario, in which one player could dominate the market and make it difficult for competitors to sustain competitive pressure on the incumbent.

- A 400MW project size is large enough to capture economies of scale, yet still has the advantages of multiple, smaller solicitations as described above. Furthermore, project sizes approaching 700-800MW would start to see potential supply chain constraints. An example of this would be potential challenges in deployment of very large projects out of the New Bedford Marine Commerce Terminal, as noted in the section below.

- Quickly awarding a 400MW procurement now would give developers the opportunity to make use of the federal Investment Tax Credit (ITC), which would benefit ratepayers, while at the same time allowing the Commonwealth to capture future price reductions due to improved technology and infrastructure and supply chain development throughout the offshore wind industry.

Maximize economic development

In order to maximize economic development over the long-term, it is essential that the state quickly establish a growing offshore wind industry, as opposed to being focused on completing any one project. Vineyard Wind sees no benefit to risking the start of an industry by being overly ambitious in the first procurement and aim for projects that are significantly larger than those currently under construction in the significantly more mature markets in Europe.

- A 400MW project is an optimal size to start an offshore wind industry in Massachusetts. It is large enough to attract the interest of experienced supply chain companies, but not so large that those companies would be forced to utilize their existing facilities in Europe in order to reliably meet the schedule. Also, 400MW is a sufficient size to incentivize investments by Massachusetts companies that may allow them to participate, but not so large as to prevent their entry due to lack of experience or facilities. We are confident that the fact that the first project would be one of four projects will attract considerable investment based on supply chain conversations Vineyard Wind has already had.

- Just as the multiple project opportunities would benefit ratepayers, so too would it benefit local companies and new entrants into offshore wind. Supply chain companies that lost an opportunity to supply one project would have a year to improve their offerings and try again, without having to sustain their initiatives for more than a year waiting for the next opportunity. Larger solicitations would have to be spaced over a longer period, resulting in a "boom and bust" scenarios that would reduce competition in the supply chain.

- Based on our analysis to date, 400MW could be built in one year using the New Bedford Marine Commerce Terminal. Larger projects would likely drive developers to look at additional facilities outside of the state in order to ensure they can meet a cost-effective construction schedule. Furthermore, projects going to construction approximately every year would allow for a significant amount of local equipment and infrastructure to be quickly re-used, and for a local workforce to remain intact.

- More solicitations would provide more opportunities to develop solutions to issues unique to Massachusetts and the U.S. (for example the Jones Act and limited purpose-built infrastructure).

<u>Experience in Europe</u>

As depicted in Appendix A, average project sizes in Europe over the last five years make a convincing case that 400 MW is approximately the right size for Massachusetts as well. Please refer to the figures in Appendix A regarding an analysis of European offshore wind farm sizes.

- Average wind farm size in the European markets over the last five years (sites with commissioning dates of 2012 or later) in the United Kingdom, German, Denmark and the Netherlands is approximately 370 MW.
- An 800 MW project would be greater than any project currently operational (the largest is the 630 MW London Array 1 in the UK), and only one project globally has ever reached financial close above 714 MW in size.

<u>Better environmental outcomes</u>

- The rapid deployment of large amounts of offshore wind is critical to Massachusetts meeting its GHG reduction requirements. Therefore, having four projects underway over the course of four years would diversify the risks of project completion, and of putting those needed reductions at jeopardy. Should one project stall or fail, the others could proceed on schedule, and additional solicitations could be conducted. In contrast, a significant delay in a larger project could be a larger portion of the entire 1600 MW allotment at risk.

- The more frequently competitions occur, the more readily new technologies and techniques can be utilized in Massachusetts. This can have environmental benefits to the extent these newer technologies and techniques reduce environmental impacts; for example, foundation installation or marine mammal detection.

ii. What market conditions (technology vessels, local supply chain, etc.) or ongoing data collection should be considered when determining the timeframe of future solicitations?

Vineyard Wind recommends that the schedule for the full 1600MW procurement be set prior to, or simultaneously with, issuance of the first RFP. This would allow bidders to plan additional data collection, conduct design work, and make supply chain investments to drive down project costs. This long-term schedule would also allow for planning the most efficient build out of each lease area, reduce permitting costs, and facilitate planning supply chain investment.

We firmly believe that setting a long-range schedule for the full 1600MW would have a bigger, positive impact on the supply chain competition and economic development in Massachusetts offshore wind than any other factor in terms of data gathering or market conditions.

3. Section 83C requires that the initial procurement be issued by June 30, 2017, and any individual solicitation "shall seek proposals for no less than 400MW of aggregate nameplate capacity of offshore wind energy generation resources." In each of your responses, please include an explanation of how your suggested approach would lead to a more cost-effective result for ratepayers.

   a. What is the maximum megawatts of aggregate nameplate capacity that should be sought in the initial solicitation under Section 83C? Should the initial solicitation request minimum megawatts of aggregate nameplate capacity greater than the statutory requirement of 400MW? If so, why?
   b. What considerations should be taken into account in deciding the size of this initial solicitations and, if applicable, the size of future solicitations?

   c. Based on your response to the previous question (3b), what minimum and/or ma ximum megawatts of aggregate nameplate capacity of offshore wind energy generation ("OSW") resources should be sought in future solicitations?

For all of the reasons above, a 4 X 400 MW approach should be used.

In addition, Vineyard Wind strongly urges that each solicitation specify a specific project size within a very narrow range of sizes- for example, plus or minus 10MW to account for incremental size of turbines or to maximize utilization of the transmission capacity. Allowing developers to propose various project sizes of their own choosing would complicate bid evaluation, which in turn could delay the deployment of offshore wind and potentially undermine confidence in the process. Vineyard Wind believes that allowing developers to propose various sized projects will inevitably lead to a strategy of proposing very large projects in order to win the most capacity, defeating the benefits of multiple solicitations outlined above. In contrast, more frequent competitions for a fixed 400 MW (the greatest number of competitions allowed under the statute, assuming the projects are successful) would result in a lower average price.

d. Recognizing that Section 83C calls for proposals no less than 400MW of aggregate nameplate capacity of OSW resources, what are the pros and cons including impacts to the market and to the cost to ratepayers of selecting multiple bids with individual project sizes less than 400 MW.

Section 83C requires each individual project to be at least 400MW

Vineyard Wind disagrees that Section 83C permits an interpretation whereby proposals for less than 400MW are allowed. Our reasons are as follows:

- First, a plain reading of the language included in Section 83C(b) makes clear that proposals must be for 400 MW: "individual solicitations shall seek **proposals for no less than 400 megawatts** of aggregate nameplate capacity of offshore wind energy generation resources." (See 83C(c), emphasis supplied). The reference to 400 MW modifies the word "proposals" not the word "solicitations".

- To suggest that individual proposals may be for less than 400 MW would require parties to essentially read-in words that are absent from the text. If the Legislature had intended to allow for individual proposals for amounts lower than 400 MW it could have, and would have, specified that by stating that "individual solicitations shall be for no less than 400 MW" or by using terms "provided that individual proposals may propose any amount." **Instead, the Legislature made clear that the proposals, not the solicitation, shall be for no less than 400 MW**.

- The fact that this amount applies directly to a single project, with a single price for the entire 400 MW, is clearly reinforced by the very next sentence in the Act which states that "the [DPU] shall not approve a long-term contract that results from a subsequent solicitation and procurement period if the levelized price per megawatt hour plus associated transmission costs, is greater than or equal to the levelized price per megawatt hour plus transmission costs that resulted from the previous procurement." Id. There is no reasonable way to understand what "the" single levelized price per MWh would be for a prior procurement that awarded multiple contracts for an aggregate of 400 MW. [3]

[3] Likewise, reading the entire Act in context makes clear that this is the intended result. The Act gives a range of discretion to the DOER, EDCs and DPU to propose and approve solicitations that would range from 400 MW to 1600MW in a staggered procurement schedule over ten years (provided that each solicitation shall occur within 24 months of a previous solicitation)—but it clearly calls out "proposals for no less than 400 MW". Allowing an interpretation that suggests the Legislature really intended any number of smaller project proposals effectively reads out the floor for minimum proposal sizes that appears to have deliberately included.

Allowing projects less than 400MW would undermine the objectives of offshore wind policy

Even if Section 83C allowed for awards to be made to projects less than 400MW, doing so would result in higher costs to ratepayers, less economic development opportunity, and less environmental benefit. Specifically:

- Awarding of contracts for less than 400 MW will result in selection of the lowest price bid, and also the second lowest price bid to reach the 400 MW aggregate. This is clearly not in the best interests of ratepayersand the difference between the lowest and next lowest bid could be significant. Ratepayers would be better served by selection of the single lowest bid that meets the 400 MW threshold.
- Multiple projects commencing in the same year will leave New Bedford Marine Commerce Terminal with competing uses, rather than a coordinated and well-paced build out over years.
- A minimum scale is necessary to actually jump start this industry and to lead to replicable utility-scale contracts that will support the further build out of offshore wind in the Commonwealth.
- Smaller projects are also likely to lack economies of scale and require higher prices, and will be less likely to attract supply chain investment to Massachusetts.
- By allowing the projects of less than 400MW be proposed, it is possible if not likely that less than 400MW would be awarded as a result of any one solicitation. This would delay the implementation of the full 1600MW, diminishing the GHG reduction potential of the offshore wind policy.

Allowing projects of less than 400MW increases complexity and reduces transparency in the solicitation process.

It is difficult to envision a proposal selection process that allows for projects of less than 400 MW to be bid, from only three or four bidders, that was sure to achieve 400 MW total, and that was sure to achieve the lowest cost for ratepayers. Any means to sort out these factors would take longer to implement, and would be confusing to bidders and the public alike. Furthermore, this evaluation would somehow have to take place from one solicitation to the next, in order to ensure that subsequent projects are less expensive than previous, as required under Section 83C. All of the above would result in an overly complicated, difficult to follow and understand, possibly less than fully transparent bid process, which would risk the first solicitation failing or subject to delay.

e. What potential future changes in the market should be considered in determining the size of aggregate nameplate capacity of OSW resources sought in future solicitations?

As described in detail above, our recommendation is not to change future solicitation sizes, but to instead establish a schedule now for all the solicitations, and that this schedule should be four solicitations, for 400MW projects, over four years. Even if it becomes necessary to adjust this schedule at a later date, the experience in Europe has shown that having clear visibility of the solicitation schedule will be the single most important factor in driving down the cost of offshore wind in Massachusetts and ensuring the establishment of an on-going industry.

Expected changes in market are mostly technological improvements, such as larger rotor size. These would all result in lower prices without need to change the solicitation size, indeed, especially if the solicitation schedule is fixed from the start it would be easier and provide more time for developers to plan how and when to incorporate new technologies when mature and available in the market.

4. Section 83C requires the evaluation team to carefully review of any transmission costs associated with a bid. Please respond to the following questions regarding the evaluation of related transmission costs:

We understand that DOER, the EDCs, and the Independent Evaluator should and will be carefully evaluating all aspects of the proposals. However, as outlined in the introduction, the best way to drive bid prices lower is to place the burden on developers to deliver an “all-in” cost that incentivizes avoidance and mitigation of development risks as much as possible, including any transmission cost overruns. This provides the developer, who controls the fabrication and installation of the offshore connection, with a strong incentive to make sure the project comes in at the agreed upon price— a much stronger incentive than an ability to pass through cost over-runs to ratepayers. Developers are in turn of course able to manage the risks of the transmission costs however they see fit, whether by developing the transmission entirely on their own, teaming with another entity, or purchasing transmission capacity from a provider. This “end to end” project delivery model puts the risks on the developer, not the ratepayer

a. What documentation and information should bidders provide in order to demonstrate the reasonableness of their transmission costs estimates included in their bid?

Bidders should provide a design, timeline and estimated costs for the transmission portion of their proposed projects. The requirements to provide information regarding the transmission costs should not be significantly different from the information requirements for any other aspects of the project.

b. Please describe, in detail, how transmission cost risks should be analyzed in the quantitative portion of the bid evaluation.

The way to avoid transmission costs risks altogether is to require “all-in”, $/MWh bids that include transmissions costs at the developer’s risk. This is what Section 83C calls for, and therefore there no particular analysis of transmission costs risks, aside from establishing that a bid is credible in all aspects, is required or needed.

c. What type of cost containment features might a bidder use to ensure that transmission cost overruns, if any, are not borne by ratepayers as required by the statute?

Bids should be for a fixed price, and should include all project related costs including transmission costs. If a developer then fails to contain their transmission costs, they will either have to complete the project (albeit at lower returns on their investment), or abandon the project and forfeit their PPA security. In no case would ratepayers be responsible for any cost overruns, including transmission cost overruns.

5. Please respond to the following interconnection-related questions:

   a. How should the procurement be structured to allow reasonable evaluation of bids that have not completed the ISO-NE I.3.9 process?

We assume that by "ISO-NE I.3.9 process", the question refers to the grid connection application process generally[4]. Given this, it would be appropriate for the bidder to reference previous studies or analysis in the area and the developer's own studies and analysis, if needed, to demonstrate the practicality and expected costs (if any) of proposed interconnect plans.

   b. For bids that have not completed the ISO-NE I.3.9 process, what information, such as technical reports or system impact studies that closely approximate the ISO-NE interconnection process, should the procurement require from bidders to allow a complete evaluation of bids and associated risks, costs, and benefits?

Provision of such information is not necessary in order to protect ratepayers from incomplete cost estimates. Rather, the RFP should simply require all-in, $/MWh bids, including all transmission costs, as called for in 83C.

   c. What documentation should the procurement require bidders to provide that demonstrates the reasonableness of their estimates for interconnection costs and deliverability costs (costs of network upgrades including reactive compensation, and voltage control to compensate for cable charging)?

An evaluation of transmission costs to ascertain overall proposal credibility is needed, as with any other costs. For this purpose, bidders could provide preliminary design and cost estimate based on market experience and indicative pricing or bidding from suppliers.

   d. What other cost containment information should the solicitation require bidders to provide to allow for a complete evaluation of bids and associated risks, costs, and benefits?

No cost containment information is needed, given that bids should be, as called for in Section 83C all-in, $/MWh bids, with any cost overruns fully at the risk of the developer.

   e. What potential impact, if any, does the cluster interconnection analysis being developed by ISO-NE have on developing transmission costs and/or transmission planning for OSW?

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[4] ISO-NE I.3.9 could be understood to reference a particular, last step in the ISO's grid connection process, as opposed to the connection application process generally. If the question intended to reference this last step only, then our response would be to say that we understand from consulting with a number of experts that rarely does this last step identify costs or reliability issues that weren't identified in the SIS and other, earlier steps of the application process. Furthermore, even if additional costs were identified, no cost overruns protections are needed, assuming the RFP simply requires all-in, $/MWh bids.

For the purpose of the bid evaluation, it is not necessary for the bid evaluation team to take a view on the impacts, if any, on the cluster interconnection analysis. Rather, bids should be all-in, $/MWh bids, with any cost overruns fully at the risk of the developer, as called for in Section 83C.

6. Section 83C requires that projects must be "cost effective to electric ratepayers in the Commonwealth over the term of the contract." What could bidders include in their proposals to ensure that the long-term contracts for OSW will be the most cost effective to ratepayers?

Ratepayers can be best assured of a cost-effective project if 1) the project is built at the bid price, and 2) the bid price provides price stability or at least is not inflationary.

<u>All-in, $/MWh bids</u>

The best way to ensure cost-effective bids, which are readily and correctly evaluated, is to require all-in, $/MWh bids only. Post-award price adjustments (aside from those due to indexing to a publicly available inflation index), cost-pass throughs, or other such mechanisms that would allow cost overruns to creep onto the ratepayer should not be allowed.

Similarly, to the extent a bidder seeks to qualify for the ITC in a bid, the risk of not receiving the ITC as expected should be fully with the bidder. Allowing bids both with and without ITC assumptions could lead to a "gaming behavior", in which a bidder is overly optimistic about the ITC, knowing that if they are unable to get the ITC they will then receive a higher price anyway. Reverting to a next lowest bid in the event the winning bidder does not get the ITC would not be feasible, given that some years would likely have passed, and previous bids would have gone stale.

<u>Price stability</u>

An important consideration in evaluating bids is the balance between lowest initial price, and price stability. A fully fixed price is likely to come at a higher initial price because a fully fixed price creates risks for bidder, who need to take into account future inflationary costs.

Given this, we recommend that bidders should be able to bid a price that is indexed to a publicly available inflation index, such as CPI. This would provide ratepayers a balance of lower initial cost, but also provide a price stability benefit for ratepayers, as the offshore wind would only adjust to economy-wide variation, and thus still provide protection against energy commodity prices, which are increasingly volatile. We would recommend against allowing adjustments based on a fixed percentage, as this would negate both price stabilization and, over time, any lower initial cost benefit as the prices grows on a compounding basis regardless of current inflation rates. Bidders should also be able to offer two bids, with variations on the indexing utilized, so that evaluators have more opportunity to find a right balance between price stability and fixed price.

Lower ratepayer costs by efficient risk allocation

As stated above, Vineyard wind fully supports that all reasonable risks are carried and priced by the developer. However, we would also expect a final PPA to have provisions protecting a developer from risks that it has no means to mitigate, including, but not limited to: (i) any change-in-law which significantly changes the key assumptions on which the bid was based, (ii) significant changes to the ITC or PTC components of the tax code[5] , (iii) new regulation or new regulatory standards being introduced that would significantly delay the project obtaining permits to construct the project in a reasonably anticipated timeframe, (iv) Force Majeure-type events or similar.

Protection should only be given for rare and unusual events and could include the ability to recover the bid bond or have an appropriate adjustment to the PPA if approved by the DPU.

7. Section 83C requires one or more procurements of OSW and requires that long-term contracts be "cost effective to Massachusetts electric ratepayers" and "avoid line losses and mitigate transmission costs to the extent possible" and ensure that transmission cost overruns, if any, are not borne by ratepayers." The transmission needed to deliver OSW generation resources to shore could have a significant impact on customer costs, benefits, and risks. Please address the following questions:

    a. What potential approaches related to the transmission portion of the RFP(s) should be considered when designing the RFP to achieve the total OSW procurement goals of Section 83C? For example, potential approaches might include requiring each generation bidder to fulfill its own transmission needs (either with other bidders, with partners, or by themselves) or might include delivery to a common off shore delivery point. Full descriptions of each potential approach would be helpful.

The best way, perhaps the only way, to ensure that transmission costs overruns are not borne by ratepayers is to require each project to provide its own transmission solution, and the costs of such transmission solution should be included in its all-in, $/MWh bid price. This approach will also ensure that the transmission solution will be cost-effective, avoid line losses and mitigate transmission costs to the extent possible, because the project developer will have strong incentive (wanting to get to lowest price to win a bid) to ensure the transmission is cost-effective, avoids line losses, and mitigates transmission costs.

Approaches using a "shared" grid connection or common offshore delivery point have inherent risks to the generation developer (described in detail below), and this risk will of necessity result in higher costs. We note that because of these complexities, the most common instances where shared or common transmission solutions has been utilized previously are in those cases where projects are located far out in the North Sea (50+ miles) where there was no choice but to utilize

[5] To be clear, as indicated in Vineyard Wind's response to Question 6, the risk of not being able to utilize the ITC/PTC due to the bidder's failure to qualify for the credit should absolutely remain with the bidder. The distinction is a scenario where Congress remove's the bidder's ability to access the credit, which is a significant and fundamental changed circumstance outside the bidder's control.

such a shared grid connection despite the many problems and challenges. The distances offshore of all lease areas here in Massachusetts are far shorter.

Therefore, we highly recommend not utilizing a shared grid connection approach until later solicitations, and only after these risks have been effectively addressed and efficiently allocated.

b. Identify the pros and cons of each with particular focus on consumer costs, benefits, and risks.

Cons of attempting a shared grid connection

A shared offshore grid connection is an extremely complicated undertaking, and untried in the U.S. It is complicated technically, commercially, legally, and in terms of environmental impacts. Such an approach comes with many questions and issues, all of which would need to be addressed in order to develop a realistic plan, but none of which have quick or easy answers. Some of those questions and issues are listed below.

Because of this complexity, any attempt to implement a shared grid connection as part of the first solicitation will inevitably result in delaying Massachusetts's first offshore wind project, with no assurance that such delay would provide any additional benefits to ratepayers or achieving Section 83C's purposes.

Questions and issues with a shared grid approach include:

- Do state laws that apply to regulated utilities also apply in federal waters? Does FERC have jurisdiction over offshore wind grid connection, given the responsibilities given to BOEM by statute and subsequent agreements between the agencies?
- What entity would build out such shared transmission, and how would that entity be selected (and if it is selected on a competitive basis, there would of necessity be further delay and complication to the first offshore wind project, given the necessity to conduct such a competition).
- How would the shared transmission be funded? The answer is not found in 83C in our view, and therefore would have to be sought through other federally regulated processes.
- Who pays for idle generation if the offshore wind project is ready but the transmission project is delayed? European experience, in particular from early shared transmission projects in the German North Sea, caused significant delays in connecting projects to the overall grid resulting in lengthy litigation and losses exceeding hundreds of millions of Dollars, all of which were born by the rate-payers. e
- Who pays for unused transmission capacity if the generation is down?
- Who pays for the unused transmission capacity during the period when there would be excess transmission capacity, perhaps for years, in anticipation of future generation? What happens if there is substantial delay until the next OSW projects are ready to make use of the shared transmission?
- Who pays for transmission outages or curtailment? How is the generator compensated in the event of transmission outage or curtailment (not having a compensation mechanism will add risk and therefore add cost to the project and to ratepayers)?

- Where would the shared interconnection points be located, and how are assurances made that this location doesn't disfavor an otherwise favorable project?
- What are the interfaces in terms of permitting? That is, at what point between our offshore platform and the point of connection to a shared transmission system are we responsible for permitting, and the shared transmission company responsible for permitting?

Inherent to most of these questions are risks. At the end of a lengthy regulatory process, these risks could be allocated to different parties. But this is not the same as fully mitigating these risks. In the end, the ratepayer will have to pay for the additional risks a shared grid connection approach brings.

Requiring a shared grid connection bid will also introduce additional complexity in the Section 83C bidding process, increasing the risk that the first solicitation will not go smoothly, and thus delaying or undermining launch of the Commonwealth's offshore wind policy. Examples of such complication include how to handle scenarios where the lowest generation bid has the highest transmission cost? In contrast, requiring the developer to provide the lowest bid inclusive of transmission, without opportunity to pass cost over-runs on, is simple and transparent, and therefore more likely to result in a solicitation without difficulties or delays. Even if the bid process went smoothly a shared grid connection will of necessity (given the many issues above to be resolved) take longer to implement than requiring the developers to provide their own transmission solutions.

The only benefits we can see of a shared transmission solution are speculative or hypothetical, and could only be tested through considerable analysis of specific, real world situations. For example, a shared grid connection could require less cable to be buried under the seafloor, thus reducing environmental impacts…or, a shared connection solution could also require more cable than several, short connection cables to separate projects. It's not possible to say without considering the full range of possibilities.

<u>Benefits of the wind project providing its own transmission</u>

The benefits of each wind project developer providing their own transmission solutions include:

- Ratepayers have full protection from cost overruns.
- The "generator builds its own connection" approach has been the industry norm for many years, ever since much of New England deregulated. The process is well known and understood, thus better ensuring timely, efficient and transparent bid evaluation and implementation.
- Instead of having two parties responsible for two different aspects of the project, the generator build approach puts the entire project development in the hands of the one entity which is both highly motivated, and has the means, to ensure an on schedule and on budget project.

c. What elements of each option might increase or reduce customer benefits to the greatest extent? What elements might increase or reduce customer risks? Please explain your answers.

Requiring the wind project developers to provide for all transmission costs in their $/MWh bid would eliminate all risks to ratepayers of cost overruns.

d. How might these approaches be affected by the size and timing of Section 83C solicitations?

Attempting to implement a shared grid solution for the first or second solicitation risks implementing a process that is not fully vetted, and which could lead to unintended consequences such as delays and legal challenges. The larger the solicitation that is required to use a shared grid connection, the larger the negative impacts if the shared grid connection fails for any of the reasons discussed above.

e. The RFP could require an additional bid that assumes the bidder's OSW facilities interconnect at a pre-defined transmission point constructed at an off-shore location by a Transmission Developer. If included in the RFP, the bid would be in addition to the requirement for each bidder to provide a proposal in which its OSW facilities would interconnect to the existing on-shore transmission network. On the assumption that the RFP includes such an off-shore proposal, please address the following questions:

   i. What elements of this approach might increase ratepayer benefits to the greatest extent? What elements might reduce ratepayer benefits? Please explain your answers.

The only means of effectively addressing the inherent challenges and risks of this approach (or maximizing the potential benefits, if any) is to undertake careful planning, and to advance the concept in a deliberate and well considered manner. There should be ample opportunity for stakeholder input, review of legal questions and analysis of technical issues.

   ii. What minimum level of technical information regarding such a pre-defined off shore location will bidders need in order to allow them to provide accurate and complete bids based on this scenario? Please explain.

We would need extensive technical specifications of the offshore connection point, and the cable connecting it to the shore. Further details can be provided upon request, but to summarize, we would need the same information that we can now obtain about the existing on-shore substations and the cables leading to them. This is because our cable connecting to the shared connection point will interact with the equipment and cable that makes up the shared grid connection point, for example with regard to charges currents. We will also need this information in order to design our transformer system, and to analyze risks of outages and curtailment, which in turn is needed in order to secure financing. Furthermore, we would need to immediately submit an interconnection agreement request to the ISO-NE, and so we would need all the same information required by ISO-NE in order to submit that request.

In addition to electrical information, we will need other engineering details such as where the connection point is located, where and how our cable would be connected to the common connection point, installation procedures, and interface protocols. This information is needed in order to design, permit, and cost estimate our cable and connection system.

A joint O&M plan would also be needed, in order to incorporate into our own O&M plan, account for necessary costs, and analyze the risks of the plan.

iii. What additional (i.e., non-technical) information will bidders need in order to allow them to provide accurate and complete bids based on this scenario? Please explain.

We would need forms of all agreements between ourselves and the owner and operator of the shared grid connection system, and these forms would have to be tested in the finance market to determine if they would support project financing. We would also need to fully understand the balance sheet and financial profile of the entity owning and operating the shared transmission system, as the agreements are only as good as the ability of the counterparty to execute on the agreement. We also need to fully understand the consequences if the shared connection point is not ready on schedule, or if we are not ready with our generation on schedule. These risks and the costs of these risks will be needed in order to determine the costs of our obtaining financing for the project. Furthermore, there may be additional or unanticipated costs or risks put on us as the wind project developer, even if we don't actually own or operate the shared transmission system. All of this would have significant impacts as we go to calculate our costs, and therefore our bid price.

We will also need a detailed (to the month) schedule of when the shared offshore connection point would be constructed and ready to operate. This information is needed as we will need to integrate our construction schedule with that of the shared grid connection point. The construction schedule is a major determinate of projects costs and risks.

iv. What such approach will allow the most efficient and cost-effective result? What circumstances or approaches could potentially diminish the efficiency or cost-effectiveness of such a network expansion? Please explain your answers.

As described in further detail above, the most efficient and cost-effective approach is to require the wind project developer to develop, finance, own, and operate its own grid connection system, and to include these costs in its $/MWh bid price. With a generator build approach:

- Ratepayers are fully protected from transmission cost overruns;
- Wind project developers can provide the lowest possible bid because they will have access to all information necessary to develop their bid, and have full control over the entire project design and execution;
- The Commonwealth's offshore wind policy can be launched quickly and efficiently, and projects built quickly, without the delays that will inevitably result from designing and implementing a shared grid connection policy, getting it through the regulatory and permitting process, and then actually constructing the project.

f. Describe what other mechanisms or requirements should be considered for reducing the short-term and long-term costs of transmission interconnecting OSW facilities. For example, are there steps that could be required for transmission associated with the first OSW project that could reduce overall costs to ratepayers when subsequent OSW project(s) and their associated transmission are built?

Aside from those requirements discussed above – in particular requiring transmission costs to be included in the $/MWh bid price-- we do not see any mechanisms, steps or requirements of a first project that could reduce overall costs to ratepayers. For example, a requirement or incentive for first projects to “over-build” their transmission so that the excessive capacity would be available to later projects would have many the same problems as a “shared transmission” approach (see above for details). Nor do we see that such an approach would necessarily bring any benefits; for example, requiring or incentivizing additional cable capacity during a first project could just result in more cables being installed, with their associated environmental impacts, that later are found not to be needed. We also note that a transmission capacity overbuild approach would have to be examined with regards to FERC regulations and precedents, and that this would result in delay and complexity that should be avoided when possible.

8. Section 83C requires that projects “adequately demonstrate project viability in a commercially reasonable timeframe.” How should the solicitation address this requirement? Please address the following questions:

    a. The RFP may require all proposals to meet an in-service date for generation, what is the earliest that date should be??

We fully support that projects need to be built in a reasonable timeframe, and as discussed below there are ratepayer and other benefits to projects coming on-line earlier than later. However, we highly recommend that “cliff edge” sort of PPA schedules, i.e. fixed date milestones with punitive penalties or termination provisions, should be avoided. Such cliff-edge schedules raise developers’ risks, and therefore costs to ratepayers, without providing means or incentive to avoid delay.

Instead, we would recommend building incentives into the bidding requirements, and the PPA itself, for developers to come on-line at the earliest date possible. One recommendation for a simple and transparent incentive, which would also provide a savings to rate-payers, would be to have any price indexation start at the Commercial Operations Date (“COD”), and not at the date of awarding the PPA. By starting the indexation of the bid price at COD, developers would be incentivized to advance the in-service date as early as possible. At the same time, bidders would not face any cliff-edges if their plans are delayed, and so no risk premium for such cliff-edge would have to be included in the bid price. Ratepayers would also realize additional benefit in that the bid price would be fixed for the period between PPA award and COD, however long or short a period that might end up being.

We appreciate that even with such an incentive approach a long-stop date requirement may be desired as well, for example to facilitate bid evaluation, or for the sake of good legal structure to the PPA. We suggest a long-stop date between the date on which both permit and grid connection rights are in hand and initiation of project execution (e.g. financial close and entering supply and installation contracts) of two years. In addition, a long-stop date of four years between PPA award and initiation of project execution would be a reasonable long stop date. Once the project has entered project execution, the developer is incentivized to have it constructed on time to avoid costly cost overruns why a long-stop date for this phase is not required.

We would also recommend that developers be able to cure missed deadlines (and other milestones) through additional security payments. This would prevent cliff-edge losses of significant investment due to missing deadlines by small amounts, or missing an opportunity to correct a schedule setback after the deadline has passed.

b. Should proposals that commit to an earlier commercial operation date be favored over projects with later commercial operation dates? Please provide reasoning to support your response.

There are benefits, including benefits related to the non-price evaluation criteria of 83C, of earlier in-service dates. For example, an earlier in-service date would result in earlier GHG emissions reductions, and possibly larger amounts of GHG total, and GHG reductions is a key purpose of the statute. An earlier in-service date would also likely necessitate earlier construction activity, so that economic benefits would be realized sooner.

In evaluating the various non-price selection criteria, the impacts of an earlier in-service date in the proposed project schedule should be taken into consideration. For example, if two projects provide the same reliability benefits, but one project would come in-service earlier, the earlier project should be given the more favorable evaluation regarding reliability, because the benefit of the reliability would be provided sooner and therefore be more advantageous to ratepayers.

Evaluators should also consider that projects proposing sooner operation dates may be stronger, in that they would of necessity be utilizing existing technologies. Proposals with later operation dates would likely plan to be using technologies not yet commercially available, and thus the proposal would be not as strong in terms of certainty of delivery.

c. In a construction plan what documentation should bidders be required to provide to reasonably inform the evaluation team about the project's viability?

Such documentation should include a development and construction plan setting out the main milestones of the project However, we would not recommend requiring signed agreements of any type with suppliers, or specific pricing from prospective suppliers, as this puts constraints on the commercial discussions between developer and supplier which could easily result in higher project costs.

d. How should logistical constraints be addressed in the solicitations relative to such things as port constraints, availability of vessels, etc.?

The developer should describe how these issues will be addressed in the proposed development and project plan. The RFP should specify any particular issues that the evaluation team finds requires particular scrutiny, so that the proposal can directly address the issue.

e. What information should the solicitation require regarding site control for proposed transmission routes, points of interconnection to the grid, and port locations for staging?

Only proposals from projects which hold an BOEM OCS lease, which carries with it rights to offshore cable route, should be eligible to bid. Accepting bids on speculation of obtaining an

OCS lease in the future would risk selecting a bid that later proves unviable if the lease is not later obtained, and possibly encourage attempts to acquire lease areas outside of the areas that have been determined appropriate by the BOEM/Massachusetts Stakeholder Task; this in turn could lead to greater environmental impacts from offshore wind projects.

Because there are many more options for on-shore cable routes and locating on-shore equipment, bidders should not be required to demonstrate any on-shore site control or ROWs. In fact, doing so could result in higher costs, as developers would be constrained in their commercial negotiations to obtain such control and access. Information regarding port locations should be contained in the project plan, but as with other on-shore locations demonstrating contracted access should not be required.

9. Section 83C stipulates that DPU shall not approve a contract from a subsequent solicitation "if the levelized price per MWh, plus associated transmission costs, is greater than the levelized price per MWh plus transmission costs that resulted from the previous procurement." Please address the following question:

    a. What information should the solicitation require, that is different from information that would already be provided on bid parameters and pricing for a specific bid category, to enable an accurate and transparent estimate of the levelized price of energy?

In order to have a fair and accurate test of this price reduction requirement, we suggest the following:

- Bids should be for all-in, $/MWh, with no price-openers or pass throughs;
- Any indexation should be based on an actual inflation index that is publicly available (as opposed to an arbitrary percentage of adjustment or undisclosed index);
- In evaluating a subsequent bid, any indexation that is to be applied per the PPA should also be applied in determining the price that must be beat in order to make a contract award;
- This price adjustment should be established as of the date of the RFP issuance, so as to allow full transparency in the evaluation process, and so that bidders know the number they need to come in under as they prepare their bids.

10. Section 83C requires that the clean energy resources to be used by a developer under the proposal to contribute to reducing winter electricity price spikes. How would bidders demonstrate that proposed long-term OSW contracts can meet this requirement? How should the evaluation process consider bids that cannot demonstrate an ability to meet this requirement?

    Publicly available information about the wind resource offshore of Massachusetts indicates that much of offshore wind's generation will in fact occur during the winter months because that is when the wind is blowing most frequently. (See Appendix B: "Seasonal Wind Distribution"). Therefore, offshore wind is a resource that is extremely well suited to helping the Commonwealth's address its reliability needs during the winter months. At the same time, the reliability issues, and economics around ensuring reliable delivery during the winter months, are very different between offshore wind and other forms of clean energy generation. Specifically, because so much of an offshore wind farm's revenue is earned during the winter months, project operators already have enormous incentive to ensure delivery of energy during the winter season. We note that these differences between land-based clean energy sources and offshore wind are reflected in the statute as well. It is noteworthy that Section 83C only has a requirement to reduce winter price spikes, and does not contain the broader winter delivery requirement found in Section 83D.

Given the above, we would urge that the need to contribute to reducing winter price spikes be approached differently from that adopted in the proposed Section 83D RFP. Instead, we recommend an approach as follows:

- First, instead of a winter months' production requirement as in 83D, bidders should be required, after the first full year of operation, to meet a minimal availability requirement of 70% during the winter peak months. The availability requirement should also be based on an average for the winter peak months for a minimum of three years. Projects would be required to document compliance with this requirement by annually submitting supporting information. The use of an availability measurement (instead of a productivity measurement) is justified because it is much more difficult to measure the offshore wind resource, and expensive to do so in early development stages. Furthermore, there is much less historical wind data from offshore, and so it is more difficult to make estimates with a resolution of weeks-to-months. Therefore, it is not practical to expect developers to commit to a production estimate, which would require a better understanding of the wind resource than currently available.

- Second, imposition of any liquidated damages (LD) for missing the minimal availability should have a force majeure provision which waives the LDs when the unavailability is due to an event where the full export capacity is lost and the developer already is occurring a massive financial loss by not being able to sell power. Such provisions are usual in other European offshore markets markets where grid operators either have caps or are able to socialize such costs. While it would be possible to design insurance and emergency repair programs to fully compensate for such rare events, the costs of such programs would, over the life of the long-term contract, far exceed any benefit to ratepayers in the form of avoided winter price spikes.

11. Given that Section 83C allows "offshore wind energy generation resources to be paired with energy storage systems", please respond to the following questions regarding the evaluation of the potential benefits associated with storage being paired with an OSW project:

    a. Should the Section 83C bid evaluation process quantitatively evaluate the potential benefits associated with storage paired with OSW resources potential qualification and participation in other ISO-NE markets, (e.g., ancillary services market)? If so, what methodology should the evaluation team utilize to ensure all the benefits are captured?

    b. Where would energy storage systems potentially be located, and what options should be allowed for ownership and/or operation?

c. Should the operation of storage be completely associated with the OSW project or be allowed to sell services into the ISO-NE markets outside of operation of the OSW project?

Vineyard Wind believes that the requirements for storage envisioned by the Act were appropriately incorporated into the Draft RFP for 83D and would encourage the same approach for 83C.

12. Section 83C states that where possible, proposals should mitigate any environmental impacts. Please address the following regarding this provision:

a. Identify and describe the environmental impacts associated with the installation of underwater transmission cables in state waters. Describe recommended mitigation strategies and explain what commitments and information a bidder should provide to demonstrate that it will mitigate the identified environmental impacts.

Such impacts, and mitigations of those impacts, is dependent on a large number of variables, most of which will vary in different ways among the different project proposals. Given this, we would suggest that each bidder be required to describe the potential impacts, mitigations, and commitments and information to demonstrate mitigation measures, which apply and are relevant to their particular project proposal.

b. Recognizing that the U.S. Bureau of Ocean Energy Management requires developers (as part of their Construction & Operations) to submit a decommissioning plan and post a bond to address decommissioning that is held by BOEM during life of the project, are there additional considerations that a developer should provide in their proposal toward mitigation of decommissioning cost responsibility for ratepayers?

BOEM requires developers to plan for and fund the decommissioning of the project at a very early stage of the project's life cycle. While we appreciate BOEM's rationale for this requirement, we find it overly cautious and adds unnecessarily to the project's costs. In contrast, projects in Europe are not required to start funding decommissioning until much later in the project's life cycle. BOEM's requirements are more than adequate, and any further requirements would only add further costs to the project. Therefore, we would highly recommend against requiring additional measures in this regard.

Regarding funding for decommissioning specifically, this is another instance where an all-in, $/MWh bid is the best protection for ratepayers. Since ratepayers will only be paying for the $/MWh price specified in the PPA, there is not possibility for them to have to take on unexpected decommissioning costs. If a project owner failed in its decommissioning requirements, BOEM would only have recourse to the project company and its financial security, and not ratepayers or counterparties to the PPA.

c. Describe any other environmental impacts that should be considered in evaluating the proposals and the documentation needed to demonstrate mitigation of impacts.

Since environmental impacts and effective mitigation is very dependent on the specific design of each project, we suggest that each bidder's proposal describe any other environmental impacts and mitigation measures. Given the extensive state and federal permitting activities each developer needs to undertake, we believe that requirements to document mitigation commitments should be evaluated for each project on a case-by-case basis through the permitting process and not through the RFP process.

13. Section 83 states that, where feasible, a project should "create and foster employment and economic development in the Commonwealth". Please address the following:

    a. Describe employment and economic development in the Commonwealth that an offshore wind development might foster.

A series of projects, each of about 400MW, occurring every year, would continuously employ hundreds, in direct jobs, in the construction of the projects. As one project was completed, another would be entering into construction. Because the projects occurred quickly one after another, there would be value to investing in training the local workforce, as opposed to bringing in workers temporarily from outside the area. Because there would be on-going, intense competition for the next project, supply chain companies would have incentive to establish facilities in the area in order to develop competitive advantage over companies which had to provide from facilities located thousands of miles away. This effect would be amplified if investors and supply chain companies had good visibility and high confidence in a consistent schedule of significant projects, one after the other in short order. The number of O&M jobs would exceed over 1000 in about 4-5 years. The economic benefits of these direct jobs to the region would be amplified by indirect employment.

    b. Describe what steps might be taken by a developer to foster such employment and economic development in the Commonwealth.

Vineyard Wind is actively meeting with potential supply chain partners currently to evaluate that question to the best of our ability. Vineyard Wind is committed to seeking ways to maximize local participation and employment to the maximum extent feasible.

    c. What information should be required to demonstrate the local economic development benefits of a project?

We suggest that each developer provide information, with documentation and substantiation, that they think best to demonstrate local economic development benefits.

    d. Should a supply chain plan be required? Please provide reasoning to support your response, including any information that could be required in the supply chain plan?

Bidders should be provided the opportunity to describe their efforts to meet the requirement of the Act to "…where feasible, create and foster employment and economic development in the commonwealth." Bidders should describe their efforts to identify "feasible" opportunities, and how those opportunities would be pursued should the bid be accepted. Any such description should be supported by documentation, such as letters from supply chain companies or economic development agencies or organizations that indicate a good faith effort to evaluate the opportunity.

14. Section 83C requires the DOER to give preference to "proposals that demonstrate a benefit to low-income ratepayers in the Commonwealth without adding cost to the project." Please describe the minimum requirements a bidder should demonstrate to meet this standard.

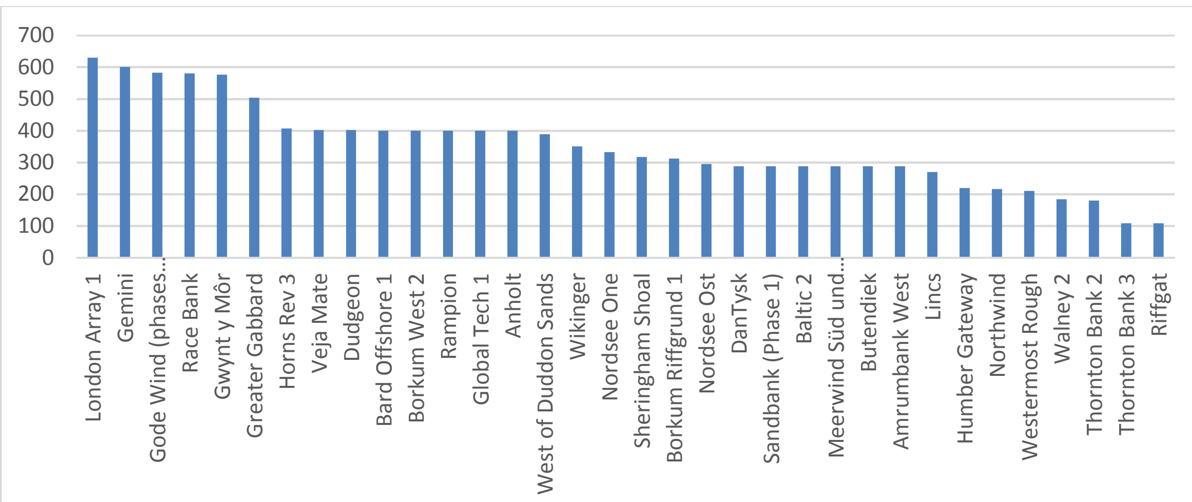
Vineyard Wind requests that the RFP be very clear in its requirements so that bidders can fully understand the minimum requirements and ensure the requirements are being met. Given that this is the only criteria to which 83C requires bids be given preference, it is critical to ensure that the evaluation of this criteria is efficient and transparent.

Appendix A: Analysis of the largest offshore wind farms in operations and under offshore construction in Europe

March 2017

The analysis below is based on a dataset compiled of the 50 largest offshore wind farms in the European market which are either already in operation or with offshore construction underway. The dataset does not include other future planned projects that have not initiated offshore construction or projects that have not yet gone to financial close. Of the 50 offshore wind farms analyzed, 34 of them will have commissioning dates in 2012 or later. The data has been obtained from 4C Offshore database and Wikipedia.

Figure 1 – Largest offshore wind farms in Europe in operation or under offshore construction. Installed capacity in MW.



The largest project to date is London Array 1, with a total installed capacity of 630 MW. The 15 biggest projects have an installed capacity between 400 and 630 MW.

- *An 800MW wind farm would be bigger than any European wind farm in offshore construction or in operation today*

- *An 800MW wind farm would be the second largest in the world before 2020. Hornsea phase 1 would be the biggest with 1200MW (Hornsea 1 is not shown here, as it has not yet gone to offshore construction).*

Figure 2 – Average wind farm sizes in the European markets, showing the 34 offshore wind farms with commissioning dates from 2012 onwards. Depicts installed capacity in MW. Includes projects in operation or under offshore construction.

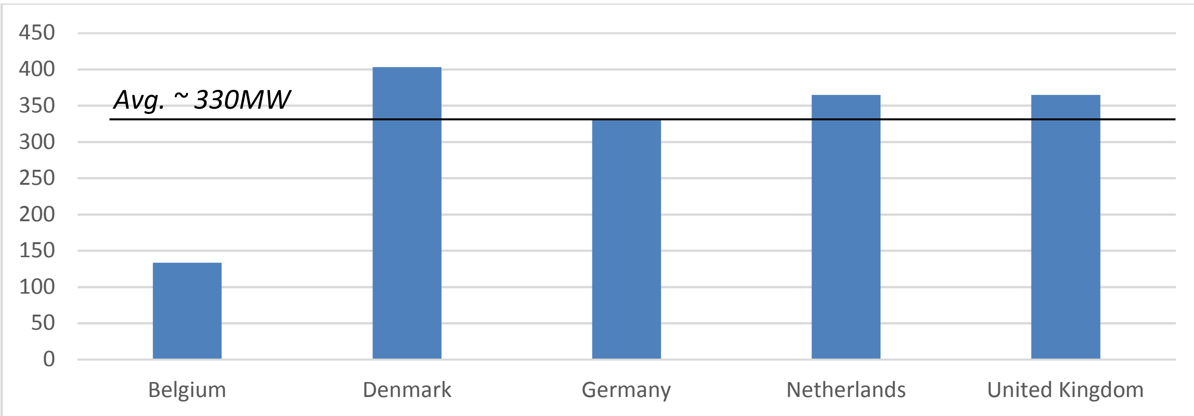
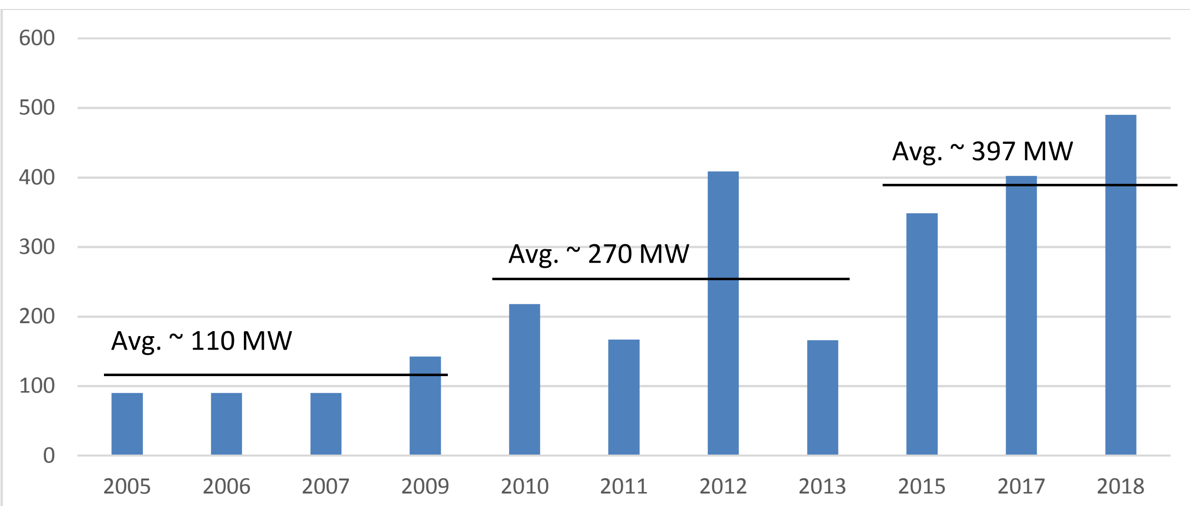


Figure 3 – Illustration of UK offshore wind farm build-out since the start of commercial offshore wind in that country. Average wind farm size per year in MW installed capacity. Includes projects in operation or under offshore construction. Based on wind farm year of commissioning.



- *Early stage average wind farm size (2005-2009) of 110 MW*
- *Second stage average wind farm size (2010-2014) of 270 MW*
- *Latest stage average wind farm size (2015-2018) of 397 MW*

Appendix B: Seasonal wind distribution

Publicly available information show that peak wind speeds and highest wind energy density generally occur during the winter months in the region of the offshore wind lease areas.

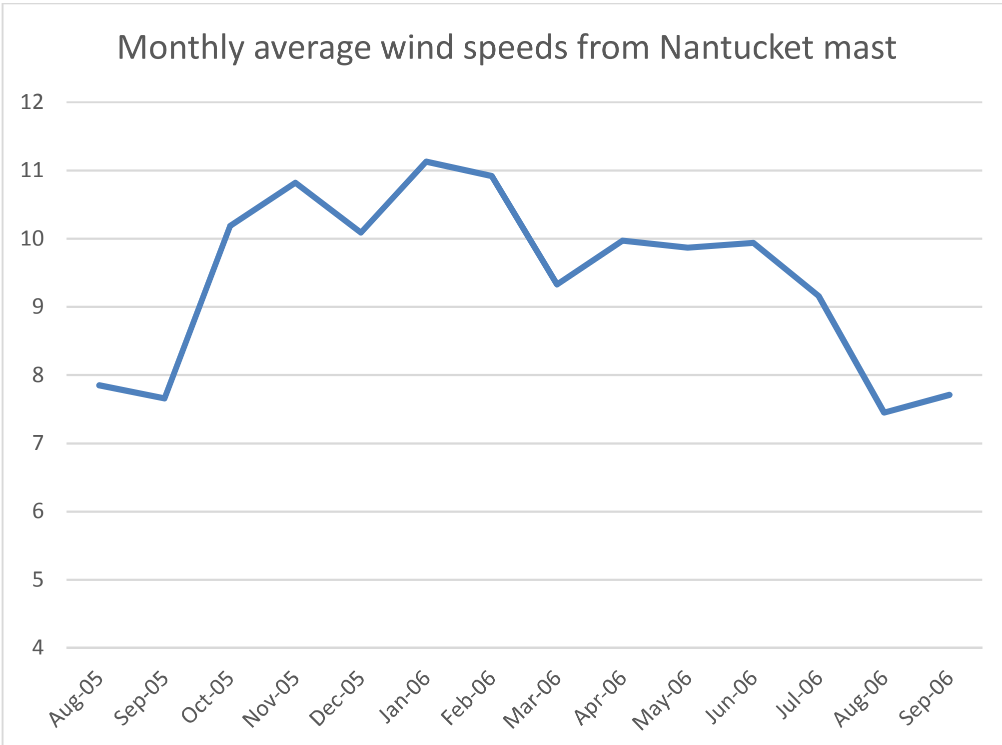


Figure 4 - University of Massachusetts, Wind Energy Center. Wind Resource data "Nantucket, Cape Cod". Data files: Nantucket_0010_2005-07-22_2005-12-31.dat and Nantucket_0010_2006-01-01_2006-10-03.dat. Accompanying report: "WIND DATA REPORT Nantucket, MA July 22nd 2005 to August 31st 2006". https://www.umass.edu/windenergy/resourcedata/Nantucket

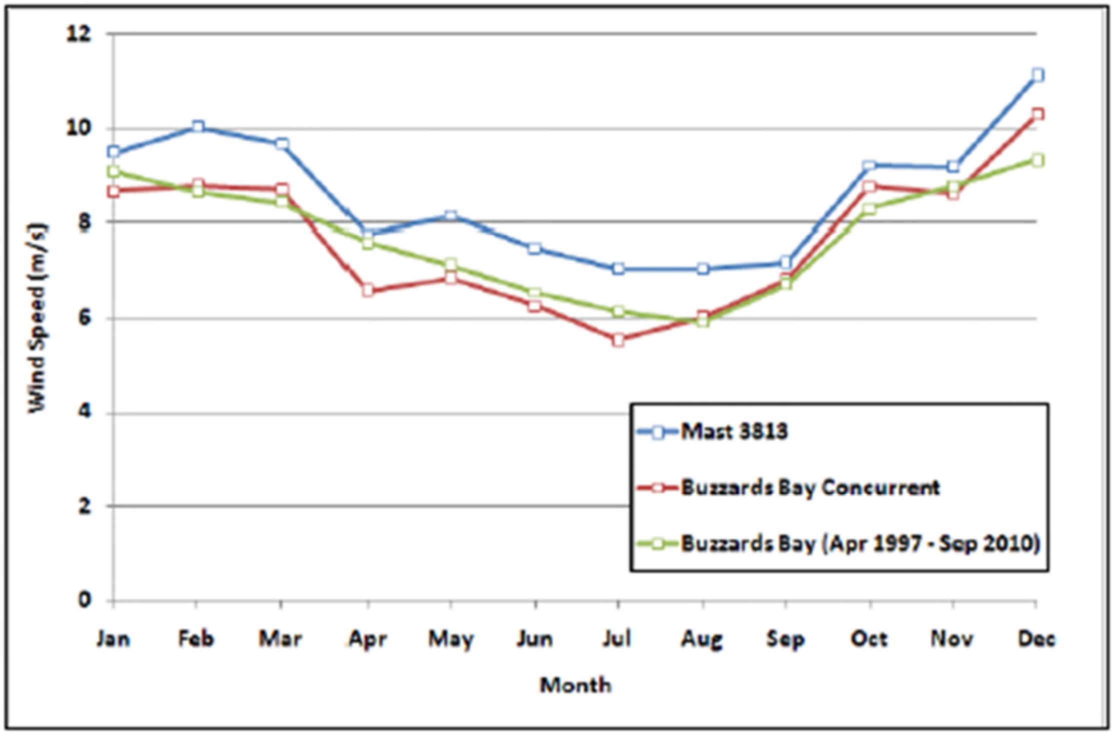


Figure 5 - AWS Truepower. Estimation of the Wind Resource of the Block Island Wind Project (2010-09-27). Downloaded from http://dwwind.com/wp-content/uploads/2014/08/BIWF-Wind-Summary-Report.pdf