



BY EMAIL

March 13, 2017

The Massachusetts Department of Energy Resources  
The Massachusetts Office of the Attorney General  
Fitchburg Gas & Electric Light Company d/b/a 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  
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**RE: 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* Issues for Stakeholder Comment**

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To the Addressees Listed Above:

In response to your March 1, 2017, request for input into the development of a request for proposals (“RFP”) for the competitive solicitation of bids to enter into cost-effective long-term contracts for offshore wind energy generation pursuant to 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 “*Energy Diversity Act*” or “*Act*”), Bay State Wind LLC (“Bay State Wind”) submits the following responses. Bay State Wind is a Delaware limited liability company that holds U.S. Bureau of Ocean Energy Management (“BOEM”) Renewable Energy Lease No. OCS-A 0500, for an area located on the Outer Continental Shelf (“OCS”) offshore Massachusetts where Bay State Wind LLC intends to develop an offshore wind energy installation.

***1. Please provide the following information with your comments:***

- a. Name of Organization*** Bay State Wind LLC
- b. Type of Organization (Public/Industry/Advocacy/Other)*** Industry

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?*

Bay State Wind suggests a due date for the submission of bids that is 90 days from issuance of the solicitation. This will maintain the momentum building in the Commonwealth around the development of an offshore wind industry, and will signal that the Commonwealth intends to implement this landmark procurement in an expeditious manner. The *Energy Diversity Act* was signed into law in August 2016, and developers have been working diligently to advance the status of, and reduce associated development risks concerning, their projects since that time.

Bay State Wind further recommends that the draft RFP be issued on or about May 1. Such a timeframe will afford developers ample lead-time to adjust their development plans to the extent needed to address the priorities and requirements articulated in the draft RFP document. In addition, this schedule will permit bidders to both refine the scope and incorporate the results of studies and analyses conducted during the summer of 2017 on their proposals.

To enhance the solicitation process, Bay State Wind recommends that a form of power purchase agreement (“PPA”) be included in the draft RFP at the time it is submitted to the Department of Public Utilities. An early and meaningful opportunity to review and comment on the draft PPA is particularly important to a successful procurement process, as the offshore wind PPA will necessarily need to include specialized provisions (as potentially compared to a form PPA for the Section 83D procurement) in order to ensure that it appropriately addresses the unique circumstances associated with offshore wind projects. An early resolution of a number of the issues arising out of these circumstances will enhance the prospect of securing cost savings benefits for Massachusetts electricity customers.

This proposed schedule will enhance the prospects for contract award to occur, at least on a provisional basis, in early Spring of 2018, and will encourage the winning bidder to move forward with site development activities during the Spring and Summer of 2018 when ocean conditions are most favorable. Bay State Wind believes that this schedule will help minimize any risk of delays, result in lower project costs, and ensure that the selected project can produce electricity at the lowest possible cost for the benefit of Massachusetts electricity customers.

*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?*

One of the most important considerations in establishing and expanding a local offshore wind industry in the Commonwealth, in the New England region, and in the United States is the ability to establish business foundations that are stable, predictable, and scalable. To these ends, it will be imperative that the Department of Energy Resources (“DOER”) and the Massachusetts electric distribution companies’ (“EDCs”) evaluation team adhere to a solicitation schedule in which each successive solicitation commences not later than 24 months after the prior solicitation. Bay State Wind does not expect any of the relevant market conditions outlined

above to change so materially between bid cycles as to warrant any significant departures from this 24-month cycle.

Bay State Wind further recommends that the Commonwealth develop and announce a comprehensive procurement schedule for the full 1,600 megawatts (“MW”) of capacity. The commitments and investments that offshore developers and supply chain stakeholders make in the Commonwealth will be greater if those developers and stakeholders know that the long-term solicitation process is firm and predictable. This time-certain solicitation schedule will reinforce expectations of market size and timing and, in conjunction with what other states in the region (such as New York) may be contemplating, further encourage regional investment in necessary supply chain industries.

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

As noted above, Bay State Wind believes it is imperative that the Commonwealth establish a solicitation process that is stable, predictable, and scalable. By establishing a comprehensive procurement schedule, the Commonwealth will enable offshore developers and supply chain stakeholders to refine their expectations of market size and timing (with respect to both the Commonwealth and the region), and better determine the scope of regional long-term investment that is necessary to achieve those expectations.

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 400 MW 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 400 MW? If so, why?*

The Commonwealth will benefit from the most competitive bid being brought forward by offshore wind developers. Experience shows that larger projects offer greater cost savings and facilitate more cost-effective bids. As explained further in the response to part d. below, larger projects provide efficiencies of scale, and would be expected to directly result in a lower cost of electricity for Massachusetts electricity customers.

- b. *What considerations should be taken into account in deciding the size of this initial solicitation and, if applicable, the size of future solicitations?*

Section 83C of the *Energy Diversity Act* requires that “individual solicitations shall seek proposals for no less than 400 megawatts of aggregate nameplate capacity of offshore wind energy generation resources” (emphasis added). Thus, Bay State Wind interprets the *Act* to expressly require that the minimum capacity bid shall be no less than 400 MW. This topic was vigorously debated during the legislative process, and the General Court ultimately opted for this minimum bid size. Bay State Wind believes this minimum bid size requirement is essential to achieving the economies of scale necessary to drive cost reduction and to attract the supply chain that will enable further maturation of the Massachusetts offshore wind industry. This

minimum bid size will send a powerful signal to the marketplace that Massachusetts is “open for business.”

However, the first solicitation should also afford flexibility for developers to propose, and for the evaluation team to award, PPAs for projects of greater size. Bay State Wind would suggest a maximum of 800 MW for proposals the initial solicitation. This will provide developers the flexibility to optimize the design of their proposed project without potentially incompatible constraints. Providing this flexibility would enable the evaluation team to consider alternative configurations and the impact such scale economies will have on bid price. Such latitude will surely redound to the benefit of Massachusetts electricity customers. This approach will also reserve 800 MW for future solicitations, the processes for which will benefit from lessons learned from the first solicitation.

Lastly, it should be noted that the Massachusetts RFP process is somewhat unique in that it requires developers to submit bid prices at a relatively early stage in the project development cycle. As such, there is a relatively higher degree of uncertainty compared to European tenders. In light of this, Bay State Wind would propose that developers also be given some latitude to deviate from the amount of capacity bid by a small amount, specifically a bandwidth of +/- 5–10% of the nameplate capacity bid. This flexibility will reduce project development risk, as well as the accompanying risk premium that would otherwise be built into the bid price— results that will again help ensure that that electricity is produced at the lowest possible cost.

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

See response to part d. below.

- d. Recognizing that Section 83C calls for proposals no less than 400 MW 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.*

As noted in the response to part b above, it is Bay State Wind’s interpretation that 400 MW is the minimum bid size allowed pursuant to the express terms of Section 83C. This topic was vigorously debated during the legislative process, and the General Court ultimately opted for this minimum bid size. The Commonwealth is seeking the most cost-effective bids, and it is important to consider the potential economies of scale that can be achieved. Multiple small projects will typically come at a significantly higher cost than larger projects, because the activities required for permitting, development, procurement, construction and operation will be paid for on a multiple basis, eroding the economies of scale enjoyed by a larger project. Preserving bidder flexibility to propose larger scale projects will enable the EDCs and the DOER to secure these significant cost savings for the benefit of Massachusetts electricity customers.

Additionally, if the Commonwealth wants to attract supply chain industries to the state, then it needs to demonstrate that there will be significant scale. Multiple small projects will not produce the kick -start necessary to attract suppliers, which will typically require a minimum contract size, as well as a visible future “pipeline” of projects, to meet the necessary thresholds for establishing capital-intensive manufacturing or assembly facilities. Given the combined activity on the East Coast, a U.S. offshore wind pipeline is indeed emerging. But the scale of the projects in that pipeline needs to be of sufficient size to achieve the best value for ratepayers

and maximize supply chain development. Moreover, a strong “first mover” position for the Commonwealth will be more likely to result in greater economic development opportunities for the Commonwealth.

- 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?*

There is strong interest in offshore wind on the East Coast of the United States. This includes active developments in Rhode Island, New Jersey, New York, Maryland, Delaware, and the Carolinas. It is evident that there is sufficient potential opportunity in all of these states to allow a thriving industry to develop, including with respect to associated supply chain industries. To ensure that the Commonwealth keeps a leading position in this growing market and effectively attracts supply chain industries to the state, the Commonwealth needs to articulate a firm commitment to the development of utility-scale projects.

**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:**

- a. What documentation and information should bidders provide in order to demonstrate the reasonableness of their transmission costs estimates included in their bid?*
- b. Please describe, in detail, how transmission cost risks should be analyzed in the quantitative portion of the bid evaluation.*
- 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?*

As an initial matter, Bay State Wind expects that any project-related transmission facilities (as opposed to New England Independent System Operator (“ISO-NE”) pool transmission facility (“PTF”) upgrades) will—for commercial and permitting reasons—be developed as part of the proposed project (that is, as local generator interconnection facilities), and not as independent transmission facilities). By using this approach, the developer ultimately will be responsible for these costs, and the certainty and reasonableness of cost estimates for interconnection transmission facilities will be a function of a project's progress through the development phase. Projects that are more advanced will likely have identified and mitigated potentially higher impact risks compared to early-stage projects, and will also be in a better position to identify the scope and extent of any PTF upgrades that may be required.

The evaluation team should develop criteria that will assess interconnection costs in a consistent and fair manner. To do so, the evaluation team should consider requesting at least the following information:

- (i) The status and expected receipt date of all necessary siting approvals and permits, the start date of construction, and the projected in-service date of necessary transmission facilities;
- (ii) The expected life of the line, and the amortization period of the transmission line costs;
- (iii) The estimated capital and operations and maintenance costs;

- (iv) A cost estimate that identifies labor, material, and engineering costs for each major cost component of the proposed transmission line;
- (v) Identification of any PTF upgrades likely to be required to qualify for I.3.9 approval and demonstration that such costs are included in the estimate; and
- (vi) A preliminary procurement plan and construction approach.

Bidders should also identify whether transmission cost pricing is fixed, including a comprehensive description of any proposed exceptions to fixed pricing.

In sum, as transmission costs represent approximately 20% of the overall capital cost of an offshore wind development, Bay State Wind suggests that the evaluation team require bidders to provide similar information for the generation portion of the project.

**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?**
- 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?**
- 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)?**
- 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?**
- 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?**

Given that the enabling legislation was promulgated very recently, all proposals are likely to be in the early stages of planning and development at this time. Furthermore, it is unlikely that any project will have completed the ISO-NE interconnection request process at the time bids are due. As such, projects are likely to have a certain degree of cost uncertainty, and it may be a challenge for developers to demonstrate all plans, benefits, and risks associated with an expected interconnection plan at that time.

The evaluation team should strive to treat all bidders fairly, and to establish evaluation criteria that will provide meaningful distinctions among projects based on their ability to mitigate for interconnection risks that could materially impact project costs and/or undermine project viability. Consideration of the following information should allow the evaluation team to assess the relative risks associated with a particular project:

- Status of required interconnection studies and/or approvals;
- Results of any completed feasibility/system impact study, or any study conducted to mimic such analysis done by ISO-NE (including the powerflow study cases and contingencies which are typical of such evaluation);
- Projected I.3.9 approval date, and current status; and
- A deliverability analysis that includes the results of any overlapping impact studies (required for any capacity bid).

It is important for the evaluation process to factor in all of the aforementioned elements when evaluating and determining the viability of a project and the ability of the developer to execute in accordance with its cost proposal.

A cluster interconnection analysis process is being considered by ISO-NE for offshore wind. Bay State Wind does not believe that the factors justifying such studies in northern New England apply to the planned offshore wind solicitation. Moreover, as described in the response to Question 7 below, such an approach will not be likely to benefit Massachusetts electricity customers. In any event, this theoretical approach and related schedule have not been finalized, and their impact on transmission costs and planning remains unclear at this time. Bidders should identify, at the time of the bid, whether their proposal is, or will be, subject to ISO-NE's cluster analysis, and, if so, should describe the impact of such status on cost and/or schedule.

**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?***

Section 83C envisions a competitive bidding process, involving parties holding federal offshore wind energy area leases all vying for the right to secure long-term PPAs. As such, the Act relies upon market forces and competitive discipline as the primary means of securing the lowest-cost and best-value offshore wind resource for Massachusetts electricity customers. Bay State Wind will continue to evaluate additional cost-containment measures for inclusion in its bid response, but does not believe this consultation to be the appropriate forum in which to discuss those measures. In addition, Bay State Wind does not believe it appropriate for the soliciting parties to specify such measures, as this would serve to reduce competitive advantages and differentiation between bidders, to the ultimate detriment of customers.

**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.*

An offshore wind farm consist of five key components: 1) the wind turbines; 2) the array cables that transport the electricity from each turbine; 3) the offshore transformer station that collects the electricity from the array cables and transforms it to a higher voltage to reduce transmission losses; 4) the offshore export cable or generation lead that transports the electricity from the offshore transformer station to shore; and 5) the onshore grid connection point, usually in the form of an onshore transformer station.

In Europe the question of who builds these key components has been approached in two main ways, a “segmented” and a “full scope” approach. In the segmented approach, responsibility for constructing the offshore wind farm and its transmission assets has been split, with developers building the wind farm and the array cables (key components 1 & 2) and transmission system operators (“TSOs”) building the transmission assets (key components 3–5). Examples of the segmented approach include far-from-shore offshore wind generation facilities in Denmark<sup>1</sup> and offshore wind in the Netherlands. In the full scope approach, the offshore wind farm and its transmission assets are viewed as inherent parts of the same infrastructure project, and the developer therefore has the responsibility for financing and constructing all key components up to the onshore grid connection point. The United Kingdom (the world’s largest offshore wind market), as well as nearshore offshore wind in Denmark, successfully apply this “full scope” approach.

Based on lessons learned from the extensive experience of DONG Energy in Europe, Bay State Wind firmly believes that the full scope approach is the most efficient way to deliver lowest-cost electricity to rate payers and ensure that the highest degree of project viability. European experiences show that when developers construct the transmission assets (key components 3–5) they can optimize the technical solutions, project planning, and lifetime of both the generating assets and the transmission assets.

Further, with a full scope approach, a developer can design its offshore wind farm to fit the site, and then design the transmission assets to fit the offshore wind farm. This flexibility to adapt the wind farm to the site during development is an important cost reduction lever. In the segmented approach this lever is largely removed, because a third party Transmission Developer defines the grid connection capacity, thus capping the size of the wind farm irrespective of what would be economically optimal. The reverse is also true, namely that the third party may over-scale the transmission asset compared to the optimal size of the wind farm based on the site. This type of over-scaled transmission asset will result in an unnecessary cost increase to customers while a portion of the capacity of this expensive transmission asset is essentially left idle.

Finally, the full scope approach is the best way to ensure that the entire offshore wind farm (key component 1–5) is subjected to the full competitive force of a solicitation. As the cost of offshore wind falls, and wind farms move further from shore, the transmission assets (components 3–5) are making up an increasingly large share of the total cost. Removing these components from the scope of the developers’ bids excludes them from the purview of the competitive solicitation. This means approximately 20% of a project’s capital cost is not

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<sup>1</sup> In Denmark there are two solicitation regimes for offshore wind. The largest one is for far-from-shore offshore wind, defined as being more than 12 miles away from shore. The other one is for nearshore offshore wind, defined as being 2.5–12 miles away from shore.

exposed to competition, but is instead transferred to a TSO with an effective monopoly on building the transmission assets.

Another advantage of the full scope approach relates to developers' ability to secure economies of scale when purchasing the requisite transmission components, and the leverage that this scale gives them in negotiating prices with the supply chain. As an illustrative example, between 2016 and 2020, DONG Energy will construct roughly 2.7 gigawatts ("GW") of offshore wind with transmission assets, providing significant supplier leverage. In the below answers Bay State Wind will expand on these arguments by providing supporting evidence from Europe.

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

In theory, both the segmented and full scope approaches have advantages. In a segmented approach, the transmission system can be centrally planned and built by a transmission developer using an approach similar to the one taken with the onshore transmission network. This approach allows the offshore transmission network to be "supersized" to accommodate future developments. The main theoretical benefit offered by the segmented approach is that it lowers bidders' development risk by reducing the construction scope. This lower risk should translate into lower risk premiums, and therefore lower cost of electricity.

But these theoretical benefits are difficult to achieve in practice, and are offset by several cost/risk factors that significantly outweigh the purported benefits of the segmented approach. First, it removes competitive pressure from a significant part of the capital cost, which almost certainly leads to higher project costs. In an independent report<sup>2</sup> commissioned by Ofgem, the British gas and electricity markets regulator, it was shown that the U.K. full scope approach had created significant savings for U.K. rate-payers. The report, which focused on the first U.K. tender round between 2009 and 2012, concluded that competition had helped move the industry to the efficiency frontier faster, and that competition had helped create savings of up to \$407 million. For the offshore wind capacity installed in that period, that was equivalent to a universal LCOE reduction of \$6 per megawatt-hour ("MWh").

A second challenge with the segmented approach is highlighted by the first eight German wind farm developments. Transmission delays led to offshore wind farms being stranded without grid connection for up to two years, as the TSO was unable to deliver this crucial infrastructure on time. These delays led to substantial compensation payments being made to the affected developers: between 2013 and 2015, the TSO paid out more than \$2 billion in compensation.<sup>3</sup> These payments were funded by an extra levy on ratepayers. It is possible to shield ratepayers from unforeseen compensation payments by ensuring that TSOs are not liable for cost overruns caused by delays. In such a system, however, developers would either exit the market due to unacceptable risks, and thereby lower competitive pressure, or increase their risk premiums. Both of these options would result in higher bid prices. A report by the Hertie School of Governance<sup>4</sup> on Germany's experience with its first eight offshore wind farms concluded that managing the interface between these two complex and interdependent, but separately-led, processes proved to be a challenge for the TSO, and was a key source of delays, because it

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<sup>2</sup> CEPA/BDO, *Evaluation of Offshore Transmission Tender Round 1 Benefits* (2014).

<sup>3</sup> Hertie School of Governance, *Offshore Wind Power Expansion in Germany* (2015).

<sup>4</sup> *Id.*

unnecessarily increased complexity and failed to allocate risk to the players best able to handle it.

It is worth noting that delays like this are unheard of in the United Kingdom, where developers are responsible for designing and constructing the transmission assets. Indeed, in the United Kingdom developers have, under the full scope system, successfully connected more than 5,100 MW of offshore wind to the grid. This work requires proactive close coordination and dialogue between developers and the authorities, work to which offshore wind developers are accustomed. In the United Kingdom, developers are in close dialogue with the authorities regarding grid connection points, as well as onshore and offshore spatial planning and permitting, and also engage extensively with local stakeholders to ensure local support. This work is very similar to the extensive permitting and stakeholder engagement in which developers engage for the offshore wind farms themselves.

In Denmark, where the segmented approach is also practiced for far-from-shore offshore wind projects, the authorities seek to avoid costly delays by building the transmission assets a long time in advance. This Danish low-risk approach is not possible in Massachusetts, because the Transmission Developer would already need to have been several years into developing the transmission assets at this stage of the Section 83C RFP. To illustrate, consider the Horns Rev 3 offshore wind farm, which is expected to be commissioned in 2019 in the Danish North Sea. The Danish TSO began development work on the transmission assets in April 2012, and completed construction in fall 2016. Even if this approach could be used in later solicitations in Massachusetts it has several significant drawbacks. First, the approach is only possible because the authorities determine the size of the wind farm, meaning that developers are unable to optimize the wind farm to the site or the transmission solution. This limit on flexibility removes an important cost-reduction lever. Second, this approach creates potentially large opportunity costs, because transmission assets stand idle for years; these costs would be borne by electricity customers.

In Massachusetts, the segmented approach raises a number of other challenges. The first relates to uncertainty over the Federal Energy Regulatory Commission (“FERC”) regulations governing a separately owned transmission network. Any transmission service arrangements under a segmented approach will need separate FERC authorization, which would likely add substantive complexity. (A generator-owned lead line under a full scope approach will not require a similar level of FERC approval.) Another potential complexity of the segmented approach is cost recovery in a scenario where the transmission asset is super-sized to accommodate future development. Under FERC regulations, costs begin to be billed to customers as soon as construction is complete. This means customers could begin paying costs associated with wind farms that do not yet exist, and may not exist for many years.

Bay State Wind recommends that Massachusetts adopt the full scope approach, and not require additional bids based on an assumption of interconnection at an off-shore backbone system developed by a third party. This approach keeps the solicitation simple, and allocates risk where it is best handled. Further, the full scope approach allows the design of the transmission network to follow the needs of the offshore wind farm and not vice versa. Finally, the full scope approach ensures that competitive pressure is applied to all assets from the wind farm up to the onshore interconnection point.

- 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.*

See response to part b. above.

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

See responses to parts e. and f. below.

- 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.*
  - 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.*
  - 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.*
  - 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.*
- 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?*

Based on the European experiences presented above, Bay State Wind would respectfully disagree with the overall premise of part e., and would recommend against implementing a segmented approach in Massachusetts. Further, Bay State Wind notes that it has not seen any detailed proposals for how a segmented approach could be implemented in Massachusetts. If the DOER and the EDCs nevertheless adopt a segmented approach, there are—within the statutory constraints—four main options for how this could be implemented. All four options would disadvantage Massachusetts electricity customers because they increase risk, reduce competition, or do both.

### Option 1 – a 1,600 MW HVDC transmission asset

One way to implement the segmented approach would be for a transmission developer to build a single transmission asset that could accommodate the entire state target of 1,600MW of offshore wind. Only HVDC technology supports a transmission asset of that size.<sup>5</sup> The main problem with this approach is that the required HVDC technology is largely untested offshore, and highly complex. Offshore wind farms in Germany used simpler point-to-point HVDC technology, and faced technical challenges and delays. Similar lengthy delays would be likely with a single 1,600 MW HVDC transmission asset. And given the novelty of the technology (a shared offshore HVDC grid with several offshore wind farms connecting to a single offshore substation has never been built), the risk might be un-insurable, meaning it would have to be borne by the transmission developer. All of this creates the risk of significant and costly delays (paid for either through direct compensation or through the developer's high risk premiums).

The theoretical economies of scale benefits of a shared HVDC grid should be compared to its large opportunity costs and potential sunk costs. A 1,600 MW HVDC transmission asset would carry an up-front price of several billion dollars. Indeed, given the high-risk nature of the asset, it would likely be un-financeable by third party debt providers, leading to very expensive cost-of-capital for the transmission developer, and further increasing costs. Moreover, given that the offshore wind farms connecting to it would be built gradually, a large share of the capacity of the transmission asset would stand idle for years. Depending on the size and location of the wind farms ultimately built, a share of the transmission asset might never be used. Even with roughly 12,000 MW of offshore wind in the North Sea, a shared HVDC grid has been rejected given the unclear benefits and substantial risks.<sup>6</sup>

Finally, connecting all of the Commonwealth's 1,600 MW of offshore wind to the onshore grid through a single HVDC export cable carries a large risk in case of a cable outage. In sum the many and substantial risks associated with this approach should rule it out.

### Option 2 – HVAC transmission overcapacity

It is estimated that each of the three current offshore wind leases on the OCS offshore of Massachusetts can accommodate between 1000 MW and 2000 MW of offshore wind generation. To ensure competition between the sites, and avoid costly grid delays the Transmission Developer could build out more transmission capacity for each site than is called for by any initial solicitation. Such an approach, however, would lead to a large and expensive overcapacity, the cost of which would ultimately be borne by Massachusetts electricity customers, without any corresponding return on that investment until some uncertain future date. While such an approach would take into account the long lead times of transmission assets, Bay State Wind contends that this is an unattractive and largely unrealistic option.

### Option 3 – Competition undermined

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<sup>5</sup> Offshore HVAC cables cannot efficiently or safely go much above a 400 MW capacity (exact limit depends on voltage and length of cables), which means that a transmission developer could not economically build a single shared HVAC transmission asset for the cumulative 1,600 MW of offshore wind planned in Massachusetts.

<sup>6</sup> In a study by Nordic TSOs it was found that a shared offshore grid's cost savings and interconnection level were similar to those of a point-to-point grid. See FINGRID, LANDSNET, SVENSKA KRAFTNÄT, Statnett, Energinet.dk, *Nordic Grid Development Plan 2014* (2014).

To avoid the large sunk costs of option 2, and to minimize the risk of grid connection delays, the transmission developer could build a 1,600 MW HVAC transmission asset spread across the three lease areas (roughly 530 MW per lease). This would help remove the risk of delays, and help ensure that each developer could connect its allotted share to the grid. But it would lead to a suboptimal use of the sites, because developers would be forced to fit their wind farms to the grid specifications. Worse, it would weaken competitive pressure by giving tacit project approval of 530MW for all developers. This lack of competition could significantly raise the price of the bids received, and should therefore be avoided.

#### Option 4 – High risk approach

In the last option, the transmission developer could build the transmission asset step-wise as the result of each solicitation becomes known, allowing it to match the transmission asset exactly to the size of the winning offshore wind project. As highlighted by the German experiences described above, however, this would drastically increase the chance of offshore wind farms' being stranded without a grid connection, and would therefore result in developers' increasing their risk premiums. While option 4 would likely increase the cost of offshore wind in the Commonwealth—to the detriment of electricity customers—it would appear to be the best of these four very much sub-optimal approaches, if the DOER and the EDCs decide to proceed with the segmented development approach.

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?*

The construction timeline for an offshore wind facility is dependent on a number of factors, including permitting, project size, equipment procurement, actual construction, and phasing of commissioning.

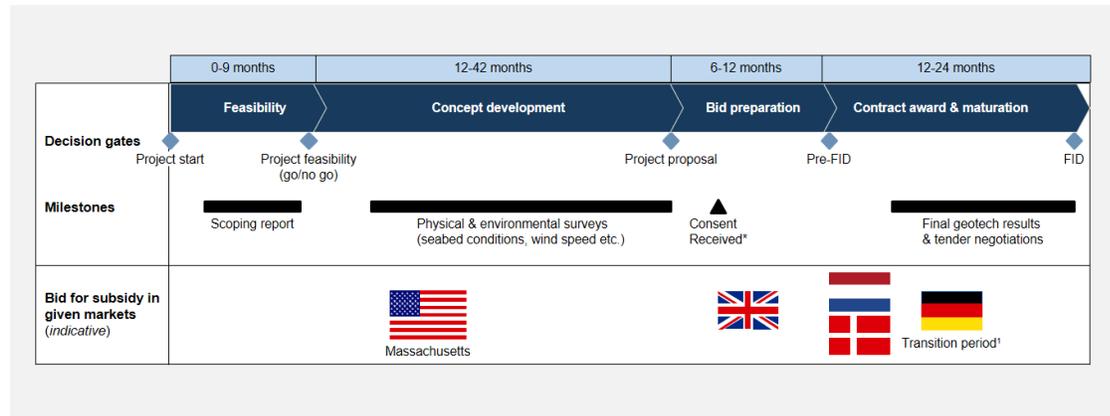
Bay State Wind notes that the permitting structures (both in terms of regulations and actual experience) for offshore wind facilities in Europe are more defined than they are in the United States, and that the supply chain similarly is more developed. For example, the permitting process established by BOEM for projects located in the federally-controlled OCS—applicable to all three Massachusetts wind energy areas—has not yet been applied to a large-scale offshore wind facility. As such, it is difficult for any developer to predict how long it may take for BOEM to review and issue approvals for proposed Site Assessment Plans (SAPs) and Construction and Operation Plans (COPs), as well as to conduct and complete required reviews under the National Environmental Policy Act, Endangered Species Act, and similar environmental statutes, and how these timelines might change in the context of a phased development approach for a larger scale project.<sup>7</sup> State and local permitting for the generation lead can also take substantial time.

A further complication is that, unlike European program tenders, where much of the predevelopment activity (environmental studies, detailed geophysical and geotechnical studies)

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<sup>7</sup> For a graphical depiction of the typical timeline of planning and identification, leasing, site assessment and construction related to a wind energy area in federal waters subject to BOEM jurisdiction, see <https://www.boem.gov/Commercial-Leasing-Process-Fact-Sheet/>.

is carried out prior to bid submission, in Massachusetts the winning bidder will have to undertake significant development work after the solicitation, as illustrated in the figure below. Thus, it is extremely difficult to directly estimate a reasonably-expected in-service date from the point in time a PPA is executed by reference to the offshore wind industry’s experience in Europe.



In light of the above, Bay State Wind respectfully suggests that the DOER and the EDCs establish—consistent with the provisions of Section 83C—a “commercially reasonable” timeframe for project completion based on a reasonable estimate of the duration required to navigate critical path federal permitting milestones (e.g., SAP, COP). Given the financing and carrying costs associated with developing a large scale offshore wind facility, any successful developer will be incentivized to develop its projects in as timely a manner as possible. While a developer may then propose to deviate from the in-service date, the basis of any assumptions and reasoning behind a developer’s proposal to deviate (especially in the case of an earlier date) should be carefully examined to determine if they are reasonable given the uncertainties referenced above.

***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.***

Bay State Wind respectfully suggests that a developer’s proposed commercial operation date should be one, but not the only, factor that should be considered in evaluating proposals. As noted above, given the uncertainties associated with the regulatory timeline, the DOER and the EDCs must consider whether a proposed commercial operation date is realistic, or instead is overly optimistic. Even where each developer uses realistic assumptions, the in-service dates for different proposals may differ based on the project size and proposed technology that will be used. Other factors—such as pricing, LCOE, ability to finance, likelihood of meeting the in-service date—also should be given their proper weight in the evaluation process. In the end, the goal of Section 83C is to ensure that the “best” project is timely and successfully developed, and produces the lowest possible price of electricity for Massachusetts customers.

Bay State Wind would also argue against a firm commercial operation date, backed by penalties, given the uncertainties surrounding the permitting process. Until these processes become more routine and predictable, any attempt to impose performance penalties will carry a risk premium, and will not be in the long-term interest of Massachusetts customers.

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

Bidders should be required to provide a detailed development plan which incorporates timelines for siting, permitting, regulatory approvals, and construction.

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

As noted above, bidders should be required to provide a detailed development plan that addresses these issues, as well as all other factors that may be relevant to the timeline and ability to successfully develop the proposed project.

- 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?*

Offshore leases issued by BOEM allow the lessee to request an easement in federal waters for the construction of any necessary transmission lines. In State waters, the easement process is governed by the provisions of M.G.L. ch. 91. As such, issues associated with “site control”—which typically arise in the context of an on-shore transmission line (or even an independent offshore transmission line)—would not arise. Notwithstanding this point, Bay State Wind believes that bidders should be required to provide detailed information on the potential route(s) for any associated transmission lines, as well as potential points of interconnection with the regional electric grid.

- 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?*

Bay State Wind respectfully submits that no additional information—beyond what is required on bid parameters and pricing—is necessary in order to make this comparison across bid rounds. Perhaps this topic could be revisited at the time of future solicitations pursuant to Section 83C.

- 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?**

Natural gas pipeline constraints have resulted in periodic run-ups in delivered gas prices, causing wholesale energy prices in Massachusetts and New England more generally to spike, sometimes dramatically, during cold snaps. This dynamic was apparent during the Polar Vortex in January and February 2014, when ISO-NE and neighboring regional transmission organizations saw wholesale prices soar, costing ratepayers many billions of dollars throughout

the New England, New York and PJM regions. There have been significant limitations on gas deliveries to combined cycle plants and peakers directly connected to Algonquin and Tennessee in southeastern Massachusetts and Rhode Island (“SEMA/RI”), and elsewhere in New England, due to full pipeline utilization during the winter.

As a general matter, offshore wind’s high production profile during the peak winter heating season will temper the run-up in electricity prices by reducing the need for thermal generation in the SEMA/RI zone. This displacement will help reduce New England electricity customers’ exposure from adverse wholesale electric price spikes by displacing the need to run more costly coal and oil-fired generation due to full utilization of the Algonquin and Tennessee pipelines. An experienced operator with a demonstrable record will be best positioned to ensure wind turbine availability during such a critical period. While Bay State Wind suggests that bidders be required to provide monthly production estimates to facilitate the evaluation team’s assessment of the expected displacement of thermal generation, given the nature of offshore wind resources, Bay State Wind does not believe that the imposition of liquidated damages for any failure to meet these estimates is appropriate or necessary.

***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?***

Bay State Wind notes that the reference to storage under Section 83C enables offshore wind projects paired with energy storage systems to participate in the bidding process. In other words, the quoted Section 83C language concerns the threshold eligibility of storage-paired projects in an offshore wind solicitation, i.e., it says that such projects should be “allow[ed]”.

Bay State Wind is supportive of the deployment of storage systems in conjunction with offshore wind facilities, but does not support incorporating a quantitative evaluation of the benefits of nascent energy storage in ISO-NE markets (i.e., energy and ancillary services markets) in this solicitation. The methodology for quantifying the full benefits of projects that deploy storage continues to evolve; both the FERC and ISO-NE are currently considering how to fully monetize the value of these resources.

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

No comment.

- 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?***

Enabling storage to participate in all markets will likely ensure the highest system impact, while securing a cost-effective case for the developer.

**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.**

***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?***

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

All offshore wind energy areas are currently in early stages of permitting pursuant to the comprehensive federal and state environmental regulatory processes designed to ensure that offshore wind development occurs in a manner consistent with principles of environmental stewardship. These processes are designed to identify, at an early juncture, potential impacts on the human, biological and physical environment and to elicit a thorough consideration of strategies for mitigating any potential impacts.

Thus, while it is premature at the stage developers will be submitting bids to inventory these potential impacts, it should be incumbent upon developers to describe their respective approaches to characterizing and addressing these environmental considerations as part of their pre-development efforts. Further, evaluation of environmental qualifications should include the following:

- Has the developer demonstrated a track record of successful environmental impact assessment in the permitting of large utility-scale projects, and of implementation of appropriate and effective mitigation measures?
- Has the developer described how it is adopting best practice management, any guidelines provided by regulators, and lessons learned and their application to site characterization?
- Has the developer documented robust communications and stakeholder engagement plans (thereby showing how it has successfully addressed stakeholder concerns)?

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

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

While Bay State Wind fully supports the goal of establishing a robust, Massachusetts-based supply chain, it does not believe a supply chain mandate to be the most efficient or effective way to achieve this goal. In Bay State Wind's view, timely implementation of the full 1,600 MW procurement for offshore wind, in concert with similar state-sanctioned procurements across the region, is the most important step the Commonwealth can take to foster economic development opportunities around the emergent U.S.- based offshore wind industry. This megawatt-specific, time-certain project pipeline sends a powerful signal to manufacturers, vendors, and service providers alike that there is the potential for continuous work in this field for some time to come, and that there will be a reasonable opportunity to recoup the significant investment in infrastructure, inventory, and personnel that is necessary to establish a robust local business presence.

This is borne out by DONG Energy's experience in the United Kingdom. DONG Energy estimates that approximately 45% of the economic value of its 1,200 MW Hornsea project, which is scheduled for commercial operation in 2020, will derive from local U.K content. This level of local commitment did not happen overnight; nor was it a result of a governmental mandate. Rather, it reflects the steady progression of industrial development that originates in growing market demand, and is supported by the competitive advantages enjoyed by certain regions to support elements of the offshore wind value chain. Southeastern Massachusetts enjoys all the attributes that will facilitate the successful development of a strong and diverse supply chain.

Bay State Wind notes that the *Act* establishes, as one factor in bid/resource selection, that the project "create and foster employment and economic development in the commonwealth." Thus, Bay State Wind would fully expect the solicitation to rank more favorably those projects that take advantage of opportunities for local participation in the offshore wind project. This should provide sufficient motivation for developers to target and prioritize local opportunities where they make economic sense, even in the absence of an explicit local content mandate.

It should be acknowledged that, for the first offshore wind projects in Massachusetts, any local content requirement will likely entail a cost premium. Thus, there may be an inherent tension between the objective of cost minimization and limiting customer exposure, on the one hand, and the objective of maximizing the use of local industry and labor, on the other. Bay State Wind believes that this tension is best sorted out in the competitive marketplace rather than through the imposition of potentially onerous requirements at this very early juncture in the U.S. offshore wind industry's maturation. Imposition of content requirements that are overly ambitious runs the risk of stalling the industry before it gains momentum, or of chilling stakeholder enthusiasm by making the initial projects more expensive than necessary.

The Commonwealth can and should play a constructive role in the development of an OSW economic ecosystem. Tax credits, training programs, and other economic development incentives to encourage offshore wind-based industries to take root in the Commonwealth are all complementary policies to grow the local offshore wind economy. Bay State Wind supports these as worthwhile measures that the Commonwealth can take to make itself an attractive U.S. home to prospective suppliers. DONG Energy regularly works with governments, communities,

and trade groups to advance the offshore wind industry, and Bay State Wind committed to a similar approach in the enthusiastic Massachusetts market.

***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.***

Section 83C envisions a scoring adder or other bid advantage where the proposal includes a measure or measures that promote the interests of low-income ratepayers, without shifting the costs for such measure or measures to remaining ratepayers. Thus, developers should be asked to quantify the benefit conferred, while also demonstrating how the source of funding or other benefit passed is external to the purchased price of electricity and/or renewable energy credits. Beyond this, Bay State Wind respectfully urges the DOER to leave decisions regarding, among other things, the nature, scope, level, and duration of low-income ratepayer benefits to the bid participants, because any prescription will serve to limit bidder creativity and differentiation in meeting this objective.

Very truly yours,



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Fred Zalczman

On behalf of Bay State Wind

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