Study on Long-Term Contracting Under Section 83 of the Green Communities Act

Submitted to

Massachusetts Department of Energy Resources

December 31, 2012

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I. Introduction and Executive Summary

Under Section 83 of the Green Communities Act ("GCA"), Chapter 169 of the Acts of 2008, the Commonwealth's electric distribution companies ("Distribution Companies") were required, after consultation with the Department of Energy Resources ("DOER"), to solicit proposals from developers of renewable energy projects and to execute long-term power purchase agreements ("PPAs") for energy and/or renewable energy certificates ("RECs") in order to facilitate the development, financing, and construction of these projects, subject to the approval of the PPAs by the Department of Public Utilities ("Department" or "DPU"). The Distribution Companies, in consultation with DOER, issued a Request for Proposal ("RFP"), which ultimately resulted in the execution by three Distribution Companies of five PPAs for approximately 150 MW of generation for new renewable energy projects, which were then approved by the Department.[1] Separately, National Grid[2] received authorization from the Department to negotiate a PPA with Cape Wind Associates, LLC ("Cape Wind")[3] which was subsequently executed and approved by the Department.[4]

In August 2012, Governor Patrick signed into law Chapter 209 of the Acts of 2012, An Act Relative to Competitively Priced Electricity in the Commonwealth ("Chapter 209"). Under Section 36 of Chapter 209, a new and expanded version of Section 83 was enacted, Section 83A, which increases the number of solicitations the Distribution Companies are required to conduct, beginning on January 1, 2013, and modifies the procurement process in various respects.

The solicitation process under Section 83A, however, cannot take effect until DOER has "completed a study to assess whether the long-term contracting requirements

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1 **NSTAR Electric Company**, D.P.U. 11-05, 11-06, 11-07 (August 19, 2011), **Western Massachusetts Electric Company**, D.P.U. 11-12 (October 7, 2011), **Fitchburg Gas and Electric Company, d/b/a Unitil**, D.P.U. 11-30 (December 7, 2011).

2 Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid.

3 **National Grid**, D.P.U. 09-138 (December 29, 2009).

4 **National Grid**, D.P.U. 10-154 (November 22, 2010).

reasonably support the renewable energy goals of the commonwealth as required under section 83 of chapter 169 of the acts of 2008 and said study has been submitted to the clerks of the house of representatives and the senate and to the chairs of the joint committee on telecommunications, utilities and energy." Moreover, "[t]he study shall include, but not be limited to, input from stakeholders in the energy sector." The requirement for a study is similar to the assessment required in Section 83 of the GCA as to "whether the requirements set forth in this section reasonably support the renewable energy goals of the commonwealth as set forth in said section 11F of said chapter 25A," the Massachusetts Renewable Portfolio Standard ("RPS"). The purpose of this report is to fulfill these requirements.

Following the passage of Chapter 209, DOER sought competitive bids from consultants to prepare the study. Peregrine Energy Group, Inc. ("Peregrine"), in conjunction with New Energy Opportunities, Inc. ("New Energy Opportunities" or "NEO"), submitted a proposal, and was subsequently awarded the contract, to conduct the study.[5]

This report is organized as follows:

- Section II summarizes the statutory and regulatory support for the solicitations conducted under Section 83, the solicitations and resulting PPAs, and the current status of the projects for which the 83 contracts were executed;
- Section III provides an assessment of the role of Section 83 PPAs in meeting Massachusetts RPS goals; and
- Section IV assesses the reasonableness of the implementation of Section 83 with suggestions for future improvements.

In the course of preparing this report, Peregrine and NEO interviewed representatives of 23 companies and organizations in order to obtain input from stakeholders in the energy sector. Interviewees included representatives from the four Distribution Companies who conducted solicitations under Section 83,[6] 11 renewable energy developers who participated in the Section 83 solicitations, five organizational stakeholders—the Associated Industries of Massachusetts ("AIM"), Conservation Law

[5] The qualifications of Peregrine and New Energy Opportunities, including the consultants primarily responsible for authoring this report, are summarized in Appendix A to this report.

[6] Since the solicitations were conducted, two of the Distribution Companies, NSTAR Electric Company and Western Massachusetts Electric Company, are now under common ownership as the result of the Northeast Utilities/NSTAR merger.

Foundation ("CLF"), New England Clean Energy Council, New England Power Generators Association ("NEPGA") and the Solar Energy Industries Association, financial investors (a renewable energy lender and a tax equity provider), and Robert Grace, President of Sustainable Energy Advantage, LLC, a renewable energy market analyst.

Of the five projects which received PPAs from the RFP process, four projects (three wind and one hydroelectric) have either been built or are in construction. The developers of these projects have stated publicly and in the interviews conducted that the PPAs executed with the Distribution Companies were critically important in their ability to finance and build their projects. Cape Wind, which also has signed a PPA with NSTAR Electric Company ("NSTAR"), has publicly stated that the two contracts should enable it to obtain financing for its project.

Based on the interviews conducted, our review of the solicitations, and our knowledge of the electric power industry, our major conclusions are as follows:

- Long-term contracts for energy and RECs are, and will be, necessary for Massachusetts to meet the goals under its RPS with respect to Class I Renewable Generating Units;
- There are an insufficient number of creditworthy entities willing to enter into long-term contracts with renewable energy developers for multi-MW grid-connected projects in the absence of a mandate on the Distribution Companies to do so;
- The long-term contracting requirements under Section 83 reasonably fulfill the need for long-term contracts and reasonably support the renewable energy goals of the commonwealth;
- There was a general consensus that the RFP process employed under Section 83 was, for the most part, well conducted, fair and produced good results;
- There were a few shortcomings in the solicitation process under Section 83, which can, and are likely to be, rectified in future Section 83A solicitations, because of modifications to future solicitation processes mandated by Section 83A and as a result of "lessons learned" from the Section 83 procurements.

The starting point for our assessment is an overview of the Massachusetts RPS, Section 83, the solicitations conducted under Section 83, and the new Section 83A.

II. Background: The Massachusetts RPS, Long-Term Contracting Policies and the History of the Section 83 Solicitations

A. The Massachusetts Renewable Portfolio Standard: Class I

Under the Massachusetts Renewable Portfolio Standard, all retail electric suppliers, including the Distribution Companies in their role as standard offer service providers, are required to purchase RECs from Class I renewable energy generating resources in an increasing amount each year—from seven percent in 2012 increasing one percent each year thereafter as a percentage of total sales to 10 percent in 2015 and 15% in 2020. Class I renewable energy resources include wind, small hydro, and other defined renewable generating resources that began commercial operation after December 31, 1997. Under DOER's regulations, these "new" facilities (post-1997) include the energy associated with expansions of existing facilities.[7] Geographically, a qualifying Class I Renewable Generating Unit may be located in the ISO-New England control area or in an adjoining control area (New York, Atlantic Canada and northern Maine, and Quebec). Facilities located in an adjoining control area are subject to special energy delivery and other requirements.[8] Under DOER regulations, the retail electric suppliers are required to document the required amount of Class I Renewable Generation Attributes through certificates issued by the NEPOOL Generation Information System for electric energy produced by qualifying Class I Renewable Generation Units, with one MWh of energy produced by one Class I Renewable Generation Unit correlating to one REC.

Retail electric suppliers are also required to purchase a percentage—specified by DOER—of their sales from distributed solar photovoltaic ("solar PV") generation sited in the Commonwealth—the "Solar Carve Out" requirement.[9] The solicitations conducted under

[7] 225 CMR 14.05(2).

[8] 225 CMR 14.05(5).

[9] This obligation to purchase solar renewable energy certificates is carved out of the obligation to purchase Class I RECs. There are also separate requirements for retail electric suppliers to purchase (a) Class II RECs from existing renewable resources built on or before December 31, 1997—Class II RPS resources—and (b) Alternative Electric Certificates from certain non-renewable alternative resources, such as combined heat and power, under the Alternative Electric Portfolio Standard, Section 11F1/2 of Chapter 25A.

Section 83 which are the subject of this report, however, focused on energy and RECs from Class I Renewable Generating Units with a minimum size of 1 MW.[10]

If a retail electric supplier does not have access to sufficient amounts of Class I RECs, the supplier may instead make an Alternative Compliance Payment ("ACP"). The ACP Rate for RPS Class I is $50 per MWh in 2003, adjusted with inflation. In 2012, the ACP Rate is $64.02/MWh. Class I REC prices have moved up and down over the past 8-9 years and have increased sharply in the past year, now in the range of $60—close to the ACP.

The Massachusetts Class I RPS market is part of a larger market for RECs from new renewable generation projects. Four of the five other New England states have their own Renewable Portfolio Standards with categories for renewable generation that are somewhat similar to, although different from, the Massachusetts RPS Class I.[11] Each state's RPS statute and regulations define the RPS eligibility of generation a bit differently, and the definitions can change over time.

The recent increase in Massachusetts Class I REC prices have primarily been due to the challenge in financing and building new renewable generation to keep up with the increasing demand for Massachusetts Class I RECs. The recognition of this challenge led to the Massachusetts General Court's passage of Section 83 of the GCA in 2008.

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[10] This report focuses on the solicitations conducted under Section 83 during 2009-2011. Subsequently, NSTAR conducted a RFP for S-RECs from approximately 5 MW of eligible solar project capacity, http://www.nstar.com/business/energy_supplier/supply_renewable_contracts.asp, but that RFP is addressed in this report in the context of issues raised with respect to the 2009-2011 Section 83 solicitations.

[11] Rhode Island has a Renewable Energy Standard for post-December 1997 renewable energy resources, http://www.ripuc.ri.gov/utilityinfo/RESRules(7-25-07).pdf; New Hampshire has a Class I renewable energy standard for renewable energy resources built after January 2006, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NH09R%20%20; Connecticut Class I has similar technologies to Massachusetts Class I, but no vintage requirement and an emissions rate requirement for biomass, http://www.ct.gov/pura/cwp/view.asp?a=3354&q=415186; Maine's Class I RPS is for new renewable energy resources built, expanded or refurbished after September 1, 2005, but with fewer restrictions on biomass eligibility, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=ME01R.

B. Section 83 of the GCA and the Department's Regulations

Section 83 of the GCA required the Commonwealth's investor-owned electric distribution companies to "solicit proposals from renewable energy developers and, provided reasonable proposals have been received, enter into cost-effective long-term contracts to facilitate the financing of renewable energy generation ...." Distribution companies were required to solicit proposals twice during a five-year period for energy and/or RECs. They were not required to purchase more than three percent of their total distribution demand. The distribution companies were required to consult with DOER regarding the "timetable and method for solicitation and execution of such contracts" and to submit and obtain approval from the DPU with respect to such timetable and solicitation method. Contracts could be 10 to 15 years in duration.

There was considerable flexibility as to how the Distribution Companies could satisfy their obligations under Section 83, "which may include public solicitations, individual negotiations or other methods." Distribution companies, however, were required to consult with DOER regarding their choice of contracting methods and solicitation methods. All executed contracts were subject to DPU approval.

The statute provided that eligible renewable energy facilities must be located in Massachusetts or adjacent federal waters. However, Section 83 also provided:

> If any provision of this section is subject to a judicial challenge, the department of public utilities may suspend the applicability of the challenged provision during the pendency of the judicial action until final resolution of the challenge and any appeals, and shall issue such orders and take such other actions as are necessary to ensure that the provisions that are not challenged are implemented expeditiously to achieve the public purposes of this provision.

Section 83 set forth the requirements to be applied by the DPU in its review of any contracts submitted for approval. Any renewable energy project which would be the source of supply must:

- have a commercial operation date on or after January 1, 2008;
- be qualified by DOER as eligible to participate in the RPS program;
- be determined by the DPU to:
  - provide enhanced electricity reliability within the commonwealth;
  - contribute to moderating system peak load requirements;

- be cost effective to Massachusetts electric ratepayers over the term of the contract; and
- where feasible, create additional employment in the Commonwealth.

The DPU was directed to "take into consideration both the potential costs and benefits of such contracts, and shall approve a contract only upon a finding that it is a cost effective mechanism for procuring renewable energy on a long-term basis." Distribution companies that enter into power purchase agreements approved by the DPU were entitled to remuneration of "4 per cent of the annual payments under the contract to compensate the company for accepting the financial obligation of the long-term contract."[12]

In comments filed to the DPU, DOER proposed to develop a statewide procurement under Section 83, with the assistance of consultants it had retained, in conjunction with the Distribution Companies. This proposal, which was supported by the Attorney General, was recognized by the DPU in its regulations adopted in June 2009. The regulations provided that "Distribution companies shall consider participating in a DOER-administered solicitation process prior to conducting their own solicitations."[13]

C. The Section 83 Solicitations

As the DPU's regulations were in the process of being finalized, DOER met with the four Distribution Companies, NSTAR, National Grid, Western Massachusetts Electric Company ("WMECO") and Unitil[14] to develop a jointly-issued RFP. The RFP process evolved in three different phases. First, in 2009, DOER and the distribution companies developed a RFP that was limited to Massachusetts-based renewable generation facilities. Second, after the RFP was issued in February 2010, several aspects of the evaluation process, including DOER's role, were modified due to potential antitrust concerns initially raised by one of the Distribution Companies. Finally, due to an amendment in the Department's regulations in response to a lawsuit raised by a potential out-of-state bidder, the RFP was amended to remove the limitation that projects need to be located in Massachusetts or the adjacent offshore federal

[12] As part of the regulatory process, the Department was also directed to "consider the attorney general's recommendations, which shall be submitted to the department of public utilities within 45 days following the filing of such contracts with the department of public utilities."

[13] 220 CMR §17.04(1). Order Adopting Regulations, D.P.U. 08-88-A, 220 CMR 17.00 *et seq.* Distribution company participation was voluntary. However, if a distribution company were to decide to initiate its own solicitation process, it would be required to consult with DOER prior to any submission to the DPU for approval, include in the filing DOER's comments on their solicitation and contracting methods, and specify how they responded to DOER's questions or concerns. 220 CMR §17.04(5).

[14] Fitchburg Gas and Electric Company d/b/a Unitil.

domain. A second solicitation was held with bids due in September 2010, which resulted in three of the distribution companies signing contracts and submitting them to the DPU for approval. Separately, National Grid entered into a preliminary agreement with Cape Wind to negotiate a PPA, obtained approval from the DPU to negotiate with Cape Wind, and obtained the Department's approval of the resulting PPA executed with Cape Wind.

This section of the report addresses (a) these three phases of the development of the RFP process, (b) (i) the resulting bid evaluation, selection, and contract execution process conducted by the Distribution Companies and (ii) the DPU regulatory process regarding the PPAs executed as a result of the RFP process, and (c) the solicitation process involving National Grid and Cape Wind and the resulting PPA, regulatory process, and subsequent appeals. In addition, the current status of the contracted projects is summarized. Finally, Section 83A is compared to Section 83 in the context of suggestions for future improvements of the long-term contract solicitation process.

1. Development of the Original RFP

In early 2009, DOER retained consultants to assist in the development of a solicitation process.15 DOER, with the assistance of its consultants, drafted a RFP document, a bidder response package, and a term sheet (key commercial terms for a model power purchase agreement), which were circulated to the four distribution companies—NSTAR, National Grid, WMECO and Unitil. In June 2009, the first meeting was held among the distribution companies and DOER. For subsequent meetings, DOER and its consultants circulated issues lists based on comments submitted by the distribution companies on the draft RFP documents. The meetings on the structure of the RFP were productive and resulted in various modifications and refinements to the draft solicitation documents.

A series of issues were resolved pertaining to the role of the various distribution companies and DOER in the process. In addition to DOER's role in the development of the RFP itself, DOER would serve in a consultative role to the distribution companies with respect to bid evaluation up to and including development of a short list. The RFP provided for the distribution companies to compare their bid evaluations (with DOER having the ability to review the bids) and the distribution companies would arrive at bid short list selections that would not be incompatible with each other, with DOER playing a coordinative and consultative role. DOER

[15] The consultants were Barry Sheingold, President of New Energy Opportunities, and Wayne Oliver, President of Merrimack Energy Group, Inc., NEO's subcontractor. The work was performed pursuant to a contract between the Massachusetts Clean Energy Center and NEO. NEO has also participated in the preparation of this study as a subcontractor to Peregrine Energy Group.

would also play a consultative role in bid selection and PPA negotiations. Finally, when executed contracts would be submitted to the DPU for approval, DOER would submit its assessment of the process employed by the distribution company and the merits of the particular PPA proposed for approval.

Other issues addressed pertained to evaluation criteria, evaluation process and weighting of price and non-price factors. A three-stage process, proposed by DOER, involved a first-stage of eligibility and threshold requirements, a second stage price and non-price evaluation resulting in a quantitative score and ranking, and a third stage in which reasoned discretion could be exercised based on consideration of specified criteria. The eligibility and threshold requirements included statutory requirements—such as the proposed facility being a RPS-qualifying unit built in Massachusetts (or the adjacent offshore federal domain) after January 1, 2008, which contributes to electricity reliability with Massachusetts, contributes to moderating system peak load requirements, and contributes to Massachusetts employment—as well as other requirements typical for RFP processes of this kind, such as the demonstration of site control.

The second stage evaluation (for those proposals that meet the requirements of the first stage evaluation) involved a price and non-price evaluation, where price factors were weighted 80 percent and non-price factors weighted 20 percent.16 The 80/20 split was a compromise agreeable to the participants.

DOER proposed, and the distribution companies agreed to, a third stage of the evaluation process where the distribution companies, in consultation with DOER, would determine those proposals that had the highest value based on consideration of the following factors:

- Ranking in the second stage evaluation;
- Cost effectiveness of the bids (pricing);
- Risk associated with project viability;
- The extent to which additional employment in Massachusetts would be created; and
- Portfolio effect: the value of diversity of resources—by size and type of resources.

These factors were to be considered in selecting a short list.

[16] Non-price evaluation factors included consideration of status of siting and permitting, project development status and operational viability, experience and capability of the project development team, financing capability, and exceptions to the Model PPA.

In August 2009, the Distribution Companies, in coordination with DOER, circulated a draft RFP and term sheet for comment to interested renewable energy developers and other parties. Comments were received from a variety of developers and a renewable energy advocacy association. After considering the comments, the distribution companies and DOER filed the proposed RFP and response package with the DPU. A term sheet or model PPA was not included in the filing, but the joint petitioners stated that a model PPA would be issued with the RFP following DPU approval. In addition, the filing included a high level summary of (a) the comments submitted on the draft RFP and (b) the extent to which they were incorporated in the proposed RFP submitted to the Department.

A number of parties requested that the Department grant approval of the proposed RFP, but on specified conditions, including requiring that a Model PPA be filed for DPU prior approval, that the allocation of points between price and non-price factors be reduced from 80/20 to a ratio implying heavier weighting of non-price considerations, that the third stage of the evaluation process be eliminated on the ground that it entailed the exercise of too much discretion on the part of the distribution companies, and that the time period to conduct the solicitation be enlarged or shortened. The Department, however, approved the proposed timetable and methods of solicitation contained in the RFP as being consistent with Section 83 and the Department's regulations.17 The DPU generally did not want to limit the flexibility of the process and generally deferred to the soliciting participants. With regard to certain issues, the Department recognized DOER's "judgment and experience" and "DOER's full support of the proposal" as "evidenced by its joint sponsorship of the petition."18 On the same day, the DPU also approved National Grid's proposal to negotiate a PPA with Cape Wind.19 National Grid, however, remained as a participant in the statewide RFP process.

While the Distribution Companies and DOER addressed and resolved many issues in drafting the RFP, it was difficult to agree on a number of provisions of the Model PPA. DOER attempted to address a number of concerns raised by developers and a renewable energy advocacy association that pertained primarily to the perceived financeability of the Model PPA.

Following the DPU's order authorizing the Distribution Companies, in consultation with DOER, to issue the proposed RFP, the terms of the Model PPA were agreed upon. On January 15,

[17] Order, D.P.U. 09-77 (December 29, 2009).

[18] *Id.* At 21- 22.

[19] Order, D.P.U. 09-138 (December 29, 2009).

2010, the RFP, bidder response package and Model PPA were posted on a website dedicated to the RFP process.

At the same time, the details of the price and non-price evaluation methodology were being developed, consistent with the criteria set forth in the RFP. The Distribution Companies, in consultation with DOER, retained Levitan Associates, an economic consulting firm, to develop a common market price forecast to be utilized in the economic evaluation of bids.

2. Revision in the Roles of DOER and the Distribution Companies in the Bid Evaluation and Selection Process

Shortly after bid submittal, one of the distribution companies, based on a legal assessment it had conducted, expressed to DOER and the other distribution companies that the collaborative approach among the distribution companies in the bid evaluation process, and DOER's participation in that process, as envisaged in the RFP, raised antitrust concerns. As a result, the Distribution Companies decided not to coordinate among themselves in the bid evaluation and short list selection part of the RFP process. In addition, DOER agreed to withdraw from its consultative role with respect to the bid evaluation/bid selection/contract negotiation process. DOER sent a letter dated April 14, 2010 to the DPU with a copy to bidders informing them of this change in the process.

As a result, the RFP process was modified to one where there were to be multiple independent bid evaluation/bid selection/contract negotiation processes that were conducted by each distribution company, with no consultative role played by DOER. Since Section 83 and the DPU's regulations only required DOER to play a consultative role with regard to the design of the solicitation process, and not its implementation, this did not violate Section 83 or the DPU's implementing regulations. However, it effectively eliminated DOER's ability to monitor the process after the submission of bids and to address any problems that might arise other than on an after-the-fact basis.

3. Removal of the Geographic Limitation on Eligible Facilities

On April 16, 2010, TransCanada Power Marketing Ltd. ("TransCanada") brought a lawsuit in federal court, alleging that Section 83, the DPU's implementing regulations, and the RFP issued on January 15, 2010 discriminated against out-of-state generators in violation of the Commerce Clause of the United States Constitution.[20] On June 9, 2010, the DPU issued emergency

[20] TransCanada Power Marketing Ltd. V. Bowles, Civil Action No. 4:10-cv-40070-FDS (D. Mass. April 16, 2010).

regulations, ultimately finalized, which removed the geographic limitation that an eligible renewable energy facility needed to be located "within the jurisdictional boundaries of the [C]ommonwealth, including state waters or adjacent federal waters" and removed the requirement that where feasible, additional employment be created "in the [C]ommonwealth."21 The DPU directed the Distribution Companies, in consultation with DOER, to reopen the RFP for a reasonable time to allow out-of-state generators to submit proposals.22 In doing so, the DPU stated that "the distribution companies should be mindful of the express language of the statute, which calls upon distribution companies to 'enter into cost-effective long-term contracts to *facilitate the financing* of renewable energy generation.' St. 2008, c. 169 § 83 (emphasis added)."23

At the time the DPU issued the emergency regulations, NSTAR had already executed three PPAs and WMECO and Unitil were at an advanced stage of bid evaluation and selection.24 NSTAR submitted the three PPAs to the DPU for approval, but in light of the emergency regulations, they were denied without prejudice.25

On July 14, 2010, the Distribution Companies, in consultation with DOER, submitted an amended RFP to the DPU for approval ("Amended RFP"). Under the proposed Amended RFP:

- The geographic limitation on eligible facilities was eliminated;
- The requirement that additional employment be created "in the Commonwealth" was eliminated;
- Consistent with the April 14, 2010 letter filed by DOER with the Department, the RFP was modified to remove (a) any collaborative process between the Distribution Companies and (b) DOER's consultative role during the bid evaluation, bid selection, and contract negotiation process;
- In order to enhance the consideration of "facilitating financing" in the RFP process:

[21] Order Adopting Emergency Regulations, D.P.U. 10-58 (June 9, 2010); Order Adopting Final Regulations, D.P.U. 10-58-A (August 20, 2010).

[22] Order Adopting Emergency Regulations at 6.

[23] *Id*.

[24] National Grid had already signed a PPA with Cape Wind through a negotiated process approved by the DPU.

[25] Order of Dismissal Without Prejudice, D.P.U. 10-71, 10-72, and 10-73 (August 13, 2010).

- Bidders were asked the extent to which obtaining a PPA in the RFP process would facilitate the financing of their project;
- Facilitating financing was added as a consideration in both the non-price evaluation and in the third stage of the evaluation process.

In preparation for the economic evaluation of bids from facilities located outside of Massachusetts, the Distribution Companies procured from Levitan Associates a forecast of energy LMPs for locations in ISO-New England but outside Massachusetts (in addition to the forecast for Massachusetts locations previously provided).

On August 27, 2010, the DPU approved the timetable and methods of solicitation embodied in the Amended RFP.26 On September 2, 2010, the Amended RFP was issued and posted on the website developed by the Distribution Companies and DOER for the solicitation.27

Bids were submitted in early October 2010. NSTAR received proposals for 74 renewable energy projects totaling 2,513 MW and representing 7.5 million MWh/year.28 WMECO and Unitil also received a large number of proposals.29 Many developers submitted proposals for sales from the same projects to multiple utility buyers.

Several months later, NSTAR entered into three PPAs with wind energy projects with a total installed capacity of approximately 109 MW (one of which was located in Massachusetts), WMECO entered into one PPA with a 37.5 MW wind energy project, and Unitil entered into one PPA with a 2.2 MW expansion of a hydroelectric project.

4. The DPU Proceedings for Approval of the PPAs

On January 31, 2011, WMECO filed its petition for approval of the PPA it had executed pursuant to the Amended RFP, followed by NSTAR's submission in February of its petitions for approval of the three PPAs it had executed, and Unitil's application for approval of its PPA in mid-March.

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[26] Order, D.P.U. 10-76 (August 27, 2010).

[27] www.massachusettsrenewableenergyrfp.com.

[28] NSTAR Electric Company, D.P.U. 11-05, 11-06, 11-07 (August 19, 2011) at 42. D.P.U. 11-05, 11-06, and 11-07 (May 27, 2011) at 8.

[29] WMECO received conforming bid proposals for 87 different renewable energy projects. Testimony of Judy Chang and Jurgen Weiss, Witnesses for the Attorney General ("Chang/Weiss Testimony"), D.P.U. 11-12 (June 21, 2011) at 8. Unitil received a total of 105 bids from 49 bidders representing 84 individual projects. [29] Chang/Weiss Testimony, D.P.U. 11-30 (July 15, 2011) at 8.

Expert witnesses for the Attorney General testified that the three distribution companies acted in conformance with the guidelines set forth in the Amended RFP in terms of their evaluation of the bids and bid selection. DOER supported approval of all of the PPAs. No party in any of the proceedings opposed the petitions.30 The Department approved all of the PPAs. Generally speaking, the path to regulatory approval was straightforward and noncontroversial. The NSTAR proceedings were expedited at the request of one of the developers. All in all, the proceedings took between six to nine months from filing of petitions to DPU decisions.

NSTAR

After having concluded the second evaluation stage, NSTAR "targeted" the nine top-ranked bids for further evaluation. NSTAR sought improved pricing from these bidders. NSTAR then short listed four proposals. The other five involved existing or other facilities for which NSTAR determined that contracts in this solicitation would not facilitate financing, based on the representations of the bidders. One shortlisted bidder dropped out. NSTAR signed contracts with the remaining three bids, which were wind projects. Expected energy output from the three wind projects represented 1.6 percent of NSTAR's distribution load. Two projects—the 28.5 MW Hoosac project located in Massachusetts and the 48 MW Groton project located in Maine—were being developed by subsidiaries of Iberdrola. The other project—the 32.4 MW Blue Sky project located in Maine—was being developed by a subsidiary of First Wind. Both Iberdrola and First Wind are experienced wind energy developers with successful track records.

While the pricing of the PPAs were treated as confidential information, as had the PPAs NSTAR had previously executed with in-state projects pursuant to the Initial RFP issued in January 2010 ("Initial RFP"), NSTAR indicated that the weighted average price of the PPAs executed pursuant to the Amended RFP was approximately 40 percent lower than the weighted average price of the PPAs under the Initial RFP.[31]

The Attorney General's witnesses—the Brattle Group's Judy Chang and Jurgen Weiss—conducted a rigorous assessment of NSTAR's bid evaluation. They concluded that NSTAR reasonably exercised discretion consistent with the framework set forth in the Amended RFP and confirmed NSTAR's scoring of the bids. DOER agreed with that overall conclusion. In briefs, no party opposed Department approval of the PPAs.

[30] While there was no opposition to the PPAs themselves, there were some issues raised with respect to the cost recovery mechanisms.

[31] Testimony of James J. Daly, Exhibit JGD-1, p. 23, D.P.U. 11-05.

WMECO

After conducting its price and non-price second stage evaluation in accordance with the bid evaluation protocol developed by the Distribution Companies and DOER, WMECO selected the top seven highest scoring projects for its short list, but focused on the three highest ranking projects.32 WMECO selected the Noble Passadumkeag proposal as its preferred project—a proposed sale of energy, RECs and capacity (capacity would be transacted through a financial swap) from a planned 37.5 MW wind project located in Maine with an estimated annual output of 115,085 MWh.33 The estimated annual output represented slightly more than three percent of WMECO's annual distribution load, which was the upper end of WMECO's procurement target, as reflected in the Amended RFP.34

In its initial bid, the Noble proposal ranked second, although it was the most attractively priced project. The top-ranked project, when considered alone, was too small to meet WMECO's procurement target. WMECO decided that Noble's proposal was "the best match" "based on several factors, including the cost effectiveness of the bid, the size of the project, and the extent to which a Power Purchase Agreement would facilitate the financing of renewable energy generation."35

WMECO sought and obtained a price reduction from Noble.36 After obtaining the refreshed bid from Noble, the Noble proposal was both the top-ranked project as well as the most attractively-priced proposal.37

The Attorney General's witnesses testified that WMECO's process for bid evaluation and selection was a reasonable exercise of discretion pursuant to the framework set forth in the Amended RFP.

[32] Testimony of Timothy J. Honan at p. 16, WMECO's Response to IR AG-3-008(a).

[33] Testimony of Timothy J. Honan at p. 16.

[34] See Amended RFP Section 1.1, n. 1 (WMECO Response to IR AG-1-008 at p. 5, n.1). The nominal target was 1.5 percent of annual distribution load. Amended RFP Section 1.1.

[35] WMECO Respose to IR-AG-3-008(a). In fact, the top-ranked project was an existing project and the bidder's proposal stated that a long-term contract was not needed to facilitate financing.

[36] WMECO Response to IR-AG-3-008(c).

[37] Testimony of Timothy J. Honan at p. 16.

Unitil

Pursuant to the RFP process, Unitil signed a 15-year contract with Black Bear Hydro Partners, LLC ("Black Bear" or "BBHP"), an indirect subsidiary of ArcLight Energy Partners Fund II, L.P. ("ArcLight") for RECs from its planned 2.2 MW expansion of the Stillwater B hydroelectric project in Old Town, Maine. The projected annual output from the project is 18,299 MWh, which represented 3.8% of the Unitil's distribution load, which is somewhat larger than the 3.0% percent minimum purchase requirement under Section 83 of the GCA.

After the second stage of the evaluation process, Unitil selected the top ten ranked bids for further evaluation. In the third stage evaluation, applying the criteria set forth in the Amended RFP, Unitil selected three bidders for its short list. The Stillwater B project was one of the top-ranked projects, was a planned generating facility expansion while several others were simply existing facilities. Moreover, the size of the Stillwater B contract was in line with Unitil's procurement target, while many others were considerably larger. Unitil sought a price reduction from several bidders, but only received a price reduction from Black Bear for the Stillwater B project. Unitil decided to negotiate a contract with Black Bear.

The Attorney General's expert witnesses submitted testimony in which they concluded that Unitil's evaluation process, short listing and selection of Black Bear was a reasonable exercise of discretion pursuant to the Amended RFP. DOER's review disclosed that Unitil used its own methodology for the price evaluation, rather than the methodology developed by the Distribution Companies and DOER, but it did not make a difference in the result. Unitil and DOER sought approval of the PPA, and the Attorney General did not oppose it.38

5. *The Department's Decisions on the NSTAR, WMECO and Unitil PPAs*

In a decision issued on August 19, 2011, the Department found that that NSTAR's proposed contracts satisfied the applicable requirements of Section 83 of the GCA, including cost-effectiveness, contribution to employment, commercial operation date, RPS qualification, enhanced reliability, moderation of system peak loads, and that the long-term contracts would facilitate financing of the proposed projects.39 The Department also found that the proposed

[38] DOER proposed that Unitil be directed to utilize the cost recovery mechanism approved in the NSTAR case for RECs to be purchased under the Stillwater B PPA, rather than charging basic service customers the difference between the contract rate and the market rate, as Unitil had proposed.

[39] NSTAR Electric Company, D.P.U. 11-05, 11-06, 11-07 (2011) at 16-38.

contracts were in the public interest, finding that "the Company selected the projects using a solicitation process that was open, fair, and transparent and, therefore competitive."40

While the Attorney General's witnesses supported the reasonableness of the Distribution Companies' evaluation and bid selection processes in the context of the Amended RFP, they also expressed some concerns and suggested possible future improvements. The Department found that the current proceedings were not the appropriate forum to consider the recommendations, but encouraged DOER and the distribution companies to consult with the Attorney General with respect to the development of future RFPs.41 Following a similar analytic approach as in the NSTAR decision, the Department approved WMECO's entry into a long-term contract with Noble Passadumkeag in an order issued on October 7, 2011,42 and Unitil's contract with Black Bear in an order issued on December 7, 2011.43

D. Cape Wind

On December 3, 2009, National Grid sought approval from the DPU to negotiate a long-term PPA with Cape Wind. Later that month, the Department approved National Grid's proposed

[40] NSTAR Electric Company, (August 19, 2011) at 48. The Department also approved NSTAR's revised proposal on cost recovery under which NSTAR would resell energy into the market and retain RECs for basic service, charging its basic service customers the spot price for RECs. Distribution customers would pay, or receive a credit for, the difference between the contract price and the market price for energy and RECs.

[41] *Id* at 52-53. The issues raised by the Attorney General and recommended changes are addressed along with some other issues pertaining to the Section 83 procurements and suggestions for improvements in Section IV.E of this report.

[42] Western Massachusetts Electric Company, D.P.U. 11-12 (October 7, 2011). The Department also approved WMECO's proposed cost recovery mechanism under which energy and RECs would be sold into the market, with distribution customers paying (or receiving a credit for) the net difference, with the financial settlement on the capacity price under the PPA being treated in a similar fashion. *Id.* at 47-49.

[43] Fitchburg Gas and Electric Company, d/b//a Unitil, D.P.U. 11-30, at 35-36 (December 11, 2011). While Unitil had proposed to use the purchased RECs for its basic service services and to charge them the Black Bear PPA contract price, the Department ordered that the mechanism adopted in the NSTAR case be applied—that is, basic service would be charged the market price for RECs and the distribution customers, who would be paying the 4% remuneration to Unitil, would obtain the benefit and detriment of the REC contract price relative to REC market prices. *Id.* at 41-44.

timetable and method of solicitation and potential execution of a long-term contract with Cape Wind as consistent with the requirements of Section 83.[44]

Following several months of negotiations, National Grid and Cape Wind negotiated a PPA and submitted it to the DPU for approval. During the course of the lengthy proceedings, the PPA was amended pursuant to a settlement agreement with National Grid, the Attorney General, Cape Wind, and DOER. In November 2010, the Department approved the amended PPA.[45]

Cape Wind is a wind energy facility of up to 468 MW to be located offshore of Massachusetts in the federal waters of Nantucket Sound. National Grid agreed to purchase 50 percent of the energy, capacity, and RECs associated with the project for $187 per MWh (2013 base year) for 15 years, escalating at 3.5 percent per year. There are provisions for upward price adjustments under some circumstances and for downward price adjustments in other circumstances, as well as purchase quantity adjustments if Cape Wind revises the nameplate capacity of the facility. National Grid also has an option to extend the PPA for an additional 10 years.

The Department found that the PPA would assist Cape Wind in securing financing, satisfying a requirement that the PPA "facilitate the financing" of the project.

The Department recognized that the power products to be purchased under the PPA are expensive, and that there are other opportunities to purchase renewable energy at lower cost.[46] However, the Department found that "the Cape Wind facility offers significant benefits that are not currently available from any other renewable resources" and that "these benefits outweigh the costs of the project."[47]

The Department compared the expected costs of the PPA to the market value of the products purchased by National Grid and the value of the electric energy market price suppression benefits to National Grid customers. While this produced net costs, the Department found that the PPA was cost-effective because they were outweighed by un-quantified benefits. These benefits included the positive impact of certain contract provisions that could reduce costs to

[44] Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, D.P.U. 09-138 (December 29, 2009).

[45] Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, D.P.U. 10-54 (November 22, 2010).

[46] *Id.* Executive Summary, p. xvii.

[47] *Id.*

ratepayers, the role that such a large project could play in achieving compliance with Massachusetts RPS requirements, the avoidance of very substantial compliance costs under the Massachusetts Global Warming Solutions Act, G.L. c. 21N, employment benefits, and having especially favorable characteristics due to its location and production profile resulting in enhanced electric system reliability and moderation of system peak load.[48] Finally, the Department found that the PPA was in the public interest due to the unique benefits of Cape Wind, including its size, location on the regional transmission system and the absence of transmission constraints, making it attractive relative to other renewable energy projects, the reasonableness of pricing for an offshore wind project, and the reasonableness of the contract size for National Grid.[49]

With regard to cost recovery, the DPU approved National Grid's proposal to use the energy, capacity and RECs purchased from Cape Wind for their basic service customers, but to charge the basic service customers a market price for these products. Distribution customers would be charged (or obtain a credit for) the difference between the contract price and market price for energy, RECs and capacity and would be charged 4 percent of the PPA payments as remuneration for National Grid.

Four parties, the Alliance to Protect Nantucket Sound ("APNS"), AIM, NEPGA, and TransCanada, filed an appeal. The Massachusetts Supreme Judicial Court upheld the Department's order approving the Cape Wind PPA.[50] Against a challenge that the PPA was the result of an unconstitutional exclusion of out-of-state projects, the Court upheld the Department's finding that National Grid's decision to enter into the Cape Wind PPA was without regard to the geographic limitations in Section 83, which the Department had subsequently removed for Section 83 solicitations following the *TransCanada* lawsuit. The Court also upheld the DPU's interpretation of, and findings regarding, the "cost-effectiveness" of the Cape Wind PPA, the satisfaction of the "public interest" standard, and the Department's authority under Section 83 to authorize an individual negotiation. Finally, the Court upheld the Department's authority to treat "facilitation of financing," referenced as a purpose of Section 83, as a requirement.[51]

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[48] *Id.* at 208-215.

[49] *Id.* at 283-84.

[50] Alliance to Protect Nantucket Sound v. Department of Public Utilities, 461 Mass. 166 (December 28, 2011).

[51] In a companion case, the Supreme Judicial Court also denied APNS's appeal regarding its request to the DPU to reopen the record to introduce new evidence. Alliance to Protect Nantucket Sound v. Department of Public Utilities, 461 Mass. 190 (December 28, 2011).

E. Current Status of Projects

Each of the three wind projects for which NSTAR signed PPAs are in commercial operation or in an advanced state of construction. In early December 2012, Governor Patrick and other state officials celebrated the 28.5 MW Hoosac wind farm in Florida and Monroe, Massachusetts as the construction project neared completion.[52] Iberdrola's other project, the 48.0 MW Groton wind farm in Groton, New Hampshire, is also in an advanced state of construction with an expected completion date by the end of December 2012.[53] First Wind's 34.0 MW Bull Hill wind project in Hancock County, Maine achieved commercial operation on October 31, 2012.[54]

BBHP's 2.2 MW Stillwater B hydroelectric expansion project, which is under a 15-year REC-only contract with Unitil, recently obtained a necessary license amendment from the Federal Energy Regulatory Commission[55] and is now in construction.

In November 2012, the Maine Department of Environment Protection denied Passadumkeag Wind Park LLC's application for a permit, citing adverse visual impacts on a nearby scenic lake.[56] While the project developer, which has a PPA with WMECO for the 37.5 MW project, has the right to appeal the decision, the future prognosis is uncertain, at best.

All in all, the success rate from the Amended RFP so far is 80% of the projects and 74% of the generating capacity.

Last month, NSTAR received approval from the DPU for the PPA it had executed with Cape Wind earlier this year.[57] The PPA, which is for 27.5 percent of the project's energy, capacity and RECs, is very similar to the PPA Cape Wind signed with National Grid. Cape Wind's financial

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[52] http://www.mass.gov/governor/pressoffice/pressreleases/2012/20121203-hoosac-wind-power-project-celebrated.html.

[53] http://www.concordmonitor.com/article/356769/windmills-rise-along-with-hopes.

[54] http://www.firstwind.com/projects/bull-hill.

[55] Black Bear Hydro Partners, LLC, Order Amending License and Revising Annual Charges, 140 FERC ¶62,195 (September 14, 2012).

[56] http://bangordailynews.com/2012/11/09/news/penobscot/maine-dep-rejects-passadumkeag-wind-project/.

[57] NSTAR Electric Company, D.P.U. 12-30 (November 26, 2012).

advisor has stated that the two long-term contracts provide a "critical mass" as Cape Wind continues efforts to secure financing.[58]

F. Section 83A and Its Significance for the Review of the Section 83 Solicitation Process

Section 83A is similar to Section 83, but with a number of modifications. We summarize them in the table below because future solicitations under Section 83A will be different from the solicitations conducted under Section 83. This is relevant to our assessment, and stakeholder views, regarding the Section 83 solicitations and ways to improve future solicitations.

Matter Addressed	Section 83	Section 83A
Time frame	Sunsets on December 31, 2012 (Section 36 of Chapter 209)	January 1, 2013- December 31, 2016
Allowable Solicitations	Competitive bidding or individual negotiations	Competitive bidding only
Number of solicitations/% of load	2 solicitations for 3% of load	2 solicitations for 4% of load (3.6% after set-aside for small non-solar renewable distributed generation, which will have separate RFPs)
Term of PPAs	10 to 15 years	10 to 20 years
Solicitation approach	-DPU rules: Distribution Companies to consider "DOER-administered solicitations" -Amended RFP: Distribution Companies evaluate bids, short list bids, and negotiate bids separately without consulting each other or DOER	-Solicitations to be conducted jointly by Distribution Companies and coordinated by DOER, unless the DPU rules that an individual company solicitation would be more cost effective to ratepayers -Distribution Companies shall enter into a contract with the

[58] http://www.boston.com/news/local/massachusetts/2012/11/26/state-approves-cape-wind-deal-with-nstar/6sygW0D6QrJVs15xTxl9EO/story.html.

		winning bidders for their share of the products purchased (based on relative sizes of their distribution loads)
Distribution Company consultation requirement	DOER	DOER and the Attorney General
Remuneration to Distribution Companies	4% of annual payments	2.75% of annual payments
Project commercial operation date	On or after January 1, 2008	On or after January 1, 2013
Statutory criteria (differences only)[59]	Following TransCanada lawsuit: "Where feasible, create additional employment"	"Where feasible, create additional employment and economic development in the commonwealth"

Thus, the one-on-one negotiation process that National Grid pursued with Cape Wind would not be permissible under Section 83A, which mandates a competitive bidding process. As another example, individual Distribution Company bid evaluation, bid selection and contract negotiations without any coordination with other Distribution Companies or DOER, is much less likely to occur under Section 83A.

In the next section, we provide our assessment of the relationship between long-term contracts under Section 83 and financing renewable energy projects.

[59] In addition, Section 83A has a provision with no counterpart in Section 83. If there are significant transmission costs included in a bid, Section 83A directs the DPU to "authorize the contracting parties to seek recovery of such transmission costs of the project through federal transmission rates, consistent with policies and tariffs of the federal energy regulatory commission, to the extent the department finds such recovery is in the public interest."

III. Assessment: Has the Long-Term Contracting Mandate Reasonably Supported the Commonwealth's Renewable Energy Goals?

A. Introduction

In order to assess the extent to which the long-term contracting requirements of Section 83 reasonably support the renewable energy goals of the Commonwealth, we address the need for long-term contracts to support Massachusetts' RPS goals and the manner in which long-term contracts aid in the financing of construction of renewable energy projects. This section then addresses the resulting benefits.

B. The Role of Long-Term Contracts Under Section 83 in Facilitating Financing of New Renewable Generation

1. *Without Contracts, Renewable Energy Revenue Sources are Subject to Considerable Volatility*

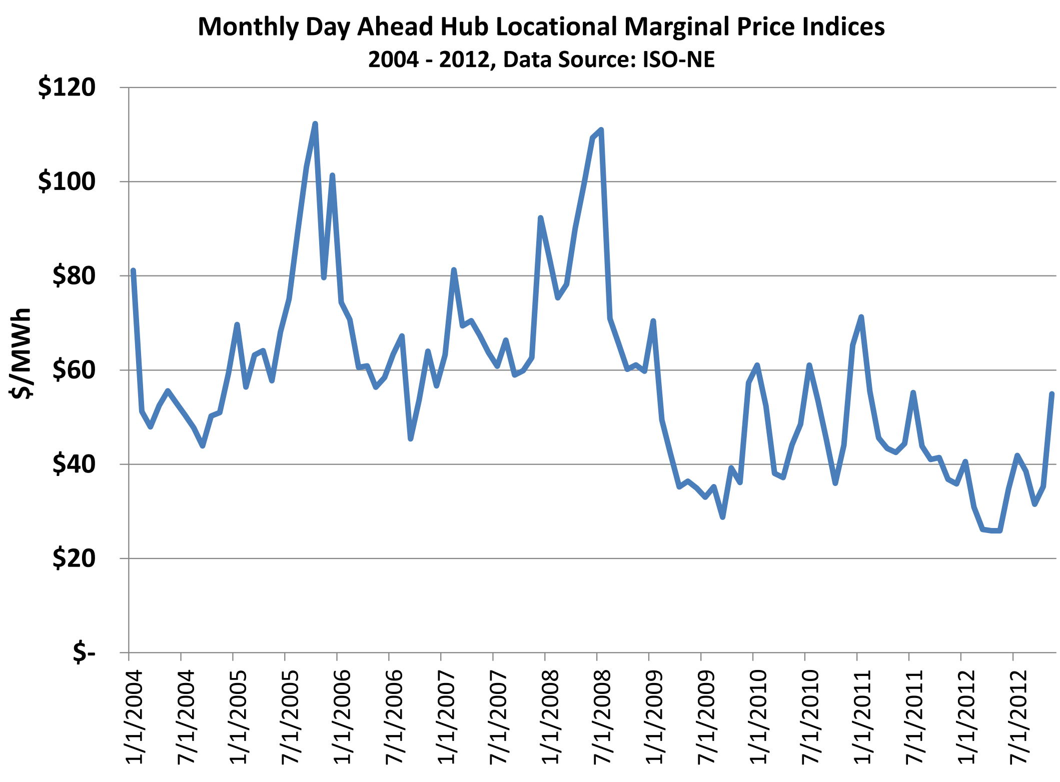
Long-term contracts provide renewable energy developers with an opportunity to obtain a predictable amount of revenue assuming that their plants will perform as projected. An understanding of the components and characteristics of the types of revenue on which renewable energy developers and their investors rely is important in understanding the role of long-term power contracts in financing construction of renewable energy projects.

Class I renewable generation projects provide two types of marketable products—energy and RECs—and many provide capacity.[60] Of the six PPAs executed by the Distribution Companies and approved by the DPU in 2010-2011, three PPAs involved the purchase of energy, RECs, and capacity (three wind projects), two PPAs were for energy and RECs (two wind projects), and one PPA was only for RECs (an expansion of an existing hydro project). As an intermittent resource, wind energy projects can provide only a limited amount of capacity to ISO-New England. Hence, the bulk of the market revenues on which wind energy developers rely to pay for their revenue requirements are from the sale of electric energy and RECs. Revenue requirements

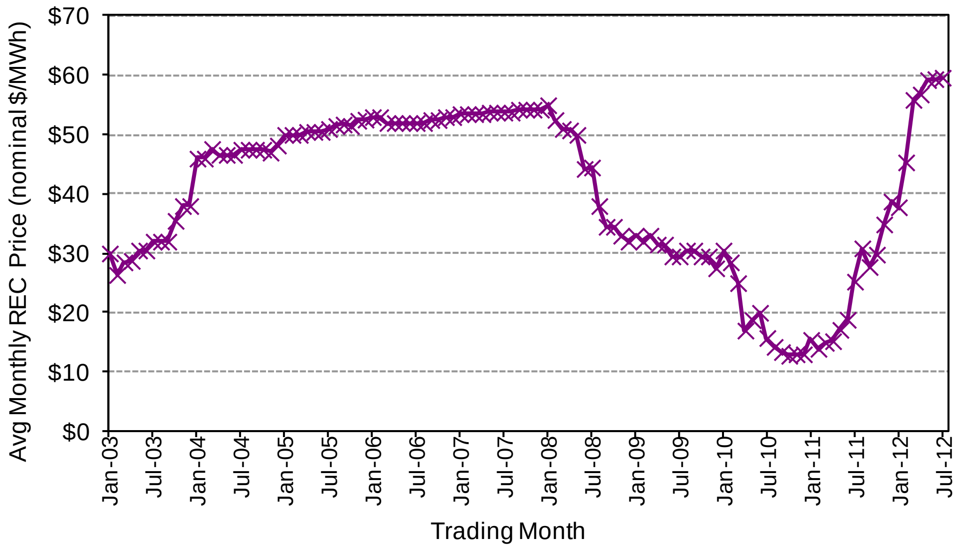
[60] Energy is the amount in megawatthours (MWh) that a generating plant produces. Capacity is a measure of capability to produce MWhs and is measured in megawatts (MW) or in kilowatts (kW, which is .001 MW).

are the funds needed to pay for construction of the power plant and associated development costs, the operation and maintenance of the project, and a return on the capital investment in the project sufficient to attract the required investment from investors.

Over time, there has been considerable volatility in the market for energy and RECs. Electric energy prices in New England have moved up and down with market prices for natural gas in light of the large role that natural gas-fired generators play in the New England electricity markets. Unlike the case of natural gas generators, there is no correlation between the cost of production for renewable energy generators and the market value of energy. Hence, renewable energy developers generally have a need to hedge their market price risk involving electric energy. Below is a graph showing average monthly locational marginal energy prices in ISO-New England.



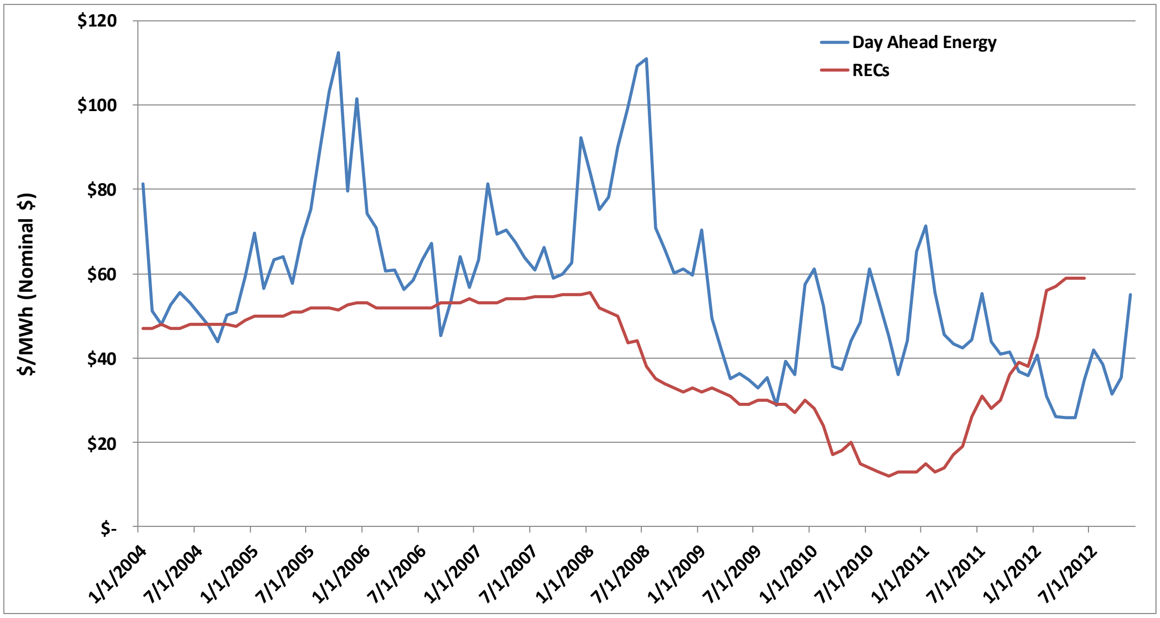
The market for Massachusetts Class I RECs is much smaller than the market for electric energy and has experienced equal or more volatility. Class 1 (formerly new) REC prices have increased from approximately $27 in 2003 to approximately $50 in 2004-2008 near the ACP when supply was very tight relative to demand down to approximately $30 in 2009 to near $15 from July 2010 to June 2011 back up to approximately $40 in early 2012 to $60+ in recent months (near the inflation-adjusted ACP). These fluctuations in REC market prices are shown in the graph below. [61]



Sources: Evolution Markets (through 2007) and Spectron (2008 onward). Plotted values are the last trade (if available) or the mid-point of Bid and Offer prices, for the current or nearest future compliance year traded in each month.

The market prices for energy and RECs are not well correlated to each other, including periods when both energy and REC prices are high, periods when they are both low, and periods when they are inversely related, as the following graph shows. The combination of these two products does not substantially reduce the volatility or market price risk.

[61] The graph was provided by Lawrence Berkeley National Laboratory.



REC market prices are driven by two key factors—(1) fundamental value if the market is in balance, and (2) value driven by supply and demand, especially if there are shortages or surpluses. The fundamental value of a REC is often viewed as the difference between the marginal renewable generation unit's revenue requirements (as may be adjusted to take into consideration federal tax benefits) minus the expected market value of the energy produced and any marketable capacity provided on a $/MWh basis.[62] For Class I resources, the marginal renewable generating unit is an onshore wind energy project since this is the least costly form of Class I renewable generation that can be produced in quantity.

While one would expect that based on the long-term fundamental value approach, REC prices would be inversely related to energy prices (i.e., when energy prices rise, REC prices would decline and vice-versa), in practice, REC prices move up and down (sometimes, quite sharply) based on short-term supply and demand. Some of the reasons for this variability are:

- the RPS markets are much smaller in terms of MWh (and total dollar value) than the energy markets;
- demand is set primarily by RPS statutes and regulations in the region; and

[62] The marginal renewable generating unit is a hypothetical RPS-qualified generating unit with costs of production where the supply curve and demand curve meet. (This is not the same as the marginal generator in the ISO-NE energy market.) The demand curve is based on the expected RPS requirements in the particular region under study.

- developing, financing and building new renewable generation usually takes years to accomplish with the need to overcome considerable hurdles.

Hence, there is a tendency for shortages to develop with REC prices reaching the upper limit of allowable REC prices, as is currently the case. On the other hand, surpluses may develop, driving REC prices sharply downward, as was the case in late 2010 and early 2011, and could possibly drive REC prices into the single-digit range.

Moreover, RECs, unlike electric energy, are not a natural commodity—they are the product of state legislatures and administrative agencies. There is the concern--especially if REC prices are in the upper range of allowable prices for a sustained basis--that the RPS law or regulations might be modified to reduce RPS demand or increase RPS eligibility, thus reducing REC prices, or the RPS itself might be eliminated. Also, a particular kind of renewable resource might lose favor and either be "delisted" or be subject to new compliance requirements. Hence, with RECs there is a relatively high perceived "regulatory risk" or risk that a "change in law" could affect revenue through changes in REC market prices and/or RPS qualification for generating units in the future. The perception of the degree of this type of risk may also vary based on the particular type of renewable generation.

Another element to the mix, whether viewed as a revenue source or as an offset to revenue requirements, is federal tax credits or related benefits for renewable energy projects. Since originally enacted by the Energy Policy Act of 1992, there has been a federal production tax credit ("PTC") for wind energy projects and other specified renewable energy projects that go into service before a defined in-service deadline.[63] The PTC is $22/MWh for wind energy in 2012 ($11/MWh for hydro), has an annual inflation-adjustment, and has a term of 10 years following the in-service date. The PTC has been extended every few years over the past two decades. The current in-service deadline for wind projects is December 31, 2012 (December 31, 2013 for hydro).

The current version of the PTC was enacted as part of the American Recovery and Investment Act of 2009. This legislation extended the then-existing in-service deadline and allowed facilities that qualify for the PTC to opt instead to take the federal business energy investment tax credit ("ITC") or an equivalent cash grant from the U.S. Department of Treasury.[64] The ITC

[63] 26 U.S.C. §45.

[64] See 26 U.S.C. § 48(a)(5)(C)(i). Section 1603 of the American Recovery and Reinvestment Act, as amended by Section 707 of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 provides for the U.S. Treasury Department to make payments to wind developers in lieu of the ITC for plants placed in service in 2012 and which meet other applicable requirements.

for PTC-eligible technologies is generally equal to 30% of eligible costs. Both the ITC and the cash grant are subject to similar in-service deadlines as the PTC.[65]

While Congress has extended the PTC many times before, there is substantial uncertainty in the current political climate as to whether the PTC will be extended, for how long, in what form, and in what amount. The prospect for continuation of the ITC for PTC-eligible projects and the Treasury cash grant in lieu of the ITC is considered less likely. For solar facilities, on the other hand, the in-service deadline for the investment tax credit of 30% of the qualifying investment is in place through December 2016.[66]

These tax benefits (or cash payments in lieu of the ITC) have the effect of lowering the revenue needs of renewable energy developers. Hence, to the extent these tax benefits are discontinued or reduced, revenue requirements will increase, which will likely result in increases in market REC prices (at least in the long run) and prices to be paid to renewable energy developers under long-term contracts. By requiring project developers to rely more on REC revenues, the discontinuance or reduction of federal tax benefits will enhance their need for long-term contracts to manage both the market price risk and political risk associated with RECs.

In conclusion, the outlook for renewable energy developers includes very high levels of volatility with respect to future market values of wholesale electric energy and REC prices and considerable uncertainty with respect to future federal tax benefits and renewable energy policies.

2. *Renewable Energy Developers and Investors Require Long-Term Contracts to Finance New Grid-Scale Projects*

In this context, developers of, and investors in, new renewable generation projects require long-term contracts before they will finance and built new grid-scale power plants. In the past seven or eight years, the only such renewable generation project to be built primarily on a merchant basis (i.e., without long-term contracts) was TransCanada's 132 MW Kibby Project in Maine,[67] and our stakeholder interview results indicate that it is unlikely that such a decision

[65] The structure of the cash grant deadlines, however, varies from those applicable to the PTC and ITC.

[66] 26 U.S.C. § 48

[67] TransCanada did enter into a 10-year agreement with NSTAR in2007 to sell energy and RECs from 30 MW of the Kibby facility or approximately 23% of the energy and RECs produced by Kibby. NSTAR entered into this arrangement as part of the NSTAR Green Program. See NSTAR Electric Company, D.P.U. 07-64-A (2008).

would be replicable in the future. The bulk of renewable energy developers use project financing to raise debt and/or tax equity (equity investment primarily oriented to utilizing the PTC or ITC). Lenders and tax equity providers generally require long-term contracts with creditworthy buyers as a condition to making project investments.

There are also several large renewable energy developers that finance projects with internal funds and/or raise funds on the strength of their own company credit—known as balance sheet financing. However, company managements also generally require that there be revenue certainty for energy and RECs before they will commit to financing construction of the projects.

All 11 of the renewable energy developers interviewed for this study stated that long-term contracts for energy and RECs with creditworthy buyers are critical to their ability to finance and build new renewable energy projects.[68] This included representatives of three renewable energy developers which employ or have employed balance sheet financing. Their companies' policy is to require long-term contracts as a prerequisite for management to commit funding for project construction.

The interviews conducted confirmed that renewable energy developers will not build large multi-MW (non-net metered) Class I renewable energy projects without long-term contracts on a scale that will allow renewable energy generation to keep up with RPS demand. This is true regardless of the type of developer or the way they finance their projects. With respect to project-financed projects, the lender and tax equity investor interviewed expressed similar opinions with respect to the importance of long-term contracts to their decisions whether to invest in renewable energy projects.

Furthermore, a number of the renewable generation developers stated that the opportunity to bid in forthcoming RFPs–in order to access the contracts they need—is important in their decisions whether to continue project development efforts (such as permitting) in this region.

3. Long-Term Contracts are Not Sufficiently Available in the Absence of Section 83

There is a need for the Distribution Companies to enter into long-term contracts under Section 83 because of a lack of availability in the market of other buyers willing and able to enter into long-term contracts with renewable energy developers. With restructuring and retail electric service

[68] One developer representative stated that the availability of long-term contracts provided a disincentive to build wind projects on a merchant basis and long-term contracts may distort the market. On the other hand, he thought his management would require long-term contracts in order to hedge market price risks before building any new wind projects.

competition, the ability and willingness of load serving entities ("LSEs" a/k/a retail electric suppliers) to enter into long-term contracts to support new renewable generation has been extremely limited. This is unsurprising since they enter into contracts to provide retail electric service with terms ranging from several months to up to three years or so. Since they have little certainty regarding the amount of their loads or the pricing of RECs going out more than three years, they are very reluctant to enter into contracts beyond that period. If they were to consider such contracting, purchase prices would be sharply discounted, making the economics for developers very difficult or infeasible. Developers report the same is true for power marketers or energy trading firms that are not LSEs. Municipal utilities have been purchasers of energy and RECs under long-term contracts, but their needs, willingness and capacity to purchase are relatively small relative to the RPS requirements.69 Other states in the region have long-term contracting programs, but they are focused on meeting the RPS needs of their states.[70]

4. *The DPU Has Recognized the Need for Long-Term Contracts*

The DPU addressed the questions of the need for long-term contracts to support financing of the renewable energy projects for which the Distribution Companies had signed PPAs. In each case, the DPU found that the PPAs would facilitate financing of the proposed projects. The DPU's findings on the importance on long-term PPAs to financing renewable energy projects were based on evidence submitted by the Distribution Companies, which was primarily obtained from the project developers, and was largely uncontested.

With regard to the PPA between National Grid and Cape Wind, the Department stated:

> The evidence demonstrates that a project like Cape Wind would face difficulty in attracting financing without a predictable source of revenues with a creditworthy entity. The predictable revenue stream of a long-term contract will help overcome obstacles to

[69] In Massachusetts, municipal utilities are not subject to the RPS requirements.

[70] In 2009, the Rhode Island Legislature enacted the Long-Term Contracting Standard for Renewable Energy, which requires National Grid to acquire under long-term contract renewable energy resources equivalent to 90 MW multiplied by a 100% capacity factor. R.I. Gen. Laws § 39—26.1 *et seq*. The Maine Public Utilities Commission periodically issues RFPs for long-term contracts for renewable energy resources pursuant to Title 35-A M.R.S.A. § 3210-C , which authorizes the Commission to direct investor-owned transmission and distribution utilities to enter long-term contracts for capacity resources and associated energy. Connecticut currently has a long-term contracting mandate but for certain renewable energy projects no larger than 2 MW. See http://www.cl-p.com/Home/SaveEnergy/GoingGreen/Renewable_Energy_Credits. In November 2012, the New England Stages Committee on Electricity ("NESCOE") issued a work plan for coordinated renewable power procurement among the New England states pursuant to a July 2012 New England Governors' Resolution directing NESCO to implement such a work plan, with a goal of issuing a solicitation by December 2013. http://www.nescoe.com/uploads/WORK_PLAN_Final_Nov_2012.pdf . This process is still in a state of development.

> Cape Wind obtaining financing. Ultimately, National Grid relied upon the representations of Cape Wind, the sole entity that has been in contact with the financing community about the Cape Wind project, that the terms of PPA-[1], will be sufficient for Cape Wind to obtain financing.
>
> Similarly, Cape Wind provided evidence that PPA-1 will facilitate the financing of its project. Cape Wind testified that long-term contracts are critical to enhancing the likelihood of obtaining financing because such contracts identify the buyer of the output and provide for a revenue stream. Although Cape Wind acknowledges that, historically, projects were developed and financed without a long-term contract in place, it has been five to ten years since that was the industry norm for the development of energy projects. Cape Wind also testified that, in the current capital markets, it is unlikely that a renewable or even a non-renewable energy project will be developed without a long-term contract for a major share of the output. As such Cape Wind testified that long-term contracts are necessary to secure financing for the Cape Wind project. No party refuted the testimony of National Grid and Cape Wind that long-term contracts help the developers of renewable energy generation projects obtain financing, and we find such testimony credible and reliable.71

With regard to the NSTAR PPA with Blue Sky East, LLC and the Bull Hill project, NSTAR showed that the proposed 15-year PPA would permit the project owner "to provide 20 to 40 percent project equity and raise capital by issuing long-term debt at attractive financing terms," and without a long-term contract Blue Sky East, LLC "may obtain less favorable financing terms for Bull Hill or no financing at all."72 The Department also found that the predictable revenue stream of a long-term contract was required to allow Iberdrola, which uses balance sheet financing, to commit its internal funds to constructing the Groton Wind and Hoosac Wind projects.73

Similarly, with regard to the proposed Passadumkeag wind project, the Department found that based on information provided by the developer, WMECO demonstrated that "a predictable source of revenue with a creditworthy entity like an electric distribution company will assist

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[71] *Id.* at 51-52. With respect to this and other Department decisions on facilitation of financing, footnotes, as well as references to testimony and exhibits, are omitted for ease of reading.

[72] NSTAR Electric Company, D.P.U. 11-05, at 20.

[73] *Id.*

Noble Wind in financing the wind facility and that, without such a long-term contract, obtaining such financing would be very difficult."[74]

Unitil entered into a 15-year REC-only PPA with BBHP, a developer that proposed to expand the generating capacity of an existing hydroelectric facility by 2 MW. The Department found that the PPA will facilitate the financing of the expansion facility based on the positive role the PPA would have on BBHP to obtain debt financing on suitable terms.

> BBHP maintains that without an executed contract for a facility's output, it is difficult for a developer to secure lender financing under current market conditions. Specifically, BBHP maintains that lenders assign little value to the revenue stream associated with RECs, despite forward market projections. Without a contract with a creditworthy counterparty for the output of the facility, BBHP states that those lenders that do offer financing often require restrictive terms such as higher interest rates and debt service coverage ratios, that are unacceptable to a borrower.[75]

The Department requires a showing of the role of a long-term PPA in terms of the developer's willingness and ability to finance a proposed project under Section 83. The Department's decisions to date demonstrate the importance of long-term contracts to financing new renewable energy projects.

5. *The Results of the Solicitations Show the Value of Long-Term Contracts*

Importantly, four projects arising out of the Section 83 process have been built or are in construction, with three wind plants likely to be completed by year's end. The owners of those projects have confirmed that the Section 83 PPAs were critical in terms of their ability to finance and build those projects—regardless of whether they have utilized project finance (2 projects) or balance sheet financing (2 projects). For Iberdrola, which uses balance sheet financing, the PPAs were critically important in terms of corporate management's decision to make the capital investment in constructing the projects. For the other two projects, the PPAs allowed the project owners to obtain debt on a project-financed basis. The two other developers with PPAs have expressed that the PPAs provide them with the capability to obtain project financing—in industry parlance, the PPAs are "financeable."

[74] Western Massachusetts Electric Company, D.P.U. 11-12 (2011) at 14-15.

[75] Fitchburg Gas and Electric Company d/b/a Unitil, D.P.U. 11-30 (2011) at 14.

6. *Energy Stakeholders Stated the Importance of Long-Term Contracts*

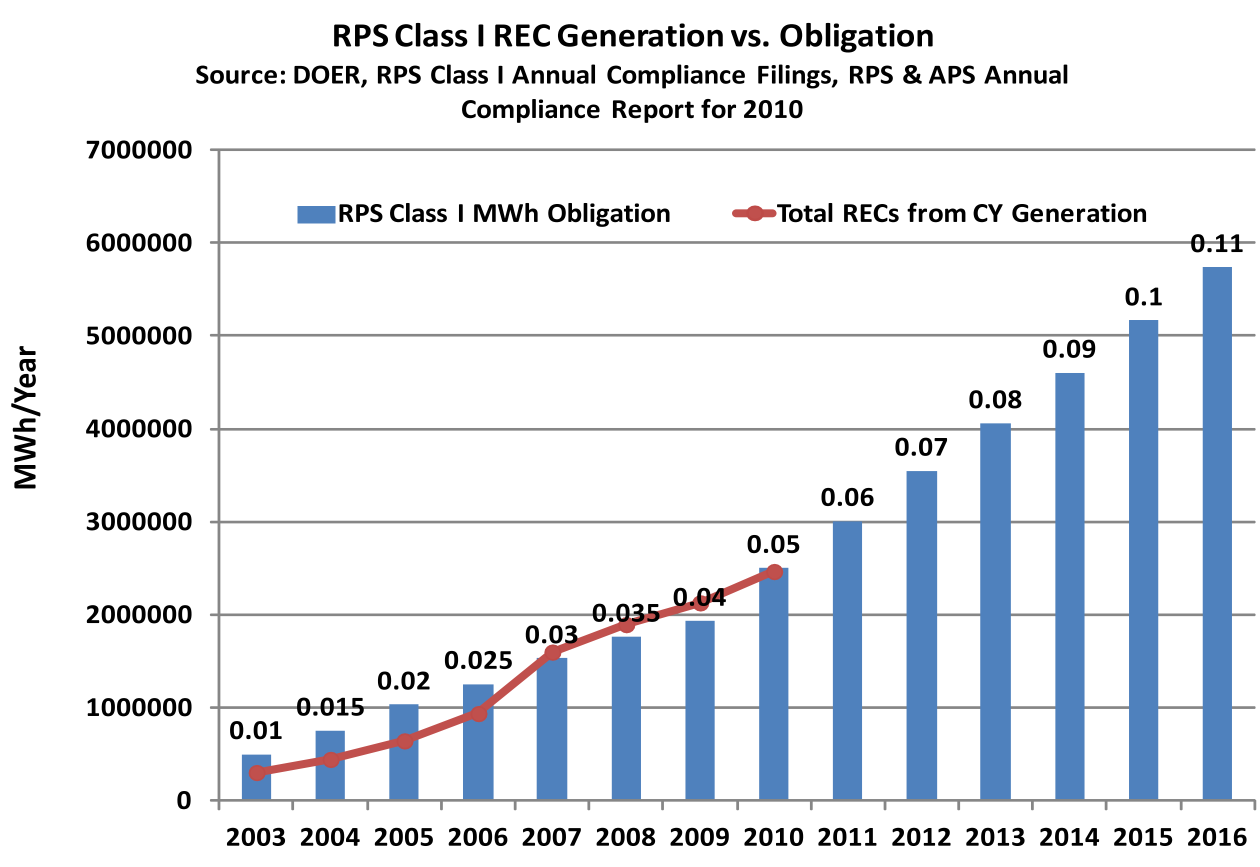
In addition to the renewable energy developers and investors iinterviewed for this report, the other energy stakeholders interviewed stated their understanding that long-term contracts are important to the financing and construction of new utility-scale renewable energy projects. This included all of the Distribution Companies and each of the organizational stakeholders, although the organizational stakeholders had disagreements or concerns regarding various aspects of the way Section 83 was implemented.[76]

C. Impacts of Long-Term Contracts

Without a long-term contracting mandate, such as Section 83 or Section 83A, it is highly likely that Class I renewable energy supply will not keep up with the Commonwealth's RPS goals, with their annual increase in demand. According to Robert C. Grace, President of Sustainable Energy Advantage, LLC and a leading renewable energy regional market analyst, the RECs produced by the projects with Section 83 PPAs should produce enough RECs over the next two years to bring REC supply in line with Massachusetts Class I RPS demand, which should have the effect of reducing REC market prices from their current high levels. However, with the continuing increase in RPS demand, additional PPAs will need to be executed under the new Section 83A in order to keep RPS supply and demand in balance for the next several succeeding years.[77] A graph showing historical RPS supply and demand through 2010 and projected RPS demand through 2016 is shown below.

[76] Issues pertaining to the reasonableness of the implementation of Section 83 are addressed in Section IV of this report.

[77] The extent to which REC prices will be constrained through the addition of new renewable generation will depend on the extent to which supply will catch up with demand.



Without the construction of new renewable energy projects, there will be a shortage of Class I RECs to meet the increasing annual demand for Class I RECs, resulting in the inability to meet the Commonwealth's renewable energy goals embodied in the RPS. If supply fails to keep pace with demand, market REC prices will gravitate toward the Alternative Compliance Price, which each year will increase with the rate of inflation, resulting in higher rates to Massachusetts ratepayers. The contracts executed under Section 83, to the extent the associated projects are built, will result in the creation of new RECs to be produced each year, contributing to meeting the RPS goals. If supply keeps up with demand, the new PPAs and projects should have a dampening effect on REC market prices. Of course, if there is a shortage, retail electric suppliers (a) will not be able to purchase a portion of their renewable energy requirements but will be required to pay the ACP instead and (b) will pay higher prices for their REC market purchases, which will probably be priced at a small discount to the ACP. Failure to meet Massachusetts' renewable energy goals will result in both higher greenhouse gas emissions and higher costs to Massachusetts ratepayers.

A byproduct of the increase in renewable energy production brought about by long-term contracts is suppression of wholesale electric energy prices. This occurs when zero cost or low cost energy generation is added to the markets, which has the effect of reducing wholesale energy market clearing prices.[78] While the magnitude and duration of this effect is subject to debate, the Department has recognized that wind energy and other renewable energy resources have a substantial energy price suppression effect.[79] This is a benefit also recognized by many of the interviewees questioned on this topic.

The Section 83 PPAs will also lock in the cost of energy and RECs (and also capacity for several of the contracts) purchased under the PPAs. The impacts, based on the cost recovery mechanisms approved by the Department, is that the Distribution Company's basic service customers will benefit by having an assured quantity of RECs (subject to amounts produced by the projects) for 10 to 15 years while the larger group of distribution customers will receive a hedge with respect to the price of energy they purchase, including the price associated with RECs required to serve them by their retail electric suppliers.

Under the plans of the Distribution Companies approved by the DPU, the Distribution Companies will resell energy purchased under the PPAs into the market. Their distribution customers will pay the net charge or receive the net benefit based on the difference between the contract price and the market price. The Distribution Companies will retain the RECs in order to serve their basic service customers, but they will charge their basic service customers the market price for the RECs. The distribution customers will receive the benefit of, or incur the burden of, the difference between the PPA REC contract price and the market price paid by the basic service customers. In this manner, the competitive balance between basic service and competitive retail electric service will be maintained, the Distribution Companies (and their distribution customers) avoid transaction charges associated with selling RECs into the market, and the net charge or credit for the RECs will be assigned to the distribution customers, who will also be responsible for paying the 4% remuneration to the Distribution Companies.[80]

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[78] In ISO-New England, energy clearing prices are set by the bid submitted by the highest cost (or marginal) generator dispatched to meet demand. Low variable cost generators typically submit bids below that of the marginal generators, tending to displace higher cost generation, resulting in a lower clearing price for electric energy. While this effect is usually modest on a $/MWh basis, the impact is generally widespread, so the total effect can be quite substantial.

[79] Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, D.P.U. 10-54 (2010) at 108-131; NSTAR Electric Company, D.P.U. (November 26, 2012) at 70-78.

[80] For example, assume that the PPA has a REC price of $35 and an energy price of $55/MWh and 100,000 MWh is produced in the course of a year. The Distribution Company for the particular year buys RECs for its basic service customers at an average price of $60. The 100,000 RECs produced by the Project are used by the Distribution Company to provide basic service. However, the basic service customers are charged at the market rate--$60 per

The impact of the REC purchase is multifold. Basic service customers benefit primarily because their need for purchasing RECs from the market is reduced, having a dampening effect on REC purchase prices. For distribution customers, the long-term REC purchase serves as a hedge of their exposure to long-term REC prices (as well as energy prices). If REC prices continue to stay high, as is currently the case, distribution customers will likely receive credits against their utility bills.

IV. The Reasonableness and Effectiveness of the Section 83 Solicitations

In this section, we address the manner in which the Section 83 requirements were implemented in the solicitation processes carried out in 2009-2011 following the passage of the Green Communities Act and the opportunities for improvements in future solicitations to be conducted under Section 83A. Since Section 83A mandates competitive bidding processes in the future, our focus will be on the review of the RFP process under Section 83 and to a lesser extent on the negotiation process which led to the PPAs with Cape Wind. We address the following issues in turn:

- The robustness of the response and the adequacy of outreach to prospective bidders;
- Eligibility issues and fairness of the process;
- The extent to which the selected projects selected satisfied statutory and regulatory objectives and requirements;
- Viability of the projects receiving contracts;
- The reasonableness of the bid evaluation and selection process;
- The effectiveness and efficiency of utilizing a DOER-coordinated solicitation process
- Fairness of the Model PPA and its use.

REC. The difference--$25 per REC for 100,000 RECs or $2.5 million is allocated to the distribution customers as a credit to their bill. However, the energy purchased from the wind project is sold into the market at an average price of $40/MWh, which results in a $1.5 million charge to distribution customers. Finally, the Distribution Company receives 4% of its total payments as remuneration—which would be $90/MWh * 100,000 MWh * 4% or $360,000. The net benefit to the Distribution Company's distribution customers in this year would be $2,500,000 (RECs) minus $1,500,000 (energy) minus $360,000 (remuneration) for a total of $640,000.

A. Robustness of the RFP Response and Adequacy of Outreach to Prospective Bidders

The overall result of the RFP process was a very robust response from the renewable energy development community. The three distribution companies that executed PPAs pursuant to the Amended RFP each received over 100 proposals from developers with respect to over 70 renewable energy projects. There was considerable overlap, as many developers submitted proposals to multiple distribution companies. NSTAR reported that it received proposals from over 2,500 MW of renewable generation with an average annual output of 7.5 million MWh/year, representing more than 11 times the upper end of its procurement target (3% of distribution load). The ratio of bid MWh to procurement target MWh was even higher for WMECO and Unitil.

The Amended RFP was distributed to more than 300 individuals and renewable energy developers from a list compiled by the distribution companies and DOER. This followed several earlier wide-scale distributions of RFP documents related to filings before the Department of the Initial RFP and Amended RFP and an earlier circulation of draft RFP documents for comment. In addition, notice of the Amended RFP was sent to a variety of trade publications.

The extensive response to the Amended RFP is evidence that there was a strong renewable energy industry demand for long-term contracts for energy and/or RECs, bidders generally must have felt that they had a reasonable opportunity to obtain a contract, and that the outreach activities of the Distribution Companies and DOER were very effective. Another factor is that developers had the ability to submit the same proposal, with or without modifications, to multiple prospective buyers at the same time, which mitigated the time and cost associated with developing proposals compared to responding to multiple solicitations with different requirements at different times.

B. Eligibility Issues and Fairness of the Process

Following the TransCanada lawsuit, the Department removed the in-state geographic limitation on bidder eligibility and requested the Distribution Companies to submit a revised RFP. Most interviewees had a favorable view on removal of the geographic limitation, which led to a very robust bidder response to the Amended RFP and very competitive pricing from experienced developers with viable projects.

In the Amended RFP, the Distribution Companies, in coordination with DOER, solicited proposals from Class I Renewable Generation Units. There were a number of bids from solar PV projects. RECs from these projects were valued as Class I RECs.

Allco Renewable Energy Limited ("Allco"), a bidder of solar PV projects, filed complaints against NSTAR, WMECO and Unitil claiming, among other things, that the Distribution Companies were required to treat their bids as offers from Solar Carve-Out Renewable Generation Units and to value the renewable energy attributes as Solar Carve-out Renewable Energy Credits ("S-RECs") under the Massachusetts RPS and DOER's regulations, but failed to do so. S-RECs have higher values than Class I RECs. The Distribution Companies and DOER opposed Allco's complaint on a number of grounds. The Department granted the Distribution Company's motions to dismiss.[81] The Department found that (a) RPS Class I Renewable Generating Units under DOER's regulations do not include Solar Carve-out Renewable Generation Units, (b) a new facility using solar PV may elect qualification as either a Class I Renewable Generation Unit or a Class I Solar Carve-out Renewable Generation Unit, but not both, (c) Allco's proposals to bid S-RECs from Class I Solar Carve-out Renewable Generation Units were ineligible under the Amended RFP, and (d) the Distribution Companies were not required under Section 83 to consider proposals from Solar Carve-out Renewable Generation Units or to value S-RECs.[82]

There are a number of programs in Massachusetts that have fostered solar PV development in the Commonwealth, including net metering for projects below specified kW thresholds, the RPS Solar Carve-out, the Solar Credit Clearinghouse Auction, and rebates from the Massachusetts Clean Energy Center.

Representatives of the Solar Energy Industries Association ("SEIA") have stated that a long-term contracting program for larger projects above the size eligible for net metering would help these projects to obtain financing and reduce costs to customers. Solar PV projects tend to have higher costs than large grid-scale wind projects and are unlikely to be cost-competitive if they must compete as Class I units with eligibility to sell only Class I RECs. The SEIA representatives suggested a SREC-only Section 83 solicitation or a Section 83 solicitation where the evaluation criteria are revised so that solar PV project would be more competitive or where diversity would be given more weight. The Conservation Law Foundation also would like to see more emphasis on diversity and less emphasis on price, specifically a weighting less than 80 percent. Under the Amended RFP, diversity was a factor to be considered in the third stage of the evaluation process.

National Grid decided to negotiate a PPA with Cape Wind, with the Department approving the process and the resulting PPA under Section 83. Some parties, including DOER, the Attorney

[81] Allco Renewable Energy Limited, D.P.U. 11-23, 11-24, 11-25 (October 19, 2011).

[82] *Id.*

General, and the Conservation Law Foundation, advocated for both the negotiation process and approval of the PPA based on the unique benefits of the Cape Wind project based on, among other things, the project's size and location, energy price suppression benefits, greenhouse gas reduction benefits, and employment benefits. Other parties, including AIM, NEPGA, ANPS, and several other interviewees objected to the non-competitive nature of the process and the high cost of the project's energy, capacity, and RECs. In our opinion, the individual negotiation process was appropriate under Section 83, especially given the unique characteristics of Cape Wind and its ability to contribute to RPS compliance, but will have little relevance for future solicitations under Section 83A, which mandates competitive bidding.

Future solicitations under Section 83A are likely to resemble the Section 83 Amended RFP process in many respects. The Amended RFP process was designed and executed in a manner that provided for equal access to prospective bidders of information and documents pertaining to the RFP. The Distribution Companies and DOER developed a common website, www.massachusettsrenewableenergyrfp.com, which was utilized to post the Amended RFP, bidder response forms, the Model PPA, answers to questions from prospective bidders, and other pertinent material.

Once bids were submitted, the Distribution companies were individually responsible for the evaluation and bid selection of proposals submitted to them. Our review of the evaluation and bid selection process on an after-the-fact basis did not disclose any example of undue discrimination against, or undue preference for, any particular bidder, although there are some questions regarding the reasonableness of the bid evaluation and selection process, which are addressed in Section IV.E below. There is one matter of particular concern regarding NSTAR's administration of the RPF process, which pertained to the manner in which it used the Model PPA in its contract negotiations on one particular issue, which is addressed in Section IV.G below. On the whole, however, there was a general consensus that the RFP process was designed and conducted in a manner that was fair to eligible bidders and was well run.

C. The Extent to Which Statutory and Regulatory Objectives Were Achieved

A solicitation process can reasonably be evaluated based on the extent to which the selected proposals satisfy the objectives of the procurement effort. Based on Section 83 of the GCA and the Department's applicable regulations, key objectives are cost-effectiveness and the extent to which the resulting contracts will facilitate financing of proposed projects.

In terms of cost-effectiveness, all of the proposals receiving contracts in the Amended RFP process were evaluated as being substantially below market over the contract term based on the common price forecast used in the economic evaluation. This is indicative of the quality of the bids received, but is also reflective of the market price forecast itself. In a competitive bidding context, the most important consideration is how the bids compared to each other in the economic evaluation and the process by which bids were solicited.[83] The proposals that received contracts in the Amended RFP process reflected lower prices than originally bid due to requested price rebids sought by the Distribution Companies. Also, the prices were either the lowest or among the lowest received. Hence, the process worked well to obtain economically competitive contracts.

In addition, each of the projects receiving contracts were new, to-be-constructed projects (or expansions of projects) and the developers made a showing that obtaining a long-term contract would facilitate financing of the proposed project. This included a spectrum of project types (wind and hydro), product types (energy + RECs, energy + RECs+ capacity, and RECs only), and financing strategies (traditional project financing and balance sheet financing). At the same time, all of the minimum statutory requirements were satisfied (contributions to reliability, employment additions, and moderation of system peak load).

Hence, it is fair to conclude that the Amended RFP was successful in that the projects that received contracts appeared to satisfy the applicable statutory and regulatory objectives. As a general matter, the structure of the Amended RFP evaluation framework was conducive to achieving this result. Minimum statutory requirements had to be satisfied in the first stage evaluation while price was the predominant factor in the quantitative score received in the second stage evaluation. Cost-effectiveness, whether the proposed PPA would facilitate financing of the proposed project, ranking in the second stage evaluation, and risk associated with project viability were all factors to be considered by the distribution companies in the third stage evaluation process.

Moreover, by providing contracts to planned renewable energy facilities, as opposed to existing facilities, the Amended RFP solicitation process will contribute to the success of the Massachusetts RPS program by facilitating the construction of new Class I RPS-compliant facilities, which will provide incremental supply of RECs to help meet increasing RPS obligations in upcoming years as well as providing a price hedge for distribution company customers.

[83] In some competitive solicitations, the most economically attractive bids may be evaluated as being above market. This does not necessarily mean that the bids are economically unattractive, since the bids themselves are likely to be better evidence of market value than the forecast against which the bids are compared. Nor are we suggesting that the Levitan forecast was unreasonable or too high.

The Department, through its analysis of the Cape Wind project and PPA with National Grid, determined that the Cape Wind project satisfied all of the minimum statutory criteria and provided considerable additional benefits, including enhancing reliability, increasing employment, and reducing future environmental compliance costs.

D. Project Viability

Another key criterion in evaluating the success of a solicitation process is the extent to which the projects receiving contracts are likely to be constructed—in other words, how viable are the projects for which contracts were obtained? Indicia of project viability are the experience and track record of the developer, the developer's financial strength and access to capital, its proposed use of commercial technology, and the development status of the project and prognosis for finalizing the development process, including obtaining required permits.

All of the developers that received contracts are experienced renewable energy developers and plant owners with significant financial strength and/or access to capital—Iberdrola, First Wind, ArcLight, and Noble.84 All proposed to use commercial technology. The proposed projects were all at the middle to late stage of development and without any apparent fatal flaws.

These matters are taken into consideration in the bid evaluation process in several ways. In the first stage evaluation, a developer must demonstrate site control, its proposed use of commercial technology, that it has a reasonable project schedule, that it has the ability to finance the proposed project and that it has some relevant experience. The extent to which a developer can demonstrate these capabilities and show project development progress are non-price factors considered in the second stage evaluation. Finally, risk associated with project viability is a factor for consideration in the third stage evaluation.

The structure of the Amended RFP process appropriately required that the indicia of project viability be considered in the evaluation process. The ultimate measure of success is whether a high percentage of the projects under contract are constructed (and are built within a reasonable time). Here, four of the five projects with PPAs arising out of the Amended RFP have already been built or are in construction. That is a very good success rate. Cape Wind,

[84] Noble has assigned the PPA it executed with WMECO to Quantum Utility Generation, a company that has considerable financial strength and key employees with substantial industry experience.

meanwhile, has recently obtained DPU approval for its second PPA, now has two contracts for 77.5 percent of its output, and is actively pursuing financing of its project.

E. Reasonableness of the Distribution Companies' Evaluation and Bid Selection Process

On the whole, the distribution companies reasonably implemented the bid evaluation and selection framework set forth in the Amended RFP and the protocols for price and non-price evaluation developed by the distribution companies in consultation with DOER. There were, however, a number of perceived shortcomings or perceived shortcomings, some of which were raised by the Attorney General's expert witnesses, with suggestions for future improvements, in the DPU proceedings. We address them below.

1. Guidance regarding "Facilitation of Financing"

The Attorney General suggested that future RFPs should provide more guidance on what is meant by whether a long-term contract would "facilitate financing" and how it should be considered in the evaluation process.

One of the challenges in designing the RFP was to address the requirement in Section 83 that to be eligible for a long-term contract a renewable energy facility had to be built on or after January 1, 2008 while being responsive to the Department's directive that in allocating the limited resource of Section 83 contracts "the distribution companies should be mindful of the express language of the statute, which calls upon distribution companies 'to enter into cost-effective long-term contracts to *facilitate the financing* of renewable energy generation.'" D.P.U. 10-58 at 6 citing GCA Section 83 (emphasis in original). The distinction is that a planned facility might need a long-term contract in order to be financed and constructed but an existing facility, albeit recently built, would not in most conceivable circumstances have a similar need.

The Amended RFP addressed this issue in the following ways:

- In the first stage evaluation, a facility must have a commercial operation date on or after January 1, 2008 (or represent a capacity expansion or a repowering with a commercial operation date on or after January 1, 2008);85

[85] Section 2.2.2.2.b.

- In the second stage evaluation, the distribution company is to consider the extent to which a PPA will facilitate financing (this would have a small impact on the quantitative second stage score, which includes price and non-price factors);86
- In the third-stage evaluation, one of the factors that a distribution company could consider in ranking bids and making bid selections was "whether the proposed PPA will facilitate financing of the proposed project;"87
- Bidders were asked to characterize the development status of the facility (i.e., whether it was planned, in operation, or in construction) and whether the project had already obtained financing and if not, explain how obtaining a long-term PPA would help the bidder to obtain financing for its proposed project.88

The approach reflected in the Amended RFP was, in our opinion, appropriate at the time. However, subsequent to the Distribution Companies' issuance of the Amended RFP, the Department, in its decision on the National Grid-Cape Wind PPA, determined that "Section 83 requires electric distribution companies to demonstrate, as a threshold matter, that a proposed long-term contract will facilitate the financing of a renewable energy project."89 Section 83A has similar language regarding "facilitation of financing." Hence, in future solicitations under Section 83A, the RFP should require a showing in the first evaluation stage—as a threshold matter—that a proposed PPA will facilitate financing of the proposed project.

Based on our knowledge of the process and interviews with the Distribution Companies, it appears that the companies had somewhat differing interpretations of what did or did not constitute "facilitation of financing" in specific contexts. In future DOER-coordinated solicitations, bid selection will be a joint process so there should be a more uniform approach in applying this requirement.

The Department's opinions have helped to clarify that "facilitation of financing" is a threshold requirement and that there are a variety of ways developers, whether they plan to use project financing or balance sheet financing, can demonstrate that a long-term PPA will assist them in their ability to finance their proposed project. One utility representative opined that despite the instructions in the Amended RFP some of the bidders did not seem to understand the type

[86] Section 2.3.2.2.

[87] Section 2.4.

[88] Bidder Response Package Sections 5.8 and 7.12.

[89] Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, D.P.U. 10-54 (November 22, 2010) at 50.

of responses they were being asked to provide or the consequence if they did not provide a response indicating that a long-term PPA was important to financing construction of their proposed facility. Providing more specific guidance in the next RFP consistent with the Department's decisions would be helpful. Making "facilitation of financing" a stage one threshold requirement would convey that it is a requirement, not just an evaluation factor.90

2. *Economic Evaluation Criteria*

The Amended RFP price evaluation had two components:

- A comparison on a $/MWh basis of (a) the total cost of the products proposed (energy, RECs, and if accepted by a distribution company, capacity) to (b) the estimated market value of these products, using a common price forecast (70 points);
- The relative degree of front-loading of the proposed pricing (10 points).91

Front-Loading

The Attorney General's witnesses suggested elimination of the separate assignment of 10 points for ascertaining degrees of front-loading—(a) because it should be reflected in discounting bid prices anyway and (b) because, as applied by NSTAR and WMECO, no distinction was created between bids, almost all of which received a score of 10.

The specific method to evaluate frontloading was not included in the Amended RFP. It was developed subsequently by the distribution companies and DOER as part of the bid evaluation protocol. The evaluation metric gave 10 of 10 points to any bid that had a flat or escalating shape (i.e., it was not frontloaded).[92] With regard to NSTAR's and WMECO's bid evaluations (which used the agreed-upon frontloading cost evaluation methodology), all or almost all of the bids submitted received 10 points. Consistent with industry practice the price bids were all flat or escalating over the contract term. The

[90] In fact, NSTAR in Section 2.2.2.6 of its RFP for long-term contracts for SRECs issued in July 2012 has made it a stage one requirement that the bidder demonstrate that obtaining a long-term contract will facilitate the financing of its proposed project. http://www.nstar.com/docs3/energy_supplier/long-term/srec-rfp.pdf.

91 The weighting between $/MWh cost/benefit and front-loading analysis was not specified in the RFP itself. The front-loading criterion was requested by one of the distribution companies out of concern that a bidder might propose a declining price structure over the contract term instead of a flat or increasing price structure. DOER's consultants had not seen this evaluation criterion in a RFP; to the extent it is addressed, it is usually specified that a declining price structure is not allowable. However, since the impact of this criterion was expected to be minimal (typically, bid price structures are flat or increasing), DOER consented to this approach as part of an overall package.

[92] This was a compromise between those that wanted a frontloading evaluation criterion and those that did not.

net effect of using the levelization price metric was neutral—it had no impact on the evaluation results. The Attorney General's recommendation for elimination of the front-loading criterion is meritorious. For future RFPs, frontloading should be eliminated as a price-related evaluation criterion. Rather, there should be an additional requirement that proposed pricing either be a flat $/MWh amount for the contract term or a $/MWh amount that is increasing over the contract term. This would be consistent with industry practice and would avoid confusion. The net $/MWh cost evaluation factor alone should be sufficient to evaluate the price of bids relative to their market value.

Net Economic Benefit Evaluation Metric

The Distribution Companies in coordination with DOER used a levelization approach to calculate the above/below market value of the bids on a $/MWh basis. Economic evaluation of PPA proposals utilizing a comparison of costs to benefits (or market value) on a levelized basis is a common way that the economics of proposals are evaluated in solicitations involving long-term contracts for renewable energy.[93] This evaluation metric allows for assessment of proposals with different quantities and different terms in a consistent and comparable basis and is easy to use.

On the other hand, net present value of the net costs or benefits of a proposal is also a common and accepted economic evaluation metric (and was used by the DPU in assessing the net benefits of the Cape Wind PPA). Under the Section 83A process, the Distribution Companies will be required to confer with the Attorney General and DOER regarding the "choice of contract methods and solicitation methods." Hence, this issue can and should be addressed at an early stage in the development of a future RFP.

3. *Consistency in Evaluation Methods*

Unitil did not apply the methodologies for the price evaluation developed by the distribution companies and DOER, but used its own approach. While this practice was not material to the result, in the future, Distribution Companies should take steps to make sure that their evaluation methodologies conform with methodologies they have agreed to follow before they begin evaluation of bids. This should be easier to monitor in the context of future joint solicitations under Section 83A.

[93] In solicitations in California, Arizona, Delaware, Oklahoma, and Hawaii, a comparison of costs to benefits on a levelized basis (or simply a levelized cost approach in one instance) has been used for the economic evaluation. See, e.g. PG&E 2011 Renewables RFO Protocol, Attachment K at 3: "Market valuation considers how an Offer's costs compares to its benefits, from a market perspective. . . . Costs and Benefits are each quantified and expressed in terms of present value (January 1, 2011 dollars) per MWh. Market Value is Benefits minus Costs, and is expressed in terms of levelized price, that is, present value per MWh (2011 dollars and 2011 MWh)," http://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/renewables2011/index.shtml,

4. Approach to Short Listing

The Attorney General's witnesses suggested that future RFPs specify either minimum bid scores or minimum target quantity of bids or some other criteria for selecting a short list and a description of how the short list would be used in inviting rebids and in final contract selection. They also suggested that future RFPs specify when bid updates will be allowed (or not allowed).

Generally, electric utilities in renewable energy solicitations have considerable discretion in terms of how many bids should be short listed and whether or not they should seek refreshed bids from the short list or some subset of the short list. However, it is important that the distribution companies exercise their discretion in a reasonable manner. In future solicitations, we suggest that the RFP specify that distribution companies may seek refreshed bids from either its entire short list or a subset of top-ranked bids on the short list. This would be consistent with the Department's comment in its NSTAR decision that "Going forward, where electric distribution companies determine that it is appropriate to solicit refreshed bids, the companies should ensure that all qualified bidders are allowed the opportunity to refresh bids."94 Since under Section 83A, the bid selection process for a DOER-coordinated solicitation will be a joint process, not one conducted by each individual Distribution Company, there should be uniformity in the short listing process. Again, the Attorney General as well as DOER will be able to provide their input to the Distribution Companies as part of the consultative process.

5. Project and Contract Size vs. Distribution Company Need

In their bid selection decisions, the smaller distribution companies, WMECO and Unitil, gave strong consideration to project and contract size relative to need. Both selected proposals for the entire output of the products purchased from projects that were small enough such that the level of purchases did not greatly exceed the 3 percent minimum purchase requirement under Section 83. In support of this approach, WMECO pointed to the "portfolio effect" criterion in the third stage evaluation—"portfolio effect: the value of diversity of resources—by size and type of resources."95 Unitil indicated a concern about contracting with a larger project for substantially less than the full output of the project. While not explicitly articulated by Unitil, there is a risk—called "subscription risk"—that a project that sells substantially less than the entire output of a project might not be able to finance and construct the project.

[94] NSTAR Electric Company (August 19, 2011) at 44 n. 42.

[95] Amended RFP Section 2.4.

In our opinion, the focus of the smaller utilities in the third evaluation stage on selecting proposals that reasonably fit their need was reasonable in the particular context.83 However, it will not be relevant (or will at least be far less important) in the context of future joint solicitations since, under Section 83A joint solicitations, the Distribution Companies will enter into contracts with the winning bidders for their proportionate share of the products sold by the project based on their relative distribution loads.

F. The Regulatory Path, Stakeholder Input and Value of a DOER-Coordinated Solicitation Process

Under Section 83 and the Department's applicable regulations, there were two regulatory approval processes for the solicitation—(1) Department review and approval of the timetable and method of solicitation contained in the RFP; and (2) Department review and approval of the PPA executed as a result of the RFP. In fact, because of the changes to the Department's regulations removing the Massachusetts geographical requirement as a result of the TransCanada litigation, the Department reviewed and approved both the Initial RFP and then the Amended RFP.

The Department granted approvals of the RFPs in a relatively timely fashion, providing a degree of flexibility to the distribution companies and DOER, a joint petitioner with the Distribution Companies. Indeed, DOER's role as an active participant in the process of designing the RFP, and the expertise it contributed, was a basis for the Department deferring to the judgment of the joint petitioners in the RFP design phase.

All three distribution companies that executed PPAs received approvals from the Department, with no opposition with respect to whether the PPAs merited approval. The regulatory process proceeded smoothly with relatively few issues for Department decision. DOER supported approval of all of the PPAs. The relative ease of the regulatory process was reflective of the quality of the RFP and evaluation framework, the distribution companies' efforts to fairly and effectively execute the solicitation process in accordance with the Amended RFP, and the role played by DOER.[96]

Aside from the value added to the regulatory process, use of a DOER-coordinated solicitation process provided other advantages as well as some disadvantages. First, it required a substantial investment of time and effort by the distribution companies and DOER to

[96] Future involvement by the Attorney General in the RFP development process (through its consultative role) could further assist in facilitating and expediting the regulatory review process.

collaborate to produce a single RFP document, bid response package, bid evaluation protocol, and Model PPA. The process might have taken additional time compared to individual Distribution Company solicitation processes. On the other hand, this collaborative process likely contributed to a better quality solicitation than would likely have been the case if each distribution company pursued individual solicitations. Each of the parties made major contributions to the process. DOER contributed consultants experienced in utility solicitations for renewable energy under long-term contracts, who, among other things, drafted RFP documents. National Grid and NSTAR provided outside counsel, who provided considerable assistance with regard to the Model PPA and regulatory matters. All of the Distribution Companies provided considerable internal resources, with substantial collective experience, expertise, and insight. DOER provided personnel to oversee the process.

DOER provided other contributions as well. It met with representatives of the development community to obtain input on a Model PPA and through its efforts was able to address some developer concerns through development of the Model PPA. The opportunity for formal stakeholder input into the process was extensive—with (1) the DPU's promulgation of regulations under Section 83, (2) approval of the timetable and method for solicitation and execution of contracts for the Initial RFP, (3) the DPU's amendment of its regulations following the TransCanada lawsuit, (4) approval of the timetable and method for solicitation of contracts for the Amended RFP, and, (5) with the DPU's approval of executed contracts. However, the informal stakeholder input process employed by the Distribution Companies, in coordination with DOER, even before the proposed Initial RFP was submitted to the DPU (as well as DOER's stakeholder efforts to obtain input regarding the Model PPA) provided additional opportunity for stakeholder input.

There were other benefits for the Distribution Companies. By utilizing a common price forecast, the cost of which was shared among the distribution companies, the cost associated with the conduct of the solicitation was mitigated. Moreover, a common market price forecast was helpful to parties and the Department in the regulatory process.

All in all, the Distribution Companies expressed satisfaction with the RFP process and its results.

From a developer standpoint, the conduct of a solicitation by multiple utilities simultaneously using the same procurement documents enabled developers to reach a larger market at a lower cost of time, effort, and money than if utilities had conducted their own independent solicitations.

Future joint solicitations under Section 83A should entail joint bid selection and more consistency among the Distribution Companies in the bid evaluation process and in contract terms.

G. The Model PPA and Risk Allocation Issues

1. *Overview*

It took considerable time and effort for the Distribution Companies and DOER to agree on a Model PPA. As a result, the Model PPA was not submitted to the Department at the time the distribution companies and DOER sought approval of the Initial RFP. The joint petitioners stated, and the Department agreed, that submission of a Model PPA for Department review and approval was not required under Section 83 and the Department's regulations. Moreover, requiring such a review would have entailed substantial delays in the solicitation process.

Under the circumstances, the approach taken with respect to the Model PPA was appropriate. However, in the future, it would provide for a more transparent process if a Model PPA was submitted to the Department for informational purposes at the same time approval was sought for the timetable and method of solicitation and execution of contracts. We appreciate and agree with the Department's reluctance to step in and decide disputes over terms to be included in a Model PPA when bidders have the ability to propose exceptions to the Model PPA when they submit their bids. However, by providing a Model PPA solely on an informational basis, if there are any particularly critical issues associated with a Model PPA, such as provisions that would clearly make a PPA non-financeable, and which cannot reasonably be addressed through the process of proposing exceptions when bids are submitted, there would be the opportunity for interested parties to raise the issues and for the Department to address them, if necessary, before the bid submittal process begins. Since the Model PPA would not be submitted for approval, the DPU would be under no obligation to consider issues raised by stakeholders regarding contract provisions unless the Department decided to do so.

Based on our interviews, the general assessment was that the Model PPA was a fair document as a basis for receiving offers. Also, the Distribution Companies were viewed as acting responsibly for the most part in response to suggested contract changes proposed by bidders.

2. *Change in RPS Law*

There was, however, one notable exception pertaining to NSTAR's actions with respect to the change in law provisions regarding RPS qualification. After considerable discussions, the

Distribution Companies and DOER agreed on Model PPA provisions whereby (1) the Seller represents and warrants that it shall be an RPS Class 1 Renewable Generation Unit qualified by DOER to participate in the RPS program (Section 7.2(g)), but (2) if there is a change in law affecting qualification as a RPS Class 1 Renewable Generation Unit, "Seller shall only be required to use commercially reasonable efforts to ensure that all Energy provided by Seller to Buyer from the Facility under this Agreement meets the requirements for eligibility pursuant to the RPS after that change in Law." (Section 4.7(b)). The concept is that if the Legislature or DOER changed the RPS qualification rules in a manner that was commercially reasonable for a seller to comply with, for example, if new reporting requirements were mandated, the seller would be responsible for compliance. If, on the other hand, new rules, by way of example required all wind turbines to have a minimum size of 4 MW each, a wind farm would not be required to replace all its 2 MW wind turbines with 4 MW wind turbines—the expense would not be a commercially reasonable one.

Both in the Initial RFP and Amended RFP, the Model PPA with these provisions was posted on the RFP website. In the process of dealing with shortlisted bidders, NSTAR took the position that the sellers, not the buyers, must take the change in law risk.

NSTAR indicated that it changed course on this issue in the context of DOER's deciding to change its regulations regarding qualification standards for biomass facilities. However, it appears that all of the projects that were subject to NSTAR's negotiation approach were wind projects in ISO-New England, for which there would appear to be low change in law risk.

NSTAR signed two PPAs with Iberdrola and one PPA with First Wind, in which the seller takes the change in law risk.[97] If the wind projects no longer qualify for the RPS, NSTAR would no longer have to pay for the RECs. However, NSTAR would still be responsible for paying for the energy under the PPAs.98

As indicated before, Iberdrola finances its projects based on its own balance sheet. It did not plan on seeking project debt or tax equity. Iberdrola apparently made the decision that the risk of a change in RPS law affecting its projects' RPS qualifications was very low and it made commercial sense to assume the risk.

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[97] See Transcript pp. 175-181, hearing held on June 14, 2011, NSTAR Electric Company, D.P.U. 11-05/11-06/11-07.

[98] *Id.*

First Wind planned to use project financing, like most other developers. In connection with NSTAR's reallocation of the change in law risk, First Wind adjusted the allocation between energy and REC prices so that the REC price dropped substantially (and the energy price increased).99 This reduced First Wind's change in law risk since NSTAR would continue having the obligation to purchase the energy. However, NSTAR would continue having the obligation to purchase energy, which could be at an above-market price.

There are several concerns regarding NSTAR's negotiation approach. Change in RPS law provisions are material terms in a Model PPA and bear upon financeability for project-financed projects, cost to ratepayers for this risk to be assumed by sellers, and competitive balance between the small minority of bidders capable of balance sheet financing and the large majority of bidders planning to use project financing. First, it is poor practice in a competitive bidding process to solicit bids based on a specified risk allocation framework and then to change that once bids are received in a manner disadvantageous to bidders. This is especially true after the Model PPA, including the provisions at issue, had been agreed upon after substantial discussions with DOER and the other Distribution Companies.

Based on the interviews conducted as well as our general industry knowledge, debt and tax equity investors would be reluctant to invest in a project where the seller would assume the change in RPS law risk or if they would consider investing, would not consider (or would sharply discount) the expected revenues associated with the sale of RECs. This would likely result in lower amounts of debt which would need to be replaced with higher cost equity. In addition, interest rates and other financial terms may become more expensive. The result would likely be a substantial risk premium that ratepayers would incur. The reason lenders (and tax equity) will not assume this risk is that it is beyond the control of the seller, especially since the change can be made by regulation or statute—it is essentially a political risk.

Use of this provision in the future would likely have the following effects:

- Potentially reducing participation by bidders;
- Increasing bid prices;
- Providing a competitive advantage for the few firms that don't use project finance at the expense of the many who rely on project finance.

Section 83 (and Section 83A) has a provision that is pertinent.

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[99] *Id.* at 177.

> If the RPS requirements of said section 11F of said chapter 25A [the RPS law] should ever terminate, the obligation to continue periodic solicitations to enter into long term contracts shall cease, but contracts already executed and approved by the department of public utilities shall remain in full force and effect.

While not dispositive of how the change in law risk should be addressed under Section 83 PPAs, the requirement that sellers' contract rights should continue in effect even if the RPS is terminated suggests that this should include the right to continue to receive payment for RECs even a project no longer qualifies under the RPS due to a change in law that is not the fault of the seller. That is the case with the National Grid and NSTAR PPAs with Cape Wind as well as the PPAs executed by WMECO and Unitil, which incorporated the Model PPA provisions regarding RPS change in law risk.

It is possible that a bidding process could include tradeoffs between price and allocation of change in law risk by allowing bids with and without the RPS risk being assumed by the seller.100 However, it would be counterproductive to either (a) require the seller to assume the RPS change in law risk or (b) try to reallocate the risk to the seller after bids are submitted where, under the Model PPA, the buyer assumes the risk. While it does not appear that the ultimate result of the Amended RFP was substantially impacted by NSTAR's behavior, this practice should not be repeated in the future.

3. *Federal Tax Benefits*

The Model PPA allocated to the seller the risk of the seller's inability to qualify for the PTC, the ITC, or other federal tax benefit. Under the Model PPA, the seller would be required to perform even if it was ineligible for a federal tax benefit. The reason for this was that at the time the Initial RFP and Amended RFP were developed, it appeared that bidders would or should have a very good chance of their projects going in service before the then-deadline for the PTC and ITC—December 31, 2012. It was thought that projects that were late in going into service or were on a later time schedule should be prepared to take the risk (although the Model PPA provisions were subject to negotiation).

[100] While bidders should be able to bid different energy and REC prices, the Distribution Companies should be able to require a readjustment of the prices to reflect the relative estimated value of the different products. It is not the same for a seller to accept the RPS change in law risk through a REC price offer that is 10% percent of its total price as compared to a REC price offer that is 40% of its total price. There is a difference in risk allocation, as a practical matter.

This issue was addressed very differently in the Cape Wind PPAs with National Grid and NSTAR. Due to the long lead time of the Cape Wind project and its longer construction period compared to onshore wind projects, it made sense for the risk of non-eligibility for federal tax benefits to be allocated between the parties by price adjustment provisions in the PPA.[101]

In light of the uncertainty regarding extension of the PTC (and other federal tax benefits), the length of any extension, and any changes to the form or amount of the PTC, the Distribution Companies in consultation with DOER and the Attorney General should consider what the best approach should be for addressing this matter in terms of the structure of the RFP and the Model PPA. This is a non-trivial issue as the value of the PTC, assuming that it is extended in its current form, is $22/MWh for 10 years increasing with inflation on a pre-tax basis (the after-tax value is higher).

IV. Conclusion

Based on the interviews conducted and our knowledge of the electric power industry, our major conclusions are as follows:

- Long-term contracts for energy and RECs are, and will be, necessary for Massachusetts to meet the goals under its RPS with respect to Class 1 Renewable Generating Units;
- There are an insufficient number of creditworthy entities willing to enter into long-term contracts with renewable energy developers for multi-MW grid-connected projects in the absence of a mandate on the Distribution Companies to do so;
- The long-term contracting requirements under Section 83 reasonably fulfill the need for long-term contracts and reasonably support the renewable energy goals of the commonwealth;
- There is a general consensus that the RFP process employed under Section 83 was, for the most part, well conducted, fair and produced good results;
- There were a few shortcomings in the RFP process under Section 83, which can, and are likely to be, rectified in future Section 83A solicitations, because of modifications to future solicitation processes mandated by Section 83A and as a result of "lessons learned" from the Section 83 procurements.

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[101] Specifically, in the Cape Wind PPA, the base price is increased if on the date the Facility is placed in service the Facility qualifies for the PTC but not the ITC. There is a further increase in price if the Facility qualifies for neither the PTC nor ITC. See Cape Wind First Amendment to PPA-1, Appendix X to Exhibit E.

APPENDIX

QUALIFICATIONS OF CONSULTING TEAM

Peregrine Energy Group, Inc. is an energy consulting company specializing in renewable energy and energy efficiency. Founded in Boston in 1992, Peregrine's practice is based on a thorough understanding of energy policies, regulations, programs, markets and data. The senior professionals of the firm have many years of experience with utility regulation and the competitive energy markets in New England in general, and with renewable energy in particular.

Paul Gromer, President and Founder of Peregrine Energy Group, is a former Commissioner of DOER. He has been an active participant in Massachusetts regulatory and policy proceedings, including the introduction of competitive markets in the restructuring of the electric industry as well as recent policies to stimulate development of generation from renewable projects.

Francis Cummings of Peregrine is an energy economist and a former Policy Director for the Massachusetts Technology Collaborative, where he led the development of the state's program ("MGPP") that conducted competitive solicitations for long-term purchase and option contracts for RECs to support renewable project financing. His experience also includes financial analysis of the impact of power purchase contracts and power prices on project financing for renewable power generation. Mr. Cummings has served as a Principal at KEMA Consulting, where he directed XENERGY multi-client studies and engagements in renewable energy and state energy policy. He has been a Member of the EPRI Public Advisory Group on Energy Efficiency/Smart Grid (2007 - 2009). He has testified or prepared energy policy and regulatory filings in Massachusetts, Connecticut, Maine, New York and New Jersey. He is a graduate of Harvard College.

New Energy Opportunities, Inc. ("NEO") is a consulting firm with a focus on the procurement and sale of electric power and other products from generation facilities, especially those using renewable resources. Barry Sheingold, President of NEO, has over 20 years of experience in the design and structuring of long-term contracts for the purchase and sale of electric power, the design of competitive procurements, evaluating bids, and oversight of solicitations, including considerable experience with competitive procurements for long-term contracts involving renewable energy projects.

NEO has provided consulting assistance in the renewable energy field in a variety of capacities and has worked for different types of clients. In 2009-2011, Mr. Sheingold advised the Massachusetts Department of Energy Resources regarding its collaboration with the Commonwealth's investor-owned utilities on a joint renewable energy RFP under Section 83 of the Green Communities Act. Previously, Mr. Sheingold advised the Massachusetts Technology Collaborative and the New York State Energy Research and Development Authority regarding the design of competitive procurement processes for the purchase of Renewable Energy Certificates under long-term contracts. He also conducted surveys of bidders and other stakeholders in the context of evaluation of these solicitations. In addition, he has advised the Delaware Public Service commission with respect to the development of a Solar Renewable Energy Credit procurement pilot program for Delmarva Power & Light Company.

Mr. Sheingold has performed an independent evaluator function for renewable energy RFPs in several states, including California, Oklahoma, Delaware and Hawaii, where he has authored or co-authored a variety of evaluation reports on solicitation processes over the past several years. More recently, he has served as Independent Evaluator with respect to Southern California Edison Company's implementation of California's Combined Heat and Power Program.

Mr. Sheingold has also served as an expert witness on a variety of matters, including testimony with respect to wind energy power purchase agreements in Oklahoma and Delaware, a proposed biomass cogeneration project in Nova Scotia, a proposed fuel cell project in Delaware, confidentiality issues with regard to a competitive bidding process for conventional generation in Quebec, and a long-term solar renewable energy credit purchase contract in Delaware.

Mr. Sheingold has advised a variety of private and public clients in the negotiation of electric power transactions and in related due diligence involving the sale or purchase of electric power products, project sales, and other commercial transactions.

Mr. Sheingold was formerly Senior Vice President of Citizens Power LLC, the nation's pioneering electric power marketing company, where he served in a senior business capacity after serving as General Counsel. Previously, Mr. Sheingold worked for Delmarva Power and Light Company, Delmarva's independent power development affiliate, Delmarva Capital Technology Company, and the Federal Energy Regulatory Commission. He is a graduate of Boston College Law School (*cum laude*) and New College, now the honors college of the Florida university system.