The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 13-146 February 26, 2014

Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval by the Department of Public Utilities of: (1) six long-term contracts for procurement of renewable energy and renewable energy credits from six individual wind projects, pursuant to St. 2008, c. 169, § 83A and 220 C.M.R. § 21.00 et seq.; and (2) a long-term renewable contract adjustment mechanism tariff, M.D.P.U. No. 239.

D.P.U. 13-147

Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid for approval by the Department of Public Utilities of: (1) six long-term contracts for procurement of renewable energy and renewable energy credits from six individual wind projects, pursuant to St. 2008, c. 169, § 83A and 220 C.M.R. § 21.00 et seq.; (2) a renewable energy recovery provision tariff, M.D.P.U. No. 1221; and (3) a basic service adjustment provision tariff, M.D.P.U. No. 1222.

D.P.U. 13-148

Petition of NSTAR Electric Company for approval by the Department of Public Utilities of: (1) six long-term contracts for procurement of renewable energy and renewable energy credits from six individual wind projects, pursuant to St. 2008, c. 169, § 83A and 220 C.M.R. § 21.00 et seq.; and (2) a long-term renewable contract adjustment mechanism tariff, M.D.P.U. No. 164B.

D.P.U. 13-149

Petition of Western Massachusetts Electric Company for approval by the Department of Public Utilities of: (1) six long-term contracts for procurement of renewable energy and renewable energy credits from six individual wind projects, pursuant to St. 2008, c. 169, § 83A and 220 C.M.R. § 21.00 et seq.; and (2) a long-term renewable contract adjustment mechanism tariff, M.D.P.U. No. 1051B.

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TABLE OF CONTENTS

I. INTRODUCTION

On September 20, 2013, Fitchburg Gas and Electric Light Company d/b/a Unitil ("Fitchburg"), Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("National Grid"), NSTAR Electric Company ("NSTAR") and Western Massachusetts Electric Company ("WMECo") (collectively, the "Distribution Companies") separately filed petitions with the Department of Public Utilities ("Department"), pursuant to the Green Communities Act, St. 2008, c. 169, § 83A ("Section 83A")[1] and 220 C.M.R. § 21.00 et seq., seeking approval of five 15-year power purchase agreements ("PPAs" or "proposed contracts") and one 20-year PPA for renewable energy and renewable energy certificates ("RECs") from the following six renewable energy projects under development: (1) Iberdrola Renewables, LLC's ("Iberdrola") Wild Meadows Wind project located in New Hampshire; (2) Iberdrola's Fletcher Mountain facility located in New Hampshire; (3) Evergreen Wind II, LLC's ("Evergreen Wind") Oakfield Wind facility located in Maine; (4) Blue Sky West, LLC's ("Blue Sky West") Bingham Wind project located in Maine; (5) Exergy Development Group's ("Exergy") Passamaquoddy wind facility located in Maine; and (6) Exergy's Peskotmuhkati wind facility located in Maine.

The petitions also include requests for approval of tariffs which provide for the recovery of costs associated with the PPAs. Specifically, Fitchburg requested the approval of proposed tariff M.D.P.U. No. 239, National Grid requested the approval of proposed tariffs M.D.P.U.

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1 Section 83A was added to the Green Communities Act ("GCA") by an Act Relative to competitively Priced Electricity in the Commonwealth, St. 2012, c. 209, § 36.

No. 1221 and M.D.P.U. No. 1222, NSTAR requested the approval of proposed tariff M.D.P.U. No. 164B, and WMECo requested the approval of proposed tariff M.D.P.U. No. 1051B. The Department docketed the Fitchburg petition as D.P.U. 13-146, the National Grid petition as D.P.U. 13-147, the NSTAR petition as D.P.U. 13-148, and the WMECo petition as D.P.U. 13-149.

On October 24, 2013, the Distribution Companies submitted a Joint Motion to Withdraw the four contracts associated with Iberdrola's Fletcher Mountain project ("Joint Motion to Withdraw, October 24, 2013"). On November 21, 2013, the Distribution Companies submitted a Joint Motion to Withdraw the eight contracts associated with Exergy's Passamaquoddy and Peskomuhkati projects and to amend the petitions and supporting testimony to reflect the request to withdraw twelve of the proposed contracts from Department consideration ("Joint Motion to Withdraw, November 21, 2013"). On November 27, 2013, the Department granted each of the joint motions filed by the Distribution Companies. The twelve remaining contracts for which the Distribution Companies are seeking approval are for 15-year terms and represent a total of 1,176,717 megawatt-hours ("MWh"), or approximately 2.5 percent of the combined service territory load of the Distribution Companies (Exh. DPU-4-18 (supp.)). Wild Meadows Wind, Oakfield Wind and Bingham Wind have a total nameplate capacity of 409.5 MW (Exh. JU (rev.) at 32-34)

Pursuant to separate notice duly issued for each of the four docketed matters, the Department conducted a combined procedural conference on October 9, 2013; however, the Department did not formally consolidate the four proceedings. The Attorney General filed a Notice of Intervention in each of the proceedings pursuant to G.L. c. 12, § 11E(a). The

Department granted the petitions to intervene in each of the proceedings filed by the Department of Energy Resources ("DOER"), Evergreen Wind and Blue Sky West.[2] The Department granted the petition to intervene in NSTAR Electric Company, D.P.U. 13-147, filed by the Cape Light Compact ("CLC"). The Department denied the petitions to intervene in each of the proceedings filed by Lilli-Ann Green et al. on behalf of seven ratepayers. The Department granted the Associated Industries of Massachusetts limited participant status in each of the proceedings, as requested. On November 6, 2013, the Department granted the late-filed petition to intervene in each of the proceedings of Lightship Energy LLC on the sole issue of the consideration of transmission costs in the bid evaluation process. Hearing Officer Ruling on Lightship Energy LLC Petition to Intervene at 5 (November 6, 2013).

On October 2, 2013, pursuant to G.L. c. 12, § 11E(b), the Attorney General filed a Notice of Retention of Experts and Consultants in each of the proceedings. On October 10, 2013, the Department approved the Attorney General's request for a combined total of $150,000 to retain experts and consultants for the four proceedings.

On October 23, 2013, pursuant to separate notice duly issued in each of the four docketed matters, the Department conducted a combined public hearing at its offices in Boston, Massachusetts. Members of the public recommended, among other things, that the Department examine the consideration of transmission costs in the bid evaluation process. See Tr. of Public Hearing (October 23, 2013). In addition, certain members of the public voiced opposition to the

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[2] Both Evergreen Wind and Blue Sky West are wholly-owned subsidiaries of First Wind Holdings, LLC ("First Wind"). Accordingly, First Wind has submitted post-hearing briefs in the proceedings that represent the joint position of Evergreen Wind and Blue Sky West.

siting of the renewable energy facilities that would provide energy and RECs under the proposed contracts.[3] See Tr. of Public Hearing (October 23, 2013).

On December 11, 2013, the Department conducted a combined evidentiary hearing. In each of the proceedings, the Distribution Companies sponsored the joint testimony of the following witnesses: Jeffrey S. Waltman, manager of planning supply for Massachusetts regulated operating companies of Northeast Utilities ("NU"), NSTAR and WMECo; Corinne M. Abrams, manager of environmental transactions, energy procurement for National Grid; and Robert S. Furino, director, energy contracts for Unitil Services Corporation.[4] With respect to cost recovery issues, each of the Distribution Companies separately sponsored the testimony of the following witnesses: (1) Robert S. Furino for Fitchburg; (2) Scott M. McCabe, principal program manager, New England electric pricing, for National Grid USA Service Company, Inc., for National Grid; and (3) Richard D. Chin, manager of rates for the Massachusetts regulated operating companies of NU, for NSTAR and for WMECo. The Attorney General sponsored in each of the proceedings the joint testimony of Dr. Jürgen Weiss and Judy W. Chang, both principals at The Brattle Group.

On December 23, 2013, the Distribution Companies, the Attorney General, DOER, and First Wind submitted initial briefs in the four proceedings, and CLC filed a brief in NSTAR Electric Company, D.P.U. 13-148. On January 8, 2014, the Distribution Companies, DOER and

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3 The Department notes that any issues related to the siting of energy facilities in jurisdictions outside of Massachusetts are beyond the scope of these proceedings and, indeed, beyond the jurisdiction of the Department.

4 The Department will refer to the joint pre-filed testimony of the Distribution Companies and the revised joint pre-filed testimony of the Distribution Companies as Exh. JU and Exh. JU (rev.), respectively.

First Wind submitted reply briefs in the four proceedings, and CLC submitted a reply brief in NSTAR Electric Company, D.P.U. 13-148. The record for all four dockets consists of a total of 173 exhibits, including responses to 121 information requests and to six record requests.

II. DESCRIPTION OF THE WIND FACILITIES

The proposed contracts are for the total output of three wind energy generating facilities to be located in New Hampshire and Maine.

A. Wild Meadows Wind

Wild Meadows Wind will consist of 23 wind turbine generators, each with a capacity of 3.3 megawatts ("MW"), for a total project capacity of 75.9 MW (Exh. DPU-7-4).[5] The expected commercial operation date of the facility is December 31, 2016 (Exh. JU (rev.) at 34). Wild Meadows Wind will interconnect to the regional electricity grid operated by ISO-NE in New Hampshire (Exh. DPU-7-5).

B. Bingham Wind

Bingham Wind will consist of 62 wind turbine generators, each with a capacity of three MW, for a total project capacity of 186 MW (Exh. DPU-7-4). The expected commercial operation date of the facility is December 31, 2016 (Exh. JU (rev.) at 34). Bingham Wind will interconnect to the regional electricity grid operated by ISO-NE in Maine (Exh. DPU-7-5).

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5 As indicated earlier, the three facilities have a total nameplate capacity of 409.5 MW (Exh. JU (rev.) at 33-34). The Department notes according to Exh. JU-11, at 1, Wild Meadows Wind project will produce 74 MW resulting in a total nameplate capacity of only 407.6 MW; however, the Distribution Companies have also stated that the Wild Meadows Wind project will consist of 23 wind turbines, each with a capacity of 3.3 MW (i.e., 75.9 MW total), and this total is reflected in the revised joint testimony (Exh. JU (rev.) at 7-8).

C. Oakfield Wind

Oakfield Wind will consist of 48 wind turbine generators, each with a capacity of 3.075 MW, for a total project capacity of 147.6 MW (Exh. DPU-7-4). The expected commercial operation date of the facility is December 31, 2015 (Exh. JU (rev.) at 34). Oakfield Wind will interconnect to the regional electricity grid operated by ISO-NE in Maine (Exh. DPU-7-5).

III. DESCRIPTION OF THE PROPOSED CONTRACTS

A. Products and Pricing Structure

Under the proposed contracts with Iberdrola, Evergreen Wind and Blue Sky West, the Distribution Companies will purchase, for a term of 15 years, two products associated with the output of the Wild Meadows Wind, Oakfield Wind, and Bingham Wind generating facilities: (1) energy; and (2) RECs (Exhs. JU (rev.) at 33-34; JU-1(A) at 15; JU-1(B) at 15; JU-1(C) at 17; JU-1(D) at 15; JU-3(A) at 15; JU-3(B) at 16; JU-3(C) at 16-17; JU-3(D) at 14; JU-4(A) at 14; JU-4(B) at 14; JU-4(C) at 16; JU-4(D) at 14). The price for energy and RECs[6] is fixed for the life of each of the twelve proposed contracts (Exhs. JU (rev.) at 33-34; JU-1(A) at 7, 13, 15, 27, 55; JU-1(B) at 7, 13, 15, 27, 55; JU-1(C) at 8, 14, 17, 29, 62; JU-1(D) at 7, 13, 15, 27, 55; JU-3(A) at 7, 12, 15, 26, 58; JU-3(B) at 7, 12, 16, 28, 66; JU-3(C) at 8, 14, 16-17, 28, 66; JU-3(D) at 7, 12, 14, 26, 58; JU-4(A) at 7, 12, 14, 26, 54; JU-4(B) at 7, 12, 14, 26, 54; JU-4(C) at 8, 13, 16, 28, 61; JU-4(D) at 7, 12, 14, 26, 54).

B. Additional Provisions

Each of the PPAs includes the following provisions. First, the project developers bear all risk associated with eligibility for tax credits (Exhs. JU (rev.) at 40; JU-1(A) at 29; JU-1(B)

[6] The proposed contracts often refer to combined energy and RECs as Products (see, e.g., Exh. JU-3 (C) at 17).

at 29; JU-1(C) at 31; JU-1(D) at 29; JU-3(A) at 28; JU-3(B) at 28; JU-3(C) at 31; JU-3(D) at 28; JU-4(A) at 28; JU-4(B) at 28; JU-4(C) at 30; JU-4(D) at 28). Second, the facilities must qualify as Class I renewable generation sources under the Massachusetts Renewable Portfolio Standard ("RPS") before the Distribution Companies are obligated to buy any output from the facilities, and the Distribution Companies are not obligated to purchase RECs if the facilities fail to maintain qualification as RPS Class I sources (Exhs. JU (rev.) at 40; JU-1(A) at 21, 23; JU-1(B) at 21, 23; JU-1(C) at 22-25; JU-1 (D) at 21, 23; JU-3(A) at 19, 21; JU-3(B) at 19, 21; JU-3(C) at 22, 24; JU-3(D) at 19, 21; JU-4(A) at 19, 21; JU-4 (B) at 19, 21; JU-4(C) at 21, 23; JU-4(D) at 19, 21). Third, the Distribution Companies are obligated to buy energy and/or RECs from the facilities only up to the maximum contract quantities and are not required to make any additional payments in the event that the facilities operate below contract maximum or do not operate at all (Exhs. JU (rev.) at 41; JU-1(A) at 22-23; JU-1(B) at 22-23; JU-1(C) at 24-25; JU-1(D) at 22-23; JU-3(A) at 21; JU-3(B) at 21-22; JU-(C) at 23-24; JU-3 (D) at 21-22; JU-4(A) at 21-22; JU-4(B) at 21-22; JU-4(C) at 23-24; JU-4(D) at 21-22). Fourth, the project developers are responsible for the costs to deliver the energy to the Delivery Point that is on the ISO-NE Pool Transmission Facility ("PTF"), which includes all applicable charges associated with transmission interconnection, service and delivery charges, related ISO-NE administrative fees, and other Federal Energy Regulatory Commission ("FERC") approved charges (Exhs. JU-1(A) at 24-25, JU-1 (B) at 24-25, JU-1(C) at 26, JU-1(D) at 24-25, JU-3(A) at 23, JU-3(B) at 23, JU-3(C) at 26, JU-3(D) at 23, JU-4(A) at 23, JU-4(B) at 23, JU-4(C) at 25, JU-4(D) at 23. Fifth, the Distribution Companies are entitled to delay damages, as specified in the contracts, if the facilities fail to meet critical milestones[7] (Exhs. JU-1(A) at 7, 17-18 (Confidential); JU-1(B) at 7, 17-18 (Confidential); JU-1(C) at 7, 19-20 (Confidential); JU-1(D) at 7, 17-18 (Confidential); JU-3(A) at 7, 16-17 (Confidential); JU-3(B) at 7, 16-17 (Confidential); JU-3(C) at 7, 18-19 (Confidential); JU-3 (D) at 7, 16-17 (Confidential); JU-4(A) at 7, 16-17 (Confidential); JU-4 B) at 7, 16-17 (Confidential); JU-4(C) at 7, 18-19 (Confidential); JU-4(D) at 7, 16-17 (Confidential)).

IV. STANDARD OF REVIEW

Section 83A of the Green Communities Act requires the electric distribution companies to enter into jointly solicited cost-effective long-term contracts to facilitate the financing of renewable energy generation, subject to the review and approval of the Department. Thus, as an initial matter, each electric distribution company must demonstrate that the long-term contract facilitates the financing of the renewable energy generating source to which the contract applies.[8]

In addition, Section 83A and the Department's applicable regulations set forth specific findings that the Department must make in order to approve a long-term contract for renewable energy generation. In particular, pursuant to Section 83A and 220 C.M.R. § 21.05(1), the Department must determine that the renewable energy generating resource: (1) provides

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7 Some examples of critical milestones are securing all permits, remaining in good financial standing in order to construct the wind facility, and achieving commercial operation by a designated date (Exhs. JU-1(A) at 7, 16; JU-1(B) at 7, 16; JU-1(C) at 7, 18; JU-1(D) at 7, 16; JU-3(A) at 7, 15; JU-3(B) at 7, 15; JU-3(C) at 7, 17-18; JU-3(D) at 7, 15; JU-4(A) at 7, 15; JU-4(B) at 7, 15; JU-4(C) at 7, 17; JU-4(D) at 7, 15).

8 To be an eligible renewable energy generating source, Section 83A requires that the generator: (1) have a commercial operation date, as verified by DOER, on or after January 1, 2013; and (2) be qualified by DOER as eligible to participate in the RPS program and sell RECs under the program, pursuant to G.L. c. 25A, § 11F. St. 2008, c. 169, § 83A; 220 C.M.R. § 21.05(1).

enhanced electricity reliability within the Commonwealth; (2) contributes to moderating system peak load requirements; (3) is cost effective to Massachusetts electric ratepayers over the term of the contract; and (4) where feasible, creates additional employment and economic development in the Commonwealth. The Department must take into consideration both the potential costs and benefits of such contracts and approve a contract only upon a finding that it is a cost-effective mechanism for procuring low-cost renewable energy on a long-term basis taking into account the factors outlined in Section 83A. St. 2008, c. 169, § 83A; 220 C.M.R. § 21.05(1).

Additionally, the public interest constitutes an overarching consideration in the Department's fulfillment of its regulatory and ratemaking duties. Attorney General v. Dep't of Telecomm. & Energy, 438 Mass. 256, 268 (2002). Accordingly, in our review of long-term contracts for renewable energy generation under Section 83A, the Department also considers whether the contract is in the public interest.[9] Fitchburg Gas and Electric Company d/b/a Unitil, Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, NSTAR Electric Company, and Western Massachusetts Electric Company, D.P.U. 13-57, at 22 (2013). This review includes a determination of whether the companies properly followed the bid evaluation process contemplated in the request for proposals that the Department approved in

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9 Pursuant to G.L. c. 164, § 94A ("Section 94A"), an electric or gas distribution company must obtain Department approval to enter into a contract for the purchase of electricity or gas covering a period in excess of one year. The Department has construed our approval under 94A to require a determination that the contract is consistent with the public interest. See, e.g., NSTAR Electric Company, D.P.U. 07-64-A at 58 (2008); New England Electric System/Nantucket Electric Company, D.P.U. 95-67, at 21-22 (1995), citing New England Power Company, D.P.U. 1204 (1982). The Department's public interest review in this proceeding will therefore satisfy the review otherwise performed under Section 94A.

D.P.U. 13-57, and that the companies applied the approved bid criteria, including their analysis of bids. See NSTAR Electric Company, D.P.U. 11-05/11-06/11-07, at 40 (2011). The Department will further consider whether the associated cost recovery method is in the public interest and will result in just and reasonable rates pursuant to G.L. c. 164, § 94. Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, D.P.U. 09-138, at 12 (2009); see also 438 Mass. at 264 n. 13; Boston Edison Company/ComEnergy Merger, D.T.E. 99-19, at 8 (1999), citing Mass. Oilheat Council v. Dep't of Pub. Utils., 418 Mass. 798, 804 (1994); Boston Real Estate Bd. v. Dep't of Pub. Utils., 334 Mass. 477, 495 (1956).[10]

V. SOLICITATION PROCESS

A. Introduction

Section 83A requires the Distribution Companies to undertake competitive solicitations for long-term contracts for renewable energy and/or RECs (Exh. JU (rev.) at 7). The Distribution Companies, after consulting with DOER and the Attorney General, jointly developed a Request for Proposals ("RFP") to solicit bids (Exh. JU (rev.) at 17, 20). In addition, the Distribution Companies jointly did each of the following: (1) issued the RFP; (2) established a standardized framework for evaluation of bids and negotiation of long-term contracts for renewable energy and related products; and (3) evaluated bids and negotiated the long-term contracts (Exh. JU (rev.) at 20-21).

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10 Section 83A also requires the Department to conduct a public interest evaluation for any significant transmission costs included in a bid. See Section 83A; see also 220 C.M.R. § 21.07(3). Here, no such transmission costs were included in the responsive bids and/or the petitions submitted by the Distribution Companies.

The RFP includes various requirements for pricing proposals that bidders must meet in order for a bid to be considered conforming (Exh. JU-7(A) at 15-16). Further, the RFP requires that sellers identify a delivery point for electric energy at an ISO-NE PTF (Exh. JU-7(A) at 15). The RFP also requires that sellers bear all costs to transmit electricity to the Delivery Point (Exh. JU-7(A) at 15).[11]

On March 1, 2013, the Distribution Companies jointly submitted the RFP for Department review and approval. D.P.U. 13-57, at 1-2. On March 29, 2013, the Department approved the timetable and method of solicitation and execution of long-term contracts for renewable energy contained in the RFP, as well as a draft PPA. D.P.U. 13-57, at 25-26. The Department determined that the timetable and method of solicitation and execution for long-term contracts contained in the RFP were consistent with (1) Section 83A; and (2) 220 C.M.R. § 21.00 et seq. D.P.U. 13-57, at 25-26.

On April 1, 2013, the Distribution Companies issued the RFP to over 300 entities (Exh. JU (rev.) at 17, 22). The Distribution Companies and DOER collaborated to create the distribution list for the RFP (Exhs. JU (rev.) at 22; JU-WP(A); AG-1-8).

The Distribution Companies conducted a bidders' conference on April 16, 2013 and hosted a website where potential bidders could submit questions regarding the RFP process (Exh. JU (rev.) at 22). The RFP provided a deadline of April 22, 2013 to submit notices of intent to bid and a deadline of May 6, 2013 to submit bids (Exh. JU (rev.) at 22). The Distribution

11 Pursuant to 220 C.M.R. § 21.07(3), the RFP provides guidance for bids where a bidder seeks to recover transmission costs outside of the PPA through FERC-approved transmission rates (Exh. JU-7(A) at 16). However, as discussed in greater detail below, none of the bids selected by the Distribution Companies sought recovery of transmission costs (Exh. DPU-4-16).

Companies received 112 price offers for 40 distinct projects in response to the RFP (Exh. JU (rev.) at 22). Of these 112 price offers, none proposed to recover transmission costs outside of the PPA through FERC-approved transmission rates (Exh. DPU-4-16). The total potential capacity of the 40 bids was 2,357 MW (Exh. JU (rev.) at 22).

B. Bid Evaluation Process

Pursuant to the RFP, the Distribution Companies jointly performed a three-stage bid evaluation process (Exh. JU (rev.) at 23). In the first stage of the bid evaluation process, the Distribution Companies considered whether the bids satisfied the eligibility,[12] threshold,[13] and other minimum requirements of the RFP[14] (Exh. JU (rev.) at 23-24). The Distribution

12 Eligibility requirements include the following: (1) the bidder must have development rights; (2) the facility must qualify as an RPS Class I Renewable Generation Unit pursuant to 225 C.M.R. § 14.01; (3) the facility must have a commercial operation date on or after January 1, 2013; (4) the proposed contract must provide for the sale of electric energy and/or RECs from an eligible facility and be both unit-specific and unit-contingent; (5) the proposed term of the contract must be between ten and 20 years; and (6) the proposed contract size must be for at least one MW (Exhs. JU (rev.) at 24; JU-7(A) at 9).

13 Threshold requirements include the following: (1) reasonableness of project schedule; (2) site control; (3) viability of the technology; (4) experience of bidder in project development; (5) project contribution to electric reliability in Massachusetts; (6) moderation of system peak load; (7) providing employment and economic development; (8) whether the developer can meet the requirements for development and operating period security; (9) whether the bid was submitted on time; (10) impact of the contract on the distribution company's balance sheet; and (11) the necessity of the contract to facilitate financing of the project (Exh. JU (rev.) at 24).

14 Other minimum requirements include the following: (1) bidder certification that the bid was valid for at least 180 days; (2) conformance of the proposed pricing structure with the RFP; and (3) completeness of the bid package (Exh. JU (rev.) at 24).

Companies state that all of the bids complied with the eligibility, threshold, and minimum requirements (Exh. JU (rev.) at 25).

During stage two of the bid evaluation process, the Distribution Companies evaluated the bids for both price and non-price factors, with price accounting for up to 80 points and non-price factors accounting for up to 20 points (Exh. JU (rev.) at 25-26). The Distribution Companies evaluated price based on the degree to which the net present value ("NPV") of the costs of the contract is expected to be above or below the projected market price forecast of energy and RECs[15] (Exhs. JU (rev.) at 26; DPU-7-1). The project with the most favorable price evaluation received the maximum score of 80 points (Exh. JU (rev.) at 26). All other projects were awarded fewer points, calculated by multiplying the difference between the NPV of the project per MWh of output and the highest valued bid by a fixed multiplier, and subtracting that amount from 80 points (Exh. DPU-7-1).

For each bid that received at least 60 points for price, the Distribution Companies also performed the evaluation of non-price factors (Exh. JU (rev.) at 27). The Distribution Companies evaluated non-price factors based on the following: (1) the ability of the bidder to site and permit the project; (2) the project development status and operational viability; (3) the experience and capabilities of the bidder and the project development team; (4) financing considerations; and (5) any requested exceptions to the model PPA (Exh. JU (rev.) at 26-27). According to the Distribution Companies, 15 projects were scored for both price and non-price

[15] When evaluating bids, the Distribution Companies compared the bids to a long-term price forecast for energy and RECs that a consultant developed (Exhs. JU (rev.) at 26; JU-12 (Confidential)). The forecast includes a forecast of the locational marginal price of energy for each of the New England load zones (Exh. Lightship-1-1).

factors (Exh. JU (rev.) at 27). To calculate non-price points, each Distribution Company developed a preliminary scoring of the proposals using an agreed-upon non-price bid evaluation protocol (Exhs. JU (rev.) at 26-27; AG-2-2). The Distribution Companies then collaboratively established a final consensus score for each bid (Exhs. JU (rev.) at 27; AG-2-2). The Distribution Companies combined the points received for price and non-price factors to determine an overall score and relative ranking for each of the 15 projects scored in stage two (Exh. JU (rev.) at 27-28).

Based on the rankings from the stage two evaluation, the Distribution Companies selected all 15 projects considered in stage two for further consideration (i.e., the "short list")[16] (Exh. JU (rev.) at 28). The Distribution Companies provided each bidder on the short list with an opportunity to improve its overall score by refreshing its price bid (Exh. JU (rev.) at 28). In addition, the Distribution Companies advised bidders of a proposed addition to the draft PPA in response to a revision to the ISO-NE energy market rules that allows for negative locational marginal prices (Exh. JU (rev.) at 29).[17] The purpose of the change to the PPA is to insulate

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16 The short list represented approximately four million MWh of electricity per year, while the Distribution Companies' goal was to purchase annually approximately 850,000 MWh through the RFP (Exh. JU (rev.) at 28).

17 After the Distribution Companies issued the RFP, but before they selected bids, ISO-NE instituted a rule change that allows for negative location marginal prices (Exh. JU (rev.) at 28-29). This rule allows generators to bid into the ISO-NE market at prices up to negative $150/MWh. Thus, at certain times generators could pay to generate electricity. Under the original draft PPA, if the bidders generated electricity at such times, customers would be responsible for additional payments. Under the revised PPA, the generators would be responsible for any additional payments (Exhs. JU (rev.) at 28-29; JU-7(C) at 26; AG-JCJW-1, at 34-35; Tr. 127-129)

customers from potential increased costs as a result of this market rule change, and bidders were advised to take this new risk into account while refreshing their bids (Exh. JU (rev.) at 28-30).

The Distribution Companies state that of the 15 projects on the short list, eleven improved their bid price, two increased their bid price, one withdrew its bid, and another submitted a non-conforming refreshed bid [18] (Exhs. JU (rev.) at 30; DPU-4-15). As a result, 13 bids remained for the stage three evaluation (Exh. JU (rev.) at 30).

According to the RFP, the stage three evaluation uses the stage two evaluation as a guide and allows discretionary consideration of specific criteria[19] (Exh. JU-7(A) at 20). The objective of the stage three evaluation is to select bids that will provide the greatest value consistent with the stated objectives and requirements of in the RFP (Exh. JU-7(A) at 20).

In the stage three evaluation, the Distribution Companies revised the price score for the 13 remaining projects using the same methodology used in the stage two bid evaluation and re-ranked the bids accordingly (Exhs. JU (rev.) at 30; JU-7(A) at 20). Next, the Distribution Companies evaluated the bids based on the specific criteria set forth in the RFP, but did not re-rank the projects as a result of this evaluation (Exhs. JU (rev.) at 31; DPU-5-1).

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18 The Distribution Companies considered the bid non-conforming because it was not consistent with the new PPA provision proposed in response to the changes in the ISO-NE market rules, and therefore excluded the bid from further consideration (Exhs. JU (rev.) at 30; DPU-4-15).

19 The additional evaluation criteria used are: (1) cost effectiveness; (2) risk associated with project viability; (3) the extent to which additional employment and economic development would be created; (4) any unique risks to customers that may be associated with projects proposing to recover transmission costs through transmission rates; and (5) portfolio effect: the value of diversity of resources—by size and type of resource (Exh. JU-7(A) at 20).

The Distribution Companies, after consultation with DOER, elected to pursue PPAs with the six highest-scoring projects which resulted in contracts for a greater percentage of load than the initial quantity targeted in this solicitation (Exh. JU (rev.) at 31). The Distribution Companies state that they based this decision on the: (1) competitive prices from all six projects; (2) concern that future solicitations would not yield such favorable prices given uncertainty regarding the extension of federal tax credits beyond December 31, 2013; (3) diversity of projects (the six projects represented two projects each from three distinct developers); and (4) efficiency gains from negotiating contracts for two projects concurrently with each developer (Exhs. JU (rev.) at 31-32; DPU-4-14).

The Distribution Companies each submitted a PPA for all six projects to the Department for review for a total of 24 PPAs (Exh. JU at 7-8). However, during the course of this proceeding, the Distribution Companies withdrew from consideration the contracts associated with three of the projects. As stated in Section I, above, Iberdrola terminated the PPAs with the Distribution Companies for its Fletcher Mountain project due to failure to receive corporate approval for the project (Motion to Withdraw, October 24, 2013). In addition, the Distribution Companies terminated all PPAs for Exergy's two projects due to Exergy's failure to post a security deposit required under the terms of the PPA (Exh. DPU-7-3). The three remaining projects represent approximately 2.5 percent of the Distribution Companies' combined service territory load obligation (Exh. DPU-4-18 (supp.)).

C. Positions of Parties

1. Attorney General

The Attorney General asserts that the Department's standard of review requires that the Department find that the competitive procurement process was fair, open, and transparent and that the Distribution Companies properly followed the bid evaluation process in the RFP approved by the Department (Attorney General Brief at 6, citing D.P.U. 11-05/11-06/11-07, at 40). The Attorney General states that, overall, the competitive procurement process was an improvement over similar procurements held in response to Section 83, leading to a higher likelihood that the lowest-cost resources will be selected through the process (Attorney General Brief at 12, citing Exh. AG-JCJW-1, at 19-20, 22). The Attorney General further states that the Distribution Companies' bid evaluation process was broadly consistent with the terms of the RFP, with one exception, i.e., the Distribution Companies' failure to adequately consider the costs of potential incremental transmission upgrades or expansions necessary to deliver or integrate the aggregate electricity produced by the selected projects to the ISO-NE grid (Attorney General Brief at 15, 19, citing Exh. AG-JCJW-1, at 7, 23-30, 33-34; Tr. at 201-203).[20]

The Attorney General states that her office did not support the Distribution Companies' treatment of transmission costs during the bid evaluation process proposed during the development of the RFP (Attorney General Brief at 8, citing D.P.U. 13-57, Comments of the

[20] The Attorney General's witnesses argue that the Distribution Companies should have conducted an additional analysis of transmission costs required to interconnect all of the selected projects when it became clear that that many of the selected projects are located in certain transmission-constrained areas of Maine (Exh. AG-JCJW-1, at 7, 23-26).

Attorney General (March 15, 2013)). The Attorney General contends that the Department stated that all parties would have the opportunity to raise relevant substantive issues with respect to the bid evaluation process in Department adjudications of long-term contracts for renewable energy (Attorney General Brief at 14-15, citing D.P.U. 13-57, at 23).

The Attorney General asserts that incremental transmission upgrades or expansions beyond those contemplated in the PPAs may be needed to integrate the selected projects into the ISO-NE grid (Attorney General Brief at 4, 16, citing Exh. AG-JCJW-1, at 7, 24, 25; Tr. at 203-204). The Attorney General argues that this is especially true because some of the selected projects are located in transmission-constrained areas of Maine (Attorney General Brief at 4, 11, 16, 17, citing Exh. AG-JCJW-1, at 7, 24, 25; Tr. at 110). The Attorney General claims that incremental transmission costs could more than double the total cost to ratepayers (Attorney General Brief at 4, 16, citing Exh. AG-JCJW-1, at 26).

The Attorney General claims that if the Distribution Companies had done an analysis of incremental transmission costs, they might have found that a different mix of projects was least cost and cost effective to customers given the magnitude of these potential transmission costs (Attorney General Brief at 15, 17, citing Exh. AG-JCJW-1, at 7, 26-27). The Attorney General argues that it is the Distribution Companies' obligation to evaluate such transmission costs as part of the requirement to demonstrate that they selected the least-cost bundle of contracts that are cost effective (Attorney General Brief at 4, 15, 18).

The Attorney General claims that consideration of certain criteria (i.e., cost effectiveness and the "portfolio effect") in stage three of the bid evaluation process provided the Distribution Companies with discretion to (1) conduct an explicit evaluation of the cost associated with potential incremental transmission upgrades or expansion, and (2) re-evaluate the bids as a result of this analysis (Attorney General Brief at 19-20, citing Exh. AG-JCJW-1, at 34; RR-LDC-2). In particular, the Attorney General notes that the RFP describes the portfolio effect as the "value of diversity of resources—by size and type of resources," but that that "size" and "type" are not defined anywhere in the RFP (Attorney General Brief at 20). Accordingly, the Attorney General argues that these terms are subject to interpretation (Attorney General Brief at 20). The Attorney General asserts that the Distribution Companies' interpretation of "portfolio effect" as applying only to the size and technology type of the resource was not logical (Attorney General Brief at 20, citing Tr. at 117). Rather, the Attorney General argues that "portfolio effect" should include locational diversity, given that project location has a significant impact on the value of the resources selected by the Distribution Companies due to the transmission constraints in Maine (Attorney General Brief at 20).

In addition, the Attorney General asserts that the Distribution Companies were in the best position to evaluate incremental transmission costs, as they had more information about project location and the availability of projects than any individual bidder, and they have transmission affiliates that participate in the transmission planning process (Attorney General Brief at 21, citing Exh. AG-JCJW-1, at 29; Tr. at 188). Also, the Attorney General argues that the Distribution Companies were aware of the need for potential transmission upgrades to integrate the bundle of selected projects and still ignored the transmission costs in their bid evaluation (Attorney General Brief at 22-23, citing Exh. AG-JCJW-1, at 7, 28).

The Attorney General recommends that the Department require the Distribution Companies to submit a compliance filing with an "appropriate analysis" of transmission costs

(Attorney General Brief at 29). The Attorney General maintains that the Department should not approve the proposed contracts until it is able to find that construction of transmission upgrades or expansions beyond those identified in the proposed contracts will not be required to support the proposed facilities (Attorney General Brief at 29).

2. DOER

DOER asserts that the PPAs were the product of a properly conducted competitive procurement process pursuant to an RFP that was previously approved by the Department (DOER Brief at 15; DOER Reply Brief at 4). DOER argues that evaluation of regional transmission impacts is outside of the scope of the RFP process, as approved by the Department (DOER Brief at 17-18). DOER notes that all bids included the cost, including network upgrades, to interconnect each individual facility with the ISO-NE grid (DOER Brief at 18, citing Exh. DOER-1-6). DOER argues that a fair reading of the RFP does not provide for an analysis of potential incremental transmission upgrades necessary as a result of a bundle of selected projects when considered collectively (DOER Brief at 19; DOER Reply Brief at 3, 5, citing Tr. at at 139-141).

DOER notes that the language in Section 2.4 of the RFP concerning transmission costs was added in response to the possibility that a project developer could propose to recover transmission costs outside of the PPAs. The Distribution Companies received no such bids in response to the instant RFP (DOER Brief at 19, citing Exh. DPU-4-16; Tr. at 140). DOER also argues that an analysis of potential future transmission upgrades and how those costs would be allocated to Massachusetts ratepayers is not feasible in this context and is within the purview of ISO-NE (DOER Brief at 19, citing Tr. at 141, 193-194; DOER Reply Brief at 5-6). DOER further notes that current ISO-NE planning studies do not show that short-term or mid-term transmission upgrades are needed in areas where the selected projects are located, and argues that the Attorney General's witnesses failed to consider recent studies in their analysis (DOER Brief at 19-21; DOER Reply Brief at 6-7).

In response to the Attorney General's argument that consideration of indirect transmission costs from the bundle of projects is required under the RFP, DOER argues that the Attorney General should have raised this issue as part of Departmental review of the RFP in D.P.U. 13-57, rather than in the current proceedings (DOER Reply Brief at 2-3). DOER states that the Attorney General raised issues in her comments on the RFP related to fair comparison between bids that include transmission costs and those that seek recovery through a FERC-approved tariff in D.P.U. 13-57, but did not raise any issue or concern regarding the consideration of transmission impacts where there was no proposal to include such costs in a bid (DOER Reply Brief at 3).

3. First Wind

First Wind contends that the Distribution Companies correctly followed the Department-approved RFP (First Wind Brief at 4-5; First Wind Reply Brief at 2). First Wind states that any cost of the potential transmission upgrades required to interconnect the bundle of projects is likely unknowable at this time, and that there is no meaningful way for the Distribution Companies to evaluate such costs (First Wind Brief at 5; First Wind Reply Brief at 3). First Wind also contends that the sellers in the instant PPAs are responsible for transmission upgrades necessary to interconnect a specific project to the ISO-NE grid (First Wind Brief at 6, citing Exh. DPU-4-17; First Wind Reply Brief at 2). First Wind argues that such costs are the only knowable transmission upgrades required to interconnect a project to the grid and that the Distribution Companies properly considered them in their review of the bids (First Wind Brief at 6). First Wind also argues that nothing in the joint RFP would require the Distribution Companies to consider incremental transmission investment as part of their bid evaluation (First Wind Reply Brief at 2-3).

In addition, First Wind contends that the transmission issues raised by the Attorney General in D.P.U. 13-57 are related to bids that seek to recover transmission costs through a FERC-approved tariff and are completely different from the potential incremental transmission costs from the bundle of projects raised in the instant proceedings (First Wind Reply Brief at 3, citing D.P.U. 13-57). First Wind argues that there is no suggestion in D.P.U. 13-57 that the Department would be willing to address the issue of whether the Distribution Companies should have considered a different bundle of projects based on potential future regional transmission upgrades (First Wind Reply Brief at 3).

4. Cape Light Compact

CLC contends that review of projects under a Section 83A solicitation is not the proper forum to conduct a project by project transmission analysis as suggested by the Attorney General (CLC Reply Brief at 2). CLC argues that the Attorney General’s suggested analysis incorrectly presumes that an identified need for reliability upgrades to the bulk transmission system can be directly attributed to an individual project or to a bundle of projects (CLC Reply Brief at 2, citing Exh. AG-JCJW-1). Thus, CLC states that any evaluation of projects that attempts to assign potential bulk transmission upgrades to a single project as if it were solely responsible for such transmission upgrade costs (i.e., such costs would not be incurred without such project) could unduly prejudice potentially valuable projects (CLC Reply Brief at 2).

5. Distribution Companies

The Distribution Companies contend that the collaborative joint solicitation process was fully consistent with the requirements of Section 83A (Distribution Companies Brief at 18). The Distribution Companies assert that their evaluation of bids may only properly apply criteria in the RFP, in order to satisfy the Department's precedent that competitive solicitations be fair, open, and transparent (Distribution Companies Reply Brief at 14, citing D.P.U. 11/05/11-06/11-07, at 40).

The Distribution Companies note that there are two types of transmission investments under consideration in the context of this proceeding: (1) costs necessary to interconnect a specific facility with the ISO-NE grid; and (2) costs associated with future incremental transmission upgrades that may be required to maintain reliability in the region (Distribution Companies Reply Brief at 3 n. 2, 5). The Distribution Companies argue that, as required in the RFP, the developers of the projects under consideration in this proceeding are wholly liable for the costs to transmit project output to the ISO-NE PTF because no bidders sought to recover transmission costs outside of the PPAs (Distribution Companies Reply Brief at 5-6, citing Exh. DPU-4-16). In addition, the Distribution Companies argue that the transmission costs necessary to transmit energy from a project to the Delivery Point are the only costs authorized for recovery under the PPAs, and therefore were the only transmission costs evaluated by the Distribution Companies in their review of the bids (Distribution Companies Reply Brief at 7, 9). Thus, the Distribution Companies contend that it is incorrect to suggest that they failed to properly evaluate the transmission costs that can be directly assigned to any of the three projects and state that the Attorney General has not made such a claim in these proceedings (Distribution Companies Reply Brief at 6-7).

The Distribution Companies contend that the Attorney General is addressing potential future transmission upgrades beyond the Delivery Point identified in each PPA (Distribution Companies Reply Brief at 7-8). The Distribution Companies state that analyzing these transmission costs in isolation as part of a competitive procurement would be unlikely to produce valid results and would be entirely speculative (Distribution Companies Reply Brief at 4-5, 7, 15, 18, citing Tr. at 193, 203-204, 213-214, 242). The Distribution Companies further state that the Attorney General's witnesses offer no guidance on how such an evaluation could occur, but instead offer only conceptual estimates, based on broad planning studies (Distribution Companies Reply Brief at 15-16). The Distribution Companies also argue that it would be difficult to ascribe any subsequent transmission upgrades to any single bid or bundle of proposals (Distribution Companies Reply Brief at 16-17). The Distribution Companies contend that if the Distribution Companies rejected the low-cost projects that are the subject of the PPAs, such projects likely will be built pursuant to a subsequent competitive solicitation conducted in another New England state (Distribution Companies Reply Brief at 17). Under such a scenario, the Distribution Companies argue that Massachusetts ratepayers would pay both potential future regional transmission costs and higher contract costs associated with higher-cost renewable generation (Distribution Companies Reply Brief at 17).

Finally, the Distribution Companies argue that charges for regional transmission upgrades are based on the load of each transmission customer under the ISO-NE tariff

(Distribution Companies Reply Brief at 9). The Distribution Companies maintain that since the energy purchased under the PPAs does not impact their distribution load, the customers of the Distribution Companies will incur no directly attributable additional transmission costs under each PPA past the Delivery Point (Distribution Companies Reply Brief at 9). Thus, the Distribution Companies argue that the Department should not require analysis of such costs in its review of this solicitation (Distribution Companies Reply Brief at 4-5).

The Distribution Companies argue that stage three of the evaluation process provides them discretion to re-rank projects according to specific additional factors, including cost effectiveness and portfolio effect (Distribution Companies Reply Brief at 10-11, citing Exh. JU-7(A) at 20). However, the Distribution Companies aver that considering the cost of regional transmission upgrades is not a proper consideration of bid cost-effectiveness because those costs are external to the PPAs and will not be recovered from ratepayers or the Distribution Companies through the PPA payments (Distribution Companies Reply Brief at 11-12). As such, the Distribution Companies argue that prospective transmission upgrades are not a consideration related to the cost effectiveness of the PPAs (Distribution Companies Reply Brief at 11-12).

The Distribution Companies also state that the consideration of "portfolio effect" is defined in the RFP as the "value of diversity of resources by size and type," and under a plain reading of the RFP, project "type" refers only to technology type, and not project location as argued by the Attorney General (Distribution Companies Reply Brief at 12, citing Tr. at 119-120). Thus, the Distribution Companies argue that they do not have the discretion to re-rank the bundle of selected projects based on project location or consideration of potential incremental transmission costs beyond the Delivery Point under the stage three evaluation criteria in the RFP (Distribution Companies Reply Brief at 8, 13-14). The Distribution Companies, therefore, assert that they did not omit any applicable evaluation criteria set forth in the RFP and urge the Department to reject the Attorney General's contention that the RFP provided the discretion to review projects on a bundled basis due to hypothetical transmission cost assumptions (Distribution Companies Reply Brief at 15).

D. Analysis and Findings

In evaluating the competitiveness of a procurement process, the Department considers whether the process was open, fair, and transparent. D.P.U. 11-05/11-06/11-07, at 40, citing D.P.U. 10-114, at 221; D.P.U. 07-64-A at 60-61 (noting the "Department's fundamental interest in open, competitive, and transparent procurement processes"); Boston Gas Company, Colonial Gas Company, and Essex Gas Company, each d/b/a KeySpan Energy Delivery New England, D.T.E. 04-9, at 10 (2004) (RFP is acceptable if the process was open, fair, and transparent), quoting Natural Gas Unbundling, D.T.E. 98-32-B at 54–55 (1999)). Further, with respect to the bid evaluation process, the Department considers whether bids were evaluated and winning bids were selected in a reasonable manner, based on the criteria set forth in the RFP. D.P.U. 11-05/11-06/11-07, at 40, citing D.T.E. 04-9, at 10; The Berkshire Gas Company, D.T.E. 02-56, at 10 (2002).

With regard to whether the solicitation was open, the Distribution Companies disseminated the statewide RFP to a broad group of potential bidders - over 300 entities in the renewable energy development industry received the RFP (Exh. JU (rev.) at 17, 22). In response to the RFP, the Distribution Companies received a considerable number of bids (i.e., 40 bids with 112 price offers) (Exh. JU (rev.) at 22). Accordingly, given the broad dissemination of the solicitation to potential bidders and the magnitude of the actual number of bids received the Department finds that the solicitation was open.

For the Department to find that the solicitation process was fair and transparent, the Distribution Companies must demonstrate that: (1) the evaluation process was clearly stated to each potential bidder; (2) the evaluation criteria were provided in the RFP; and (3) there was an opportunity for bidders to request clarification on both the evaluation criteria and the RFP process itself. D.P.U. 11-05/11-06/11-07, at 42, citing D.P.U. 10-114, at 221; D.P.U. 07-64-A at 60-61 n.21; D.T.E. 04-9, at 10.

The Department previously has determined that the timetable and method of solicitation used for the RFP process at issue in these proceedings are consistent with Section 83A and 220 C.M.R. § 21.00 et seq. D.P.U. 13-57, at 25-26. As discussed above, the Department-approved RFP specifically provided the criteria that the Distribution Companies were to use in each step of the bid evaluation process (Exh. JU-7(A) at 8-20). In addition to the guidelines provided in the RFP, the Distribution Companies provided potential bidders with the opportunity to submit questions on the RFP process electronically, via a website hosted by the Distribution Companies and DOER, and also held a pre-bid conference after the RFP was issued at which potential bidders could seek further clarification (Exh. JU (rev.) at 22). Accordingly, the Department finds that the Distribution Companies have demonstrated that they conducted a fair and transparent solicitation process.

The Distribution Companies, DOER, and First Wind argue that the bid evaluation process was consistent with the Department-approved RFP (Distribution Companies Reply Brief at 14; DOER Brief at 15; First Wind Brief at 4-5). The Attorney General argues that the Distribution

Companies' bid evaluation process was broadly consistent with the terms of the RFP, with one exception, i.e., the Distribution Companies' failure to adequately consider the costs of potential incremental transmission upgrades or expansions necessary to deliver or integrate the aggregate electricity produced by the selected projects to the ISO-NE grid (Attorney General Brief at 15, 19, citing Exh. AG-JCJW-1, at 7, 23-30, 33-34; Tr. at 201-203).

The Department agrees with the Distribution Companies and others that the bid evaluation process was consistent with the Department-approved RFP. The Distribution Companies conducted a thorough analysis of the bids in stages one and two of the evaluation process (Exhs. JU-8 (Confidential); JU-9 (Confidential)). They then gave all of the highest scoring projects the opportunity to revise their bids in stage three, and re-ranked the bids accordingly (Exh. JU at 28, 30). This quantitative analysis was based on the criteria provided in the RFP (Exhs. JU-8 (Confidential); JU-10 (Confidential); JU-11 (Confidential)). The Distribution Companies used an updated method to determine the price scores of projects in order to improve on the method used in prior solicitations (Exhs. DPU-7-1; AG-JCJW-1, at 21).

As for the analysis of potential incremental transmission upgrade costs, we disagree with the Attorney General that the RFP requires the Distribution Companies to conduct such an analysis and decline to require the Distribution Companies to do so now. Under the terms of each of the PPAs, the seller is responsible for all costs necessary to interconnect its project to the ISO-NE PTF (Exhs. JU-1 (A) at 24-25; JU-1(B) at 24-25; JU-1(C) at 26; JU-1(D) at 24-25; JU-3(A) at 23; JU-3(B) at 23; JU-3(C) at 26; JU-3(D) at 23; JU-4 (A) at 23; JU-4(B) at 23; JU-4(C) at 25; JU-4(D) at 23). The plain language of the Department-approved RFP does not require the Distribution Companies to conduct an analysis of future regional transmission upgrades as part of the stage three evaluation or at any point in the evaluation process. All direct references to transmission costs in the description of the stage three evaluation requirements pertain to projects that seek to recover transmission costs through a FERC-approved tariff (Exh. JU-7(A) at 20). As we indicated earlier, no bidders sought that option (Exh. DPU-4-16).

Contrary to the assertion of the Attorney General, the "portfolio effects" the RFP refers to explicitly are "size and type" of projects without reference to location or any additional criteria including transmission costs (Exh. JU-7(A) at 20; Tr. at 117-121). In addition, the RFP allows the Distribution Companies to re-rank proposals at "their discretion" and "provides for a reasonable degree of considered judgment based on criteria specified in this RFP" (Exh. JU-7(A), at 20). However, the Distribution Companies are required and allowed to consider only the factors explicitly listed in the RFP during their stage three evaluation, none of which includes the type of analysis suggested by the Attorney General.[21] In addition, even if such an analysis were allowed under the terms of the RFP, we agree with the Distribution Companies, DOER, First Wind, and CLC that it would be impossible to know at this time what, if any, future regional transmission upgrades would be required to maintain system reliability, and how those costs would be allocated to Massachusetts ratepayers. Accordingly, conducting such an analysis is outside of the scope of a Section 83A cost-effectiveness analysis. Further, as noted by CLC and the Distribution Companies, it is not proper to allocate all potential future transmission upgrades identified by the ISO-NE to any one project, or bundle of projects.

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[21] The Department, therefore, declines to require the Distribution Companies to file the additional information the Attorney General has requested.

Transmission upgrades are made to maintain and upgrade regional reliability. Therefore, assigning all transmission upgrade costs to specific projects in response to a Section 83A RFP may prejudice otherwise eligible projects that may not be the sole reason for the installation of future transmission upgrades to maintain regional reliability.

Accordingly, for all of these reasons, we find that the Distribution Companies conducted a bid evaluation process that was reasonable and consistent with the criteria set forth in the RFP.

VI. COMPLIANCE WITH SECTION 83A

A. Introduction

Section 83A of the Green Communities Act and the Department's regulations at 220 C.M.R. § 21.00 et seq. require the Department to make specific determinations regarding a proposed long-term contract for renewable energy. As a threshold matter, the Department must determine that the proposed contracts facilitate the financing of renewable energy facilities. In addition, the Department must make determinations related to: (1) the facility's proposed commercial operation date; (2) the facility's qualification by DOER for the Massachusetts Class I RPS; (3) the facility's ability to provide enhanced electric reliability; (4) the facility's ability to moderate system peak load; (5) job creation and economic benefits; (6) the cost effectiveness of each contract as a mechanism for procuring renewable energy on a long-term basis;[22] and (7) apportionment among Distribution Companies. Section 83A; 220 C.M.R. § 21.05(1). Each of these requirements is discussed below.

[22] The Department also is required to make a determination that the contracts are cost effective over the life of the contracts. Section 83A; 220 C.M.R. § 21.05(c)(3). The Department addresses the bill impacts of the contracts in Section IX, below.

B. Facilitation of Financing

1. Introduction

Section 83A requires Distribution Companies to twice solicit long-term contracts to facilitate the financing of renewable energy generation. Section 83A; see also 220 C.M.R. § 21.01(1). Therefore, as a threshold issue, the Department must determine if the PPAs facilitate the financing of renewable energy projects. D.P.U. 11-05/11-06/11-07, at 14-15.

2. Positions of the Parties

The Distribution Companies assert that the joint competitive bid solicitation method used was developed to satisfy their obligation to enter into "cost-effective long-term contracts to facilitate the financing of renewable energy generation" (Distribution Companies Brief at 9). They argue that stages two and three of the RFP evaluation process include ranking each bid for both price and non-price factors, including an assessment of "each project's need for the PPA in order to facilitate its financing" (Distribution Companies Brief at 10-11, citing Exh. JU (rev.) at 26).

The Distribution Companies maintain that First Wind's bids explain that external financing of both the Oakfield Wind and Bingham Wind projects were dependent upon the long-term revenue commitment made possible through a PPA (Distribution Companies Brief at 18, citing Exh. JU (rev.) at 41). In addition, First Wind asserts that approval of the Evergreen Wind and Blue Sky West PPAs will facilitate the financing of the Oakfield Wind and Bingham Wind facilities (First Wind Brief at 4, citing Exh. JU (rev.) at 41). The Distribution Companies further maintain that each year Iberdrola considers and pursues a number of proposed renewable energy projects, but that it relies on executed PPAs to identify and advance projects to maturity and construction (Distribution Companies Brief at 18, citing Exh. JU (rev.) at 41). Thus, the Distribution Companies conclude that the resulting PPAs will facilitate the financing of renewable energy generation in the region (Distribution Companies Brief at 18).

3. Analysis and Findings

Section 83A requires, as a threshold matter, that an electric distribution company demonstrate that any proposed long-term contract will facilitate the financing of a renewable energy project. To satisfy this requirement, an electric distribution company need not demonstrate that the long-term contract is necessary to secure project financing, only that it will assist in securing project financing. D.P.U. 12-30, at 40; D.P.U. 10-54, at 52.

The Distribution Companies argue that, based upon the information provided by bids in the RFP process, the PPAs would support the ability to finance the projects (Distribution Companies Brief at 9). In their bids, First Wind indicated that external financing is dependent upon long-term revenue commitments, and Iberdrola indicated that it relies upon PPAs to advance projects to the construction phase of development (Exhs. JU (rev.) at 41; Workpapers Support at Tab C (Confidential)).

Previously, we have found that entering a long-term contract with a creditworthy counterparty, such as a distribution company, allows a developer to obtain more favorable financing and avoid the volatile short-term financing market. D.P.U. 11-05/11-06/11-07, at 18-19. No party has presented evidence that would cause us to change our conclusion. Thus, the Department finds that the proposed contracts with Evergreen Wind, Blue Sky West and Iberdrola will facilitate the financing of the Oakfield Wind, Bingham Wind and Wild Meadows Wind projects, respectively.

C. Commercial Operation Date and RPS Qualification

Pursuant to Section 83A and 220 C.M.R. § 21.05(1), the Department must make two threshold determinations regarding the facilities. To be an eligible renewable energy generating source, each facility must: (1) have a commercial operation date, as verified by DOER, of January 1, 2013 or later; and (2) be qualified by DOER as eligible to participate in the RPS program and sell RECs under the program, pursuant to G.L. c. 25A, § 11F.

None of the subject wind facilities is currently in operation and each has a prospective commercial operation date: Oakfield Wind in 2015, and Wild Meadows Wind and Bingham Wind in 2016 (see Exh. JU (rev.) at 34). Therefore, the Department finds that the facilities will have commercial operation dates of January 1, 2013 or later as required by Section 83A and 220 C.M.R. § 21.05 (1) (Exh. JU (rev.) at 35-36).

Although the project developers do not yet have DOER approval for Class I RPS qualification, as wind generation facilities located in the ISO-NE region Wild Meadows Wind, Oakfield Wind, and Bingham Wind are each eligible for qualification as Class I RPS sources pursuant to 225 C.M.R. § 14.05 (1)(a) (Exh. JU at 35). In addition, the proposed contracts provide that the Distribution Companies are not obligated to purchase RECs if the facilities fail to qualify for Class I RPS (Exh. JU at 35). Therefore, prior to the delivery of any products under the contracts, the Department finds that the facilities will meet the Class I RPS eligibility requirements of Section 83A and 220 C.M.R. § 21.05 (1).

D. Enhanced Reliability

1. Introduction

Pursuant to Section 83A, the Department must determine that the renewable energy generating resources will "provide enhanced electricity reliability within the [C]ommonwealth." See also 220 C.M.R. § 21.05 (1)(c)(1). While Section 83A does not define reliability, the Northeast Power Coordinating Council ("NPCC") and North American Electric Reliability Council ("NERC") define reliability as the ability to contribute to system resource adequacy and system security. D.P.U. 10-54, at 181.

2. Positions of the Parties

The Distribution Companies maintain that because each of the facilities will connect to an ISO-NE transmission node, the output of each facility will add to base supply in the region and also will increase supply reserve margins, thus contributing to system reliability (Distribution Companies Brief at 15, citing Exh. JU (rev.) at 35). First Wind maintains that the Evergreen Wind and Blue Sky West PPAs will increase supply reserve margins and fuel diversity, thereby enhancing reliability in Massachusetts (First Wind Brief at 3, citing Exh. JU (rev.) at 35).

3. Analysis and Findings

The Wild Meadows Wind project will interconnect to an ISO-NE PTF in New Hampshire, while the Oakfield Wind and Bingham Wind projects will interconnect to the ISO-NE PTF in Maine (Exh. JU at 35). Given that Massachusetts is part of ISO-NE, a regional electric system, an improvement in reliability in one area of the system will help to bolster the reliability of the system as a whole. In addition, as wind facilities, the facilities will contribute to fuel diversity in the region, thereby increasing reliability. Accordingly, the Department finds that the Wild Meadows

Wind, Oakfield Wind, and Bingham Wind projects will enhance reliability in the region and in Massachusetts.

E. Moderation of System Peak Load Requirements

1. Introduction

Pursuant to Section 83A and 220 C.M.R. § 21.05 (1)(c)(2), the Department must determine that the renewable energy generating resources that are the subject of long-term contracts will contribute to the moderation of system peak load requirements. The Distribution Companies submitted documentation of the estimated capacity factor during on-peak periods for each year for each of the wind facilities (Exhs. DPU-4-21; DPU-4-20 (Confidential)).

2. Positions of the Parties

The Distribution Companies assert that the wind projects will be price takers and as such that their output will be located at the bottom of the ISO-NE bid stack (Distribution Companies Brief at 15).[23] According to the Distribution Companies, this will make theirs the first generation to be dispatched in ISO-NE, thereby reducing the amount of load to be met by remaining generation sources (Distribution Companies Brief at 15). First Wind also asserts that the Evergreen Wind and Blue Sky West PPAs will reduce the amount of load that must be met by the region's remaining generation resources (First Wind Brief at 3, citing Exh. JU (rev.) at 35). No other party commented on moderation of system peak load requirements.

[23] Wind generators have no fuel cost, and thus are expected to bid into the ISO-NE wholesale energy market at a price near zero. As a result, they are expected to reduce overall regional wholesale electricity prices. See, e.g., D.P.U. 12-30, at 71.

3. Analysis and Findings

To determine whether a renewable energy resource will moderate system peak load requirements, the Department considers a facility's output and capacity factor at the electric system's peak. D.P.U. 10-54, at 198. Based on our review of each facility's generation characteristics and in consideration of the capacity value of land-based wind during both summer and winter periods, we find that the facilities are likely to produce power during peak times and will, therefore, contribute to moderating system peak load requirements (Exhs. DPU-4-21; DPU-4-20 (Confidential)). In addition, because wind facilities have zero fuel costs and are thus price takers, wind facilities will be placed toward the bottom of the bid stack for ISO-NE dispatch, thereby reducing the amount of load placed upon the remaining generation units (Exh. JU (rev.) at 35).

F. Employment Benefits and Economic Development

1. Introduction

Pursuant to Section 83A, the Department must determine whether the renewable energy resource under a long-term contract will create additional employment and economic development, where feasible. See also 220 C.M.R. § 21.05 (1)(c)(4).

2. Positions of the Parties

The Distribution Companies state that the facilities will create additional employment during the initial construction phase as well as during long-term plant operations (Distribution Companies Brief at 15). According to the Distribution Companies, Iberdrola estimates that the construction phase of the Wild Meadows Wind project will create 125 jobs, while commercial plant operations will require five to six permanent positions (Distribution Companies Brief at 15, citing Exh. JU (rev.) at 42). First Wind estimates that its Oakfield Wind project will generate 223 construction-phase positions and six to ten permanent jobs while Bingham Wind will generate 215 construction-phase jobs and ten to 15 on-going positions (First Wind Brief at 4, citing Exhs. JU (rev.) at 42; DPU-4-25).

The Distribution Companies also contend that the facilities will result in millions of dollars for local economies (Distribution Companies Brief at 15-16). According to the Distribution Companies, Iberdrola estimates that Wild Meadows Wind will create economic benefits from payment in lieu of taxes agreements, land use change payments, state utility property tax payments and annual payments to landowners (Distribution Companies Brief at 15-16, citing Exh. DPU-4-25). First Wind also estimates that its Oakfield Wind and Bingham Wind projects will produce economic benefits in the form of community benefit agreements, annual property tax revenue, and supply chain opportunities for New England business (First Wind Brief at 3-4, citing Exh. DPU-4-25). No other party commented on employment benefits or economic development.

3. Analysis and Findings

The Department recognizes that estimates of employment potential for each facility may contain uncertainties and that actual benefits could be different from projections. Nevertheless, there is no dispute that the construction and operational phases for each of the facilities will result in additional employment (Exh. JU (rev.) at 42).

The Department also is aware that, as with additional employment, approximations for financial benefits to the economy are only estimates. However, the creation of these facilities and their long-term operation will undoubtedly result in economic benefit for the region

(Exh. DPU-4-25). Accordingly, the Department finds that the Wild Meadows Wind, Oakfield Wind, and Bingham Wind facilities will create additional employment and benefits to the regional economy.

G. Apportionment among Distribution Companies

Section 83A of the Green Communities Act requires the Distribution Companies to jointly solicit proposals from renewable energy developers and enter into cost-effective long-term contracts for the Distribution Companies' apportioned share of the output from the selected projects. Section 83A provides that each apportioned share shall be based upon the total energy demand from all distribution customers in each service territory of the Distribution Companies. The Distribution Companies have calculated their respective pro rata shares as follows: National Grid – 45.9 percent; NSTAR – 45.4 percent; WMECo-7.7 percent; and Fitchburg-1.0 percent (Exh. JU (rev.) at 14 n. 2). These percentages have been memorialized in the PPAs as the "Buyer's Percentage Entitlement" (Exhs. JU-1(A), JU-1 (B), JU-1(C), JU-1(D); JU-3(A), JU-3(B), JU-3 (C), JU-3(D); JU-4(A), JU-4(B), JU-4(C), JU-4(D)). The three wind projects are expected to produce a total of 1,176,717 MWh per year of renewable energy and RECs, or approximately 2.5 percent of each Distribution Company's load (Exh. DPU-4-18 (supp.)).[24] Therefore, the Department finds that as required by Section 83A each of the Distribution Companies is purchasing its required pro rata share of the output of the renewable energy facilities.

[24] Each Distribution Company will purchase approximately 2.5 percent of its load from each of the three projects (i.e., National Grid will purchase 539,904,384 kWh; NSTAR will purchase 533,923,668 kWh; Fitchburg will purchase 11,906,892 kWh; and WMECo will purchase 90,982,281 kWh) (Exh. DPU-4-18 (supp.)).

H. Cost Effectiveness

Section 83A requires the Department to consider both the potential costs and benefits of the PPAs and provides that the Department shall approve a contract only upon finding that it is a cost-effective mechanism for procuring low-cost renewable energy on a long-term basis taking into account the factors outlined in Section 83A. See also 220 C.M.R. § 21.00 et seq.

In D.P.U. 10-54, the Department first considered the appropriate standard for evaluating the cost effectiveness of a long-term contract for renewable energy under Section 83 and determined that it would:

> consider in our cost-effectiveness analysis all costs and benefits associated with [a proposed contract], including the non-price benefits that are difficult to quantify, and including costs and benefits of complying with existing and reasonably anticipated future federal and state environmental requirements… . In reviewing [the] benefits and costs of [a proposed contract]… our focus is on the benefits and costs that accrue to [the distribution company proposing the contract] and its customers.

D.P.U. 10-54, at 71.

Accordingly, the Department will evaluate the cost effectiveness of each PPA based on the costs and benefits of each PPA to the Distribution Companies' ratepayers. We will first examine the difference between the contract costs and market value of the products. In addition, we will consider whether additional, unquantified benefits will accrue to the Distribution Companies' ratepayers over the term of each proposed PPA. Finally, the Department must consider whether the proposed contracts are a cost-effective method for obtaining low-cost renewable energy on a long term basis. Section 83A.

1. Contract Net-Benefits

a. Introduction

As a first step in evaluating the cost effectiveness of a proposed contract, the Department must determine the contract's quantified net benefits, or the difference between the costs of the contract and the market value associated with the products purchased pursuant to the contract (i.e., energy and/or RECs). D.P.U. 11-05/11-06/11-07, at 28, citing D.P.U. 10-54, at 79. The projected market value of the products, over the life of the PPAs, is determined by multiplying the estimated production of each facility by the estimated per unit market price of the products, based on a forecast of market prices (Exh. JU at 38-39). See also D.P.U. 10-54, at 90. The Distribution Companies estimated the value of the contract products by engaging a consultant to develop a forecast of market prices for energy and RECs ("Market Forecast") (Exhs. JU at 37; JU-12 (Confidential)).

Under the proposed PPAs, the wind projects will sell two products to the Distribution Companies: energy and RECs (Exh. JU (rev.) at 7). The Distribution Companies will sell the energy obtained under the PPAs in the ISO-NE wholesale electricity Day Ahead Energy Market or Real Time Energy Market ("Energy Market") and credit their distribution customers the revenues received (Exh. JU (rev.) at 43). NSTAR, National Grid, and Fitchburg propose to charge basic service customers for any RECs purchased under the PPAs and apply those RECs towards each company's RPS obligation associated with basic service[25] (Exh. JU (rev.) at 44).

[25] Pursuant to G.L. c. 25A, § 11F, all retail electric suppliers in the Commonwealth must procure a minimum percentage of their electricity sale from qualified renewable energy generating resources. As retail electric suppliers, the Distribution Companies are required to procure RECs on behalf of their basic service customers (Exh. JU (rev.) at 43-44). Pursuant to 220 C.M.R. § 21.05(c), the Distribution Companies can use RECs

NSTAR, National Grid and Fitchburg would then credit all distribution customers the same amounts charged to their basic service customers just as if RECs had been sold on the open market (Exh. JU (rev.) at 44). WMECo does not anticipate a need for RECs in connection with its RPS requirements and therefore proposes to sell the RECs obtained under the PPAs into the market and credit all distribution customers with the proceeds of such sale (Exh. JU (rev.) at 44).

The Distribution Companies' Market Forecast provides separate price projections for energy in each ISO-NE load zone (Exhs. JU (rev.) at 38; JU-12, at 2 (Confidential)). To develop its forecast of energy prices, the Market Forecast contains assumptions about various energy market factors, including: (1) demand for electricity; (2) New England generator additions and retirements; (3) costs of emissions allowances for air pollutants such as nitrogen oxide, sulfur oxide, and CO_2; (4) price of fuels such as natural gas; and (5) transmission upgrades (Exhs. AG-7-1; DPU-4-2; DPU- 4-3; DPU-4-5; DPU-4-7; DPU-4-8; DPU-4-9; DPU-4-11; DPU-4-12, DPU-4-13; JU-12, at 8 (Confidential)).

To develop its forecast of REC Energy Market prices in New England, the Market Forecast contains assumptions on drivers of REC supply and demand such as the region's renewable generation development queue, applicable RPS mandates, and a projection of load growth (Exhs. CLC 1-3; DOER 1-4; DPU 4-4; JU-12, at 31(Confidential)). In order to determine if the resulting projections of benefits are reasonable, the Department must evaluate whether the price forecast and the market revenue analysis are reliable. See D.P.U. 11-05/11-06/11-07, at 32; see also D.P.U. 10-54, at 108.

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purchased from these PPAs either for basic service RPS compliance or for sale on the market. In both instances, all distribution customers are credited the market value of those RECs (Exh. JU (rev.) at 43-44).

In order for the Department to determine whether the PPAs are cost effective over the life of the proposed contracts, the Department first looks at (a) the costs of the PPAs; and (b) the revenues to be received from selling the products in the markets. Pursuant to the proposed contracts, the Distribution Companies will purchase the energy and RECs associated with the output of the Wild Meadows Wind, Oakfield Wind and Bingham Wind facilities at prices that remain fixed over the terms of the contracts (Exhs. JU-1(A) at 55; JU-1(B) at 55; JU-1(C) at 20-21, 24-25; JU-1(D) at 18-19, 22-23; JU-3(A) at 17-18, 21-22; JU-3(B) at 17-18, 21-22; JU-3(C) at 19-20, 23-24; JU-3(D) at 17-18, 25-26; JU-4(A) at 17-18, 21-22; JU-4(B) at 17-18, 21-22; JU-4(C) at 19-20, 23-24; JU-4(D) at 17-18, 21-22; see also Exh. JU at 7).

Based on the forecasted market prices and estimated production of the facilities, the costs of all of the proposed contracts are projected to be below the market value of energy and RECs over the term of the contracts (Exh. JU (rev.) at 36-37, citing JU-12 at 40-43 (Confidential) and Workpaper Support, at Tab E (Confidential)). The Distribution Companies' analysis projects a net savings over the life of the PPAs of: (1) $171 million for the Wild Meadows Wind project, (2) $292 million for the Oakfield Wind project, and (3) $390 million for the Bingham Wind project, totaling $853 million, in nominal dollars, in net below-market costs[26] (Exh. JU (rev.) at 37, citing Workpaper Support, at Tab E (Confidential)).

[26] "Net below-market costs" refers to the comparison of a contract price for the products in each PPA (i.e., energy and RECs) to an estimated market price for such products. When purchasing a product, savings (or net benefits) are derived by subtracting the contracted price from the forecasted market price. See D.P.U. 11-05/11-06/11-07, at 28-29; D.P.U. 10-54, at 79.

b. Positions of the Parties

i. Attorney General

The Attorney General asserts that the Market Forecast is unreliable and, therefore, that the Department is not able to determine the cost effectiveness of the proposed PPAs (Attorney General Brief at 25). The Attorney General argues that the Market Forecast for energy assumes that certain new transmission lines will be built over the life of the contracts, but fails to account for the costs of such potential incremental transmission investment (Attorney General Brief at 25, citing Exh. AG-JCJW-1, at 8, 30-33; Tr. at 232-233). The Attorney General then argues that the Market Forecast's assumptions regarding transmission upgrades tend to result in overvaluing the energy that the two Maine renewable energy projects will produce and that the Distribution Companies likely over-estimated the benefits associated with the proposed contracts (Attorney General Brief at 15-19, 25-27, 29).

The Attorney General also questions the reasonableness of the Market Forecast's assumptions with respect to future REC prices (Attorney General Brief at 26, citing Exh. AG-JCJW-1, at 8, 30-33; Tr. at 232-233). Specifically, the Attorney General asserts that the use of REC price forecasts based on an estimation of REC supply and demand is problematic because open market values may not accurately reflect the costs that ratepayers would actually pay for RECs (Attorney General Brief at 26, citing Exh. AG-JCJW-1, at 30-33; Tr. at 232-233). The Attorney General maintains that these two issues call into question the Distribution Companies' forecast of the value of energy and RECs and that, therefore, the Market Forecast may not have yielded reasonable estimates about the cost effectiveness of the proposed PPAs (Attorney General Brief at 26).

Finally, the Attorney General argues that the Distribution Companies could not demonstrate that the selected bundle of projects is cost effective or least cost (Attorney General Brief at 18). Therefore, the Attorney General states that the Department should not approve the PPAs without first making findings as to what constitutes a reasonable estimation of benefits (Attorney General Brief at 30). Specifically, the Attorney General asserts that the Department should require the Distribution Companies to file additional information regarding transmission upgrades, future REC prices, and negative pricing (Attorney General Brief at 30).

ii. DOER

DOER argues that although the Attorney General's witnesses stated their preference for a "fundamental-type"[27] of REC market forecast, as compared to the forecast based on supply and demand of RECs presented by the Distribution Companies, the witnesses also concluded that each method is valid and appropriate (DOER Brief at 26, citing Tr. at 176-177, 229-232). DOER states that the fundamental-type REC price forecasts are less impacted by assumptions regarding the balance between supply and demand over long periods of time and are therefore preferred when assessing long-term contract proposals (DOER Brief at 26). DOER therefore recommends the use of a fundamental-type REC forecast, rather than a REC Energy Market forecast, in the next RFP (DOER Brief at 27).

In addition, DOER argues that the PPAs are likely to result in near-term and long-term savings to ratepayers, because pricing is below market currently and will remain so according to

[27] A "fundamental-type" REC forecast refers to a method of forecasting the value of RECs that uses an analysis of the expected revenue requirements of the marginal renewable generation unit minus the expected revenues for energy and capacity (DOER Brief at 26-27).

the forecast (DOER Brief at 16). DOER further notes that the PPAs could help reduce REC market prices overall by bringing RPS supply in balance with RPS demand, which should help reduce REC Energy Market prices to the benefit of all Massachusetts ratepayers (DOER Brief at 17).

iii. First Wind

First Wind argues that the cost of energy and RECs under the eight First Wind PPAs is significantly less than the forecasted market prices of energy and RECs during all years of the contracts and, therefore, that the PPAs for Evergreen and Blue Sky West are cost effective (First Wind Brief at 2-3, citing Exh. JU (rev.) at 35-41)

iv. Distribution Companies

The Distribution Companies assert that the proposed contracts are cost effective and below market (Distribution Companies Brief at 16-18). The Distribution Companies also assert that the Attorney General's arguments are not reasonable, and that the Market Forecast serves as a reliable benchmark to distinguish relative benefits of comparative bids (Distribution Companies Reply Brief at 19). The Distribution Companies argue that it is impractical and speculative to attempt to estimate the cost of incremental transmission upgrades to the PTF and then assign them to any particular projects because the costs of potential regional transmission upgrades are not incremental or avoidable with respect to any particular individual project (Distribution Companies Reply Brief at 19). The Distribution Companies further assert that consideration of incremental transmission upgrades to the PTF are not a consideration in a Section 83A proceeding and that without involvement of ISO-NE, such considerations are impractical and efforts would be "wholly conjectural and futile" (Distribution Companies Reply

Brief at 4-5). Accordingly, the Distribution Companies argue that the energy price forecast is a reasonable and reliable benchmark (Distribution Companies Reply Brief at 20).

With respect to the Attorney General's criticisms of their REC forecasting method, the Distribution Companies argue that the purpose of the forecast is to estimate an avoided cost of RECs, against which all REC bids can be compared (Distribution Companies Reply Brief at 19-20). The Distribution Companies assert that the accuracy of the forecast in comparison to actual REC prices is not as important as having a reasonable and consistent measure against which all bids can be compared (Distribution Companies Reply Brief at 20).

c. Analysis and Findings

In order to determine whether the Distribution Companies' projections of quantifiable net benefits are reasonable, the Department must evaluate whether the price forecast and market revenue analyses are reasonable. See D.P.U. 10-54, at 108. To do so, the Department must determine whether the forecast is a realistic projection of energy and REC prices. See D.P.U. 10-54, at 108.

The Distribution Companies used a robust and well established methodology to develop their Market Forecast of energy prices, including analysis of demand for electricity, generator additions and retirements, costs of emissions allowances for air pollutants, price of fuels such as natural gas, and reasonably assumed transmission upgrades (Exhs. JU-12, at 8 (Confidential); DPU-4-5; DPU-4-7; DPU-4-8; DPU-4-9).

To develop their projection of regional electricity prices for each hour between 2014 and 2038, the Distribution Companies' consultant simulated the New England regional energy market using an energy market production cost model (Exh. JU-12, at 7 (Confidential)).[28] As we have found previously, this type of analysis is valid for evaluating the benefits of energy from PPAs for renewable generation. D.P.U. 12-30, at 61.

Regarding the Attorney General's contention that the Market Forecast's assumptions regarding transmission upgrades are unreasonable, the Department notes that there are always uncertainties inherent in market price forecast assumptions. See, e.g., D.P.U. 10-54, at 105; D.P.U. 07-64-A at 67. The Market Forecast makes certain assumptions about the timing and location of regional transmission upgrades; however, the ability to assign the cost of specific incremental transmission upgrades to any specific project is speculative at best and potentially unknowable (Exhs. JU-12, at 29-31 (Confidential); DPU-4-9). In addition, the Attorney General's witnesses note that the Market Forecast's assumptions relative to future transmission upgrades are not unreasonable, but may overvalue the benefits of the PPAs (Exh. AG-JCJW-1, at 31-32). While we agree with the Attorney General that assumed costs related to transmission could overvalue the benefits of energy over the life of the proposed contracts, the same uncertainty could apply for all assumptions used in the Market Forecast. In fact, the Attorney General's witnesses conceded that the method the Distribution Companies used was adequate; moreover, the Attorney General's witnesses have not presented a reasonable alternative to the Market Forecast (see Tr. at 176-177, 229-232). Therefore, we find that the transmission assumptions contained in the Market Forecast are reasonable. Accordingly, we find that the

[28] An energy market production cost model simulates the security constrained economic dispatch of energy generation resources required to meet forecasted energy demand while minimizing the cost of reliably serving the expected load. See, e.g., D.P.U. 10-54, at 93. An energy market production cost model also will predict an hourly price of electricity at one or more specific locations. Id.

Market Forecast contains a realistic projection of energy prices and is, therefore, a reliable means for estimating the revenues associated with the energy to be sold pursuant to the proposed PPAs.

The Distribution Companies performed an analysis of the drivers of REC supply and demand in order to generate a REC Energy Market price projection in New England (Exhs. JU-12, at 31 (Confidential); DOER-1-4; Tr. at 176-179). The Attorney General and DOER each expressed a preference for the fundamental-type of REC market forecast used in Section 83 RFPs, rather than the Energy Market method used here (Attorney General Brief at 26; DOER Brief at 26-27). However, the Distribution Companies argue and the Attorney General's witnesses concede that the Energy Market method is also a valid approach (Tr. at 176-177, 229-232).

The Department has evaluated the major components of the REC forecast and found that the supply and demand curves are derived through well established methodologies and constitute a realistic projection of REC prices (see Exh. JU-12 (Confidential); Tr. at 176-179). The Department agrees that the Energy Market approach is one of numerous valid approaches to forecast REC prices (see Tr. at 176-179). In addition, the Distribution Companies applied the results of this approach in a consistent manner for all bids in the RFP (see Exh. JU-8 (Confidential)). Accordingly, the Department finds the Market Forecast is a reliable means for estimating the revenues associated with the RECS produced in the proposed PPAs. Based on this forecast, the proposed contracts are estimated to achieve a total of $853 million in net below-market costs.

The Attorney General argues that without further analysis of potential incremental transmission upgrade costs to interconnect the bundle of projects, the Distribution Companies are unable to show that the PPAs are cost effective (Attorney General Brief at 18). However, the Attorney General's witnesses do not go so far as to contend that the PPAs are not cost effective (see, e.g., Tr. at 202-204, 208-209). As discussed more fully in SectionV.D, above, the Department found that it is unreasonable to ascribe future incremental transmission upgrade costs to any particular facility outside of those costs necessary to interconnect that facility to the ISO-NE grid. The evaluation of an RFP is not the proper forum to assess these costs. The Department affirms that the Distribution Companies have demonstrated that the proposed contracts are below market and yield net benefits to ratepayers. Finally, we note that the Attorney General argues that the Department must find the proposed contracts to be a cost-effective mechanism for procuring least-cost renewable energy on a long-term basis (Attorney General Brief at 18). We further note that the Attorney General's position is a misreading of the plain language of Section 83A, which explicitly calls for a determination that the resource is low cost, not least cost.

The Department finds the Market Forecast uses robust and well established methodologies to develop its forecast of energy prices. Further, we find the consideration of transmission upgrades within the Market Forecast as timely, practical and adequate for the purposes of establishing a reliable forecast of energy prices. The Department also finds that the Market Forecast contains a realistic projection of REC prices, and is, therefore, reliable for estimating the revenues associated with the products sold in the proposed PPAs. Using the methods described above, the market value of net benefits over the life of each contract is: (1) $171 million for the Wild Meadows Wind project, (2) $292 million for the Oakfield Wind project, and (3) $390 million for the Bingham Wind project, totaling $853 million in net below-market costs (Exh. JU (rev.) at 37).

2. Additional Unquantified Benefits

a. Introduction

There are other benefits associated with the contracts that, while difficult to quantify, have the potential to represent significant benefits to Massachusetts ratepayers and, therefore, merit discussion. In addition to the benefits from the moderation of system peak load, enhanced reliability, and additional employment and economic benefits discussed above, these benefits include: (1) compliance with the Commonwealth's renewable energy and environmental requirements; (2) hedge and price certainty; and (3) shielding ratepayers from certain other risks (Exh. JU (rev.) at 40).

b. Compliance with Renewable Energy and Environmental Requirements

The proposed contracts offer benefits to the Distribution Companies and their ratepayers in meeting renewable energy and environmental requirements, including compliance with the RPS requirements of the GCA and with the Global Warming Solutions Act ("GWSA"), G. L. c. 21N (Exh. JU (rev.) at 40). With respect to the RPS, retail electricity suppliers are required to procure RECs for a minimum percentage of their electricity sales from qualified renewable energy generating sources on an annual basis. G.L. c. 25A, § 11F. A renewable energy generating source that seeks a long-term contract pursuant to Section 83A must be qualified by DOER as eligible to participate in the RPS program and to sell RECs under the program.[29] In 2015, the year that the first facility is expected to enter commercial operation, the RPS Class I requirement will be at ten percent of annual electric sales for every retail electricity supplier including the Distribution Companies and will increase one percent per year. G.L. c. 25A, § 11F(a); 225 C.M.R. § 14.07.

As facilities that will ultimately be qualified as Class I renewable energy sources, Oakfield Wind, Wild Meadows Wind, and Bingham Wind will assist the Distribution Companies and other electricity suppliers in complying with Massachusetts RPS requirements. The facilities also will provide significant amounts of renewable generation to help fill the anticipated gap between the supply of and demand for renewable energy in New England (Exh. JU (rev.) at 35).[30] See also D.P.U. 10-54, at 161-162; D.P.U. 12-30, at 91-92. We find, therefore, that the ability of the Oakfield Wind, Wild Meadows Wind, and Bingham Wind facilities to help meet the Commonwealth's RPS requirements is a significant, yet unquantified, benefit of the proposed contracts. See D.P.U. 10-54, at 162-163 (finding that a project's ability to contribute to a

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29 As discussed above, none of the facilities at issue in these proceedings has yet received a Statement of Qualification from DOER as a Class I renewable energy source; however, as explained in Section VI. C above, wind-powered generation is eligible as a Class I source and the contracts require that the products delivered meet Class I RPS requirements (Exhs. JU (rev.) at 40; JU-1 (A) at 21, 23; JU-1 (B) at 21, 23; JU-1 (C) at 22-25; JU-1 (D) at 21, 23; JU-3 (A) at 19, 21; JU-3 (B) at 19, 21; JU-3 (C) at 22, 24; JU-3 (D) at 19, 21; JU-4 (A) at 19, 21; JU-4 (B) at 19, 21; JU-4 (C) at 21, 23; JU-4 (D) at 19, 21).

30 Massachusetts is part of a regional RPS market that includes all other New England states (except Vermont), each with its own RPS requirements. D.P.U. 10-54, at 140. Because Massachusetts Class I RECs may be used to meet the other New England states' RPS requirements, the supply and demand for renewable energy are influenced by the combined RPS requirements of the region. D.P.U. 10-54, at 140.

company's RPS requirements is consistent with the Green Communities Act as a whole and should therefore be considered a benefit of a PPA).

The GWSA, G.L. c. 21N, establishes a number of requirements for reducing greenhouse gas ("GHG") emissions in the Commonwealth.[31] Pursuant to the GWSA, Massachusetts must: (1) reduce its GHG emissions by ten to 25 percent of 1990 levels by 2020; (2) reduce its GHG emissions by at least 80 percent of 1990 levels by 2050; and (3) develop interim 2030 and 2040 emissions limits, to "maximize the ability of the [C]ommonwealth to meet the 2050 emissions limit." G.L. c. 21N, §§ 3(b), 4(a).

The GWSA does not specify policies for achieving the GHG emissions reduction requirements. Rather, it broadly empowers the Executive Office of Energy and Environmental Affairs ("EOEEA") and Department of Environmental Protection ("DEP"), in consultation with DOER, to conduct analyses and implement policies in order to realize the requirements. G.L. c. 21N, §§ 1-7; D.P.U. 12-30, at 93-94, 100. On December 29, 2010, pursuant to G.L. c. 21N § 4(a), the Secretary of EOEEA established a legally binding requirement that the Commonwealth reduce its GHG emissions by 25 percent of 1990 levels by 2020.[32] In addition, EOEEA published the Massachusetts Clean Energy and Climate Plan for 2020 ("2020 Climate

31 The GWSA defines GHG as, "any chemical or physical substance that is emitted into the air and that the [D]epartment [of Environmental Protection ("DEP")] may reasonably anticipate will cause or contribute to climate change including, but not limited to, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride." G.L. c. 21N, § 1.

32 Determination of Greenhouse Gas Emission Limit for 2020 (Mass. Executive Office of Energy and Envtl. Affairs) (December 29, 2012), available at http://www.mass.gov/eea/docs/eea/energy/2020-ghg-limit-dec29-2010.pdf.

Plan"),[33] which describes a portfolio of policies aimed at enabling the Commonwealth to achieve the 2020 emissions reduction requirement.[34] Recently EOEEA released a Global Warming Solutions Act Five-Year Progress Report ("GWSA Progress Report"),[35] which updated implementation of the 2020 Climate Plan and recommends areas to focus on for reducing GHG emissions over the next five years.

The 2020 Climate Plan contains estimates of the level of emission reductions to be achieved, grouped by various categories of emitting sources. 2020 Climate Plan at ES-5. The 2020 Climate Plan attributes the majority of emission reductions to the electric sector. 2020 Climate Plan at 14-48. Emission reductions from the electric supply sector are estimated to reduce statewide GHG emissions by 7.7 percent by 2020.[36] 2020 Climate Plan at ES-6. In addition, the 2020 Climate Plan projects a 9.8 percent reduction in GHG emissions from the buildings sector, which largely involves reducing emissions from electric end uses. 2020 Climate Plan at ES-6. Combining emissions reductions from electric supply and reduced electricity end uses, the 2020 Climate Plan projects that policies related to the electric sector will

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33 The 2020 Climate Plan is not part of the evidentiary records in these proceedings, however, the Department takes official notice of same. See 220 C.M.R. § 1.10(2).

34 Ian A. Bowles, Executive Office of Energy and Environmental Affairs, Massachusetts Clean Energy and Climate Plan for 2020 (December 29, 2010), available at http://www.mass.gov/eea/docs/eea/energy/2020-clean-energy-plan.pdf.

35 Executive Office of Energy and Environmental Affairs, Massachusetts Global Warming Solutions Act 5 Year Progress Report (December 30, 2013), available at http://www.mass.gov/eea/docs/eea/gwsa/ma-gwsa-5yr-progress-report-1-6-14.pdf.

36 The policies described in the 2020 Climate Plan include full implementation of the RPS, which is projected to reduce statewide emissions by 1.2 percent in 2020. 2020 Climate Plan at 40.

reduce statewide emissions by over 17 percent from 1990 levels by 2020. 2020 Climate Plan at ES-6. The GWSA Progress Report calls for continued implementation of GHG emission reduction policies in the electric sector, including expansion of clean energy resources and energy efficiency in order to reach the Commonwealth's 2020 and 2050 GHG emission reduction targets. GWSA Progress Report at 9-13.

The 2020 Climate Plan also describes two long-term scenarios under which the Commonwealth could meet the 2050 emissions reduction requirement. 2020 Climate Plan at 95-103. Both scenarios require significant expansions in renewable energy generation (i.e., increases of five to ten times the amount of near-zero greenhouse gas emissions energy consumed in Massachusetts in 2007). 2020 Climate Plan at 102.

Wind generation will be selected for dispatch as base load units, and thereby displace generation from fossil fuel facilities which are generally the marginal unit in New England (Exh. JU at 41). Wind generation is a renewable, near-zero carbon energy source. 2020 Climate Plan at 99. Together, the wind facilities that are the subject of these proceedings are expected to reduce greenhouse gas emission by 6.7 million tons over the term of the PPAs (Exh. JU (rev.) at 39-40). The contracts will, therefore, contribute to achieving a portion of the emissions reductions necessary to comply with the GWSA targets for the duration of the contracts. For these reasons, we conclude that the contracts will provide an unquantified, but significant, benefit to Massachusetts ratepayers and the Commonwealth by contributing to compliance with renewable energy and environmental requirements.

c. Hedge and Price Stability and Shielding Ratepayers from other Financial Risk

The fixed price nature of the contracts provides a benefit in the form of price stability. Massachusetts ratepayers will benefit from the ability of the contracts to provide price stability and act as a hedge against price increases and volatility. See D.P.U. 07-64-A at 66 (finding that inclusion of fixed prices in a long-term contract as an adjustment to basic service rates that otherwise will reflect general energy market volatility provides an appropriate element of basic service rate stability). In addition, the Department has found that fixed-price long-term contracts provide a hedge against both increasing electricity prices and increasing REC prices. D.P.U. 10-54, at 138; D.P.U. 07-64-A at 56, 66, 71. The value of such a hedge is based on the possibility that future market prices will exceed the cost of the fixed-price contract. See D.P.U. 10-54, at 138. In the instant dockets, the proposed contracts are expected to be below market value for the duration of the contracts (Exh. JU at 38). As such, the hedge value of the contracts would likely be significant

Other than the prices set in the contracts, there are no additional costs to Massachusetts ratepayers as a result of changes in the costs of the projects. Specifically, the Distribution Companies' customers do not bear any financial risk related to: (1) whether the facilities are eligible for tax credits; or (2) variability associated with the output of the facilities (Exh. JU (rev.) at 40). The contracts also provide that the project developers are solely responsible for obtaining and maintaining qualification to participate in the RPS program and that the products delivered under the contracts meet Class I RPS requirements (Exh. JU (rev.) at 40). Although the value of the benefits was not quantified in these proceedings, we conclude that price stability and the ability of the contracts to act as a hedge against future price increases and volatility are a benefit to Massachusetts ratepayers.

3. Conclusions Regarding Cost Effectiveness

Based on all of the considerations above, the Department finds that there are significant net benefits to Massachusetts ratepayers associated with the proposed long-term renewable energy contracts, i.e., the benefits are expected to far exceed the costs of the contracts. The market revenues from the contracts are expected to exceed the costs of the contracts by approximately: (1) $171 million for the Wild Meadows Wind project; (2) $292 million for the Oakfield Wind project; and (3) $390 million for the Bingham Wind project, totaling $853 million (Exh. JU (rev.) at 37).

In addition, there are significant unquantified benefits to Massachusetts ratepayers associated with the contributions of the contracts to: (1) enhanced reliability; (2) moderation of system peak load; (3) creation of employment and economic development; (4) compliance with renewable energy and environmental requirements such as the RPS and GWSA; and (5) hedge and price stability and shielding ratepayers from other financial risks.

Accordingly we find that the PPAs are cost-effective mechanisms for procuring low-cost renewable energy on a long-term basis, and that the contracts will be cost effective to Massachusetts ratepayers over their terms.

I. Conclusion Regarding Compliance with Section 83A

As discussed in greater detail above, the Department finds that the PPAs comply with the requirements of Section 83A. Specifically, the Department has found that the proposed contracts facilitate the financing of renewable energy facilities and are cost-effective mechanisms for the procurement of low-cost renewable energy. In addition, the Department has found that the PPAs comply with Section 83A's requirements regarding each facility's proposed commercial operation date, each facility's ability to moderate system peak load, and each facility's qualification by DOER to participate in the RPS program.

VII. PUBLIC INTEREST

A. Introduction

In Section VI.H above, the Department found that the proposed contracts will be cost effective to ratepayers over their terms; however, such a finding does not necessarily mean that procuring the proposed contracts is in the best interest of ratepayers and, therefore, in the public interest. See, e.g., D.P.U. 12-98, at 24; D.P.U. 11-05/11-06/11-07, at 39, citing D.P.U. 10-54, at 65. The Department's review of the public interest impacts of long-term contracts for renewable energy is based on the specific issues that are relevant to each proposed contract. See, D.P.U. 12-98, at 24; D.P.U. 11-05/11-06/11-07, at 39; D.P.U. 10-54, at 65-66. Here, as part of our evaluation of whether the contracts are in the public interest, the Department considers whether the pricing terms in the contracts are low cost and reasonable, given the type of renewable resource being purchased. See D.P.U. 12-98, at 25; D.P.U. 11-05/11-06/11-07, at 39; D.P.U. 10-54, at 217. The Department also considers whether other lower cost, Section 83A-eligible resources were available to the Distribution Companies and, if so, whether the benefits of the proposed contracts justify any higher costs. See D.P.U. 11-05/11-06/11-07, at 39; D.P.U. 10-54, at 217. In addition, because the proposed contracts are for more than the originally sought 1.8 percent of distribution load, the Department will consider whether the PPAs' size (i.e., contract amount) is reasonable. Finally, the Department considers whether the bill impacts of the contracts on customers are acceptable in light of the benefits of the contracts. See, e.g., D.P.U. 12-98, at 25; D.P.U. 11-05/11-06/11-07, at 39; D.P.U. 10-54, at 214.

B. Reasonableness of Price and Comparison to other Section 83A Eligible Resources

The Distribution Companies procured the contracts using a competitive solicitation process (Exh. JU (rev.) at 35-36). A properly conducted competitive procurement process provides a direct comparison of the costs and benefits of alternative resources, as well as some assurance that what the bidders are charging is not too high for a given resource. See D.P.U. 12-98, at 25, citing D.P.U. 11-05/11-06/11-07, at 39, citing D.P.U. 10-54, at 66-67. A competitive bidding and qualification process also provides an objective benchmark for analyzing the reasonableness of price. See New England Gas Company, D.P.U. 10-114, at 221 (2011), citing Bay State Gas Company, D.P.U. 09-30, at 228-229 (2009); Fitchburg Gas and Electric Light Company, d/b/a Unitil, D.P.U. 07-71, at 101 (2008); Boston Gas Company, d/b/a KeySpan Energy Delivery New England, D.T.E. 03-40, at 152 (2003). As discussed in Section V above, the Department found that the Distribution Companies conducted a fair, open and transparent solicitation process that was consistent with the Department-approved RFP process.

Through their use of a competitive solicitation process, we find that the Distribution Companies have adequately compared the costs and benefits of the selected projects to alternative Section 83A-eligible resources. Based on the factors discussed in Section V above, the Department finds that (1) there were no other Section 83A-eligible resources available to the

Distribution Companies that scored higher on price and combined price and non-price factors; and (2) the pricing terms are low cost and reasonable (Exh. JU-11, at 1 (Confidential)).[37]

C. Evaluation of Contract Size

1. Introduction

In order to determine whether a contract is in the public interest, the Department must also assess the reasonableness of the Distribution Companies' decision to enter into a contract of a given size. See D.P.U. 12-30, at 167; D.P.U. 10-54, at 265. Section 83A obligates the Distribution Companies to jointly solicit proposals twice for renewable energy between January 1, 2013 and December 31, 2016 equal to a total of four percent of the Distribution Companies' load. Section 83A also requires that ten percent of this total load requirement qualify as "newly developed, small, emerging, or diverse renewable energy" as determined by DOER. [38]

The Distribution Companies originally intended to contract for 1.8 percent of their distribution load but entered into agreements for a total of 3.5 percent of combined load because of additional highly scored projects and the uncertainty of the federal production tax credits beyond December 31, 2013 (Exh. JU (rev.) at 31-32). As a result of the termination of the

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37 As discussed in Section V above, the Attorney General argues that projects located in areas not requiring incremental transmission upgrades or expansions to integrate wind facilities may have been prejudiced during the bid evaluation process because the Distribution Companies did not adequately consider the potential benefit of avoided transmission costs (Attorney General Brief at 24). However, the Department has rejected this argument. See Section V(D).

38 These renewable energy projects: (1) must have a nameplate capacity smaller or equal to six MW, (2) cannot qualify as a Class I, II, or III net metering facility, and (3) must be a technology that did not have more than 30 MW installed in Massachusetts prior to April 1, 2012. Section 83A.

Fletcher Mountain, Passamaquoddy Wind, and Peskotmuhkati Wind projects, the Distribution Companies entered into PPAs for approximately 2.5 percent of the Companies' distribution load (based on 2011 figures), which equates to an obligation for the Distribution Companies to purchase up to a maximum of 409.5 MW of output from the wind facilities (Exhs. JU (rev.) at 7-8; JU-11, at 1; DPU-4-18 (supp.); Tr. at 153). Accordingly, we must determine whether the Companies' purchase of up to 409.5 MW of output from the wind projects is reasonable. The Attorney General, First Wind, CLC, and the Distribution Companies did not address contract size in their briefs.

2. Position of DOER

DOER contends that contracting for more than 1.8 percent of the Distribution Companies' load (i.e., the initial procurement target) is likely to benefit ratepayers because the wind projects are low-cost resources (DOER Brief at 16). DOER notes that a major benefit of the projects selected is that they should be able to take advantage of the Federal Production Tax Credit ("PTC") and Investment Tax Credit ("ITC") that expired at the end of 2013 (DOER Brief at 16). According to DOER, in 2013 the PTC had a value of $23/MWh, adjusted annually for inflation, and would apply to qualifying wind projects for their first ten years of operation (DOER Brief at 16).

In addition, DOER argues that the RECs purchased under the PPAs would help the Commonwealth in achieving its renewable energy objectives and could help reduce REC market prices overall (DOER Brief at 17). DOER states that signing PPAs that would produce more RECs than the Distribution Companies' original target of 1.8 percent could help bring RPS supply in balance with RPS demand and thereby should reduce REC Energy Market prices to the benefit of ratepayers (DOER Brief at 17).

3. Analysis and Findings

In considering whether the Distribution Companies' purchase of approximately 2.5 percent of combined load of wind is reasonable, we are aware that Section 83A requires the Distribution Companies to solicit twice for proposals and enter into long-term contracts if the proposals are reasonable and cost effective. Section 83A; see also 220 C.M.R. § 21.08(4). The PTC and ITC expired on December 31, 2013, and as of the date of this Order have not been extended (Exh. JU (rev.) at 31-32). See also I.R.C. §§ 45, 48. The timing of the solicitation that produced the proposed contracts was determined, in part, to allow winning bidders to take advantage of these tax credits prior to their expiration. D.P.U. 13-57, at 19.

The Distribution Companies stated in their initial filings that they contracted for more than 1.8 percent of load because of: (1) the competitive prices received; and (2) the uncertainty associated with the extension of the PTC (Exh. JU (rev.) at 34). We agree that the PPAs are cost effective and low cost. We also agree with DOER's argument that the status of federal tax credits and possible reduction of REC prices justified contracting for more than 1.8 percent of load. In addition, the Department notes that the Distribution Companies have not contracted for more than the four percent of load required under Section 83A. Thus, we find that it is appropriate for the Distribution Companies to procure renewable energy equal to approximately 2.5 percent of their load.

D. Bill Impacts

One of the Department's considerations in assessing a long-term contract under Section 83A with respect to the public interest is whether its bill impacts are reasonable in light of its benefits. D.P.U. 12-98, at 29; D.P.U. 11-05/11-06/11-07, at 47; D.P.U. 10-54, at 274.

The Distribution Companies expect the contracts to result in overall net bill savings for customers over the life of the contracts (Exhs. JU (rev.) at 36-37; FGE- RSF-2 (rev.); NGRID-SMM-4 (rev.); NSTAR-RDC-2 (supp.); NSTAR-RDC-3 (supp.); NSTAR-RDC-4 (supp.); WMECO-RDC-2 (supp.)). As discussed in greater detail in Section IX below, depending on the amount and actual market value of the products obtained through the contracts, a customer's bill could increase or decrease slightly in any given year but will decrease over the life of the contracts. We also expect the contracts to reduce the Distribution Companies' overall RPS compliance costs (Exh. JU (rev.) at 44). Accordingly, the Department finds that the bill impacts of the contracts are reasonable in light of the benefits of the contracts (Exhs. FGE-RSF (rev.) at 9; FGE-RSF-2 (rev.); NGRID-SSM-4; NSTAR-RDC-2, at 1; NSTAR-RDC-3, at 1; NSTAR-RDC-4, at 1; WMECO-RDC (supp.) at 6; WMECO-RDC-2 (supp.)). We address bill impacts for each company in Section IX, below.

E. Conclusion

The Department found above that the Distribution Companies selected the winning bids using a solicitation process that was open, fair, and transparent and, therefore, competitive. The Department also found that the Distribution Companies sufficiently considered alternative Section 83A-eligible renewable resources, and that no other higher net benefit, Section 83A-eligible resources were available to the Distribution Companies. In addition, the Department found that it was reasonable for the Distribution Companies to contract for approximately 2.5 percent of their load based on the competitiveness of the bids received and the status of federal tax credits.

We also found that the pricing terms of the contracts are reasonable, given the type of renewable resource being purchased. Finally, the Department found that the bill impacts of the contracts are not only acceptable, but actually advantageous to customers. Accordingly, the Department finds that the proposed long-term contracts with Iberdrola Renewables, Evergreen Wind Power, and Blue Sky West are in the public interest.

VIII. REMUNERATION

Pursuant to Section 83A, each of the Distribution Companies proposes to collect a remuneration of 2.75 percent on the annual payments under the contracts entered into after January 1, 2013 (Exh. JU (rev.) at 42-43). No party commented on the Distribution Companies' proposed remuneration.

Section 83A expressly provides an annual remuneration for an electric distribution company equal to 2.75 percent of the annual payments under a contract entered into after January 1, 2013, to compensate the company for accepting the financial obligation of the long-term contract for renewable energy. See also 220 C.M.R. § 21.07. Accordingly, the Distribution Companies may collect 2.75 percent remuneration on the annual payments made under the proposed contracts, all of which were entered into after January 1, 2013. The method of collecting that annual remuneration is addressed in Section IX, below.

IX. COST RECOVERY

Before the Department can approve a company's proposal regarding the ratemaking treatment of energy and RECs procured under the PPAs, it must determine that the company's proposal is consistent with 220 C.M.R. § 21.06. The Department's regulations provide Distribution Companies with several options regarding the use of energy and RECs procured through PPAs and the associated cost recovery. 220 C.M.R. § 21.06. The Department also must determine whether any tariff language regarding remuneration is consistent with Section 83A and 220 C.M.R. § 21.07.[39] In addition, when assessing the public interest with respect to a long-term renewable energy contract, the Department must consider whether its bill impacts are reasonable in light of its benefits and consistent with Department precedent.

Each of the Distribution Companies proposes to sell the renewable energy procured under the PPAs through the Energy Market, crediting or charging distribution customers the difference between the Energy Market revenues received from the sale of the energy and the costs for the energy incurred under the PPAs (Exh. JU (rev.) at 45). The Distribution Companies also propose to sell the Class I RECs associated with the PPAs and then credit or charge distribution customers the difference between the revenues received from the sale of the RECs and the costs of the RECs incurred under the PPAs, to the extent that each distribution company does not need the RECs to meet its RPS obligations (Exh. JU (rev.) at 45).

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[39] Each of the Distribution Companies' proposed tariffs provides for cost recovery for the proposed contracts and for cost recovery for all previously approved long-term renewable energy contracts filed pursuant to Section 83.

A. Fitchburg Proposal

1. Introduction

Fitchburg proposes to return to or recover from all distribution customers the net amount associated with the PPAs through the pricing provisions of its amended Long-Term Renewable Contract Adjustment ("LRCA") tariff, M.D.P.U. No. 239 (Exhs. JU (rev.) at 11, 43; FGE-RSF (rev.) at 5). The net amount in the LRCA will include: (1) the difference between the revenues received for the energy sold into the Energy Market and the costs for the energy under the PPAs; (2) the difference between the revenues received for the RECs either at the market price if used to meet RPS obligations or at the purchase price if sold into the market, and the costs for the RECs under the PPAs; and (3) the remuneration amount paid to Fitchburg associated with its procuring long-term contracts as allowed pursuant to Sections 83A (Exh. FGE-RSF (rev.) at 5). If the RECs are used to meet Fitchburg's RPS obligations then Fitchburg will determine a market price to be charged to basic service customers and credited to distribution customers (Exh. FGE-RSF (rev.) at 6). The net amount to be credited or charged to distribution customers is then the costs of the PPAs less the proceeds from the sale of energy and RECs (Exh. JU (rev.) at 43).

Fitchburg proposes to revise its LRCA tariff to incorporate: (1) the reduction of the annual remuneration from 4.00 percent (under Section 83) to 2.75 percent for contracts entered into on or after January 1, 2013; and (2) an additional method of establishing the market price for RECs that are used to meet its RPS obligations (Exhs. FGE-RSF (rev.) at 4; FGE-RSF-3). Fitchburg's current LRCA tariff includes two options for determining a market price for RECs: (1) the average price of RECs that are procured by Fitchburg from the REC market; or (2) the average price of RECs sold by Fitchburg into the REC market (Exh. FGE-RSF-3, at 2-3).

Fitchburg would apply this additional method of establishing a market price for RECs only if, at least 15 days prior to its annual proposed LRCA factor filing, Fitchburg does not sell RECs through a procurement consistent with the two other pricing methods currently contained in Fitchburg's LRCA tariff (Exh. FGE-RSF (rev.) at 7). The proposed third method establishes a market price for RECs by reference to price quotes in bids and offers for Massachusetts Class I RECs from one or more brokers of renewable energy attributes (Exh. FGE-RSF (rev.) at 7).

Fitchburg proposes to adjust the LRCA factor each year based upon: (1) the contract prices in effect and forecasted deliveries under the proposed contracts; and (2) the reconciliation of the actual costs incurred under the proposed contracts and the revenues collected through the LRCA factor in the prior year (Exh. FGE-RSF (rev.) at 5-6).

2. Positions of the Parties

Fitchburg states that its cost recovery proposal is permitted under Section 83A and 220 C.M.R. § 21.06 (Distribution Companies Brief at 19). Fitchburg maintains that its proposed third pricing alternative for RECs is similar to the pricing method Fitchburg follows in establishing the RPS compliance cost component of its basic service rates (Distribution Companies Brief at 21). Fitchburg argues that the Department should approve the cost recovery proposal for these Section 83A PPAs (Distribution Companies Brief at 22). No other party commented on Fitchburg's cost recovery proposal.

3. Analysis and Findings

Fitchburg proposes to sell the energy procured through the PPAs through the Energy Market, crediting or charging the difference between the Energy Market revenues and the PPA costs to all distribution customers (Exh. JU (rev.) at 43). Fitchburg proposes to sell the RECs and credit the net proceeds to distribution customers if it does not need the RECs to meet its RPS obligations (Exh. JU (rev.) at 44). The proposed treatment of the energy and RECs procured under the proposed PPAs complies with Section 83A and 220 C.M.R. § 21.06(1). Regarding the cost recovery related to the proceeds from the sale of the energy and RECs, Fitchburg proposes to credit or charge to all distribution customers the cost of the PPAs less proceeds from the sale of energy and RECs (Exh. JU (rev.) at 43). The Department has previously found that crediting or charging all distribution customers the above- or below-market costs is appropriate and in the public interest. NSTAR Electric Company, D.P.U. 11-05/11-06/11-07, at 66-67 (2011); Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, D.P.U. 10-54, at 335-336 (2010). The Department finds that Fitchburg's proposal is consistent with Section 83A, 220 C.M.R. § 21.06(2), and Department precedent.

In addition, Fitchburg proposes to revise its LRCA tariff to incorporate: (1) the reduction of the annual remuneration from 4.00 percent to 2.75 percent for contracts entered into on or after January 1, 2013; and (2) an additional method of establishing the market price for RECs that are used to meet its RPS obligations (Exhs. FGE-RSF (rev.) at 4; FGE-RSF-3). The Department finds that the language in Fitchburg's LRCA tariff regarding remuneration is consistent with Section 83A and 220 C.M.R. § 21.07. Regarding the alternative method for pricing RECs, Fitchburg explains that its RPS obligation may shrink in the future due to municipal aggregation in its service territory (Tr. at 148-149). Municipal aggregation would have the effect of reducing the number of Fitchburg's basic service customers. As a result, Fitchburg proposes an additional method to determine a market price for RECs (Tr. at 148-149). The Department finds Fitchburg's rationale for proposing an additional method for determining a market price for RECs to be reasonable in light of potential municipal aggregation in Fitchburg's service territory. Therefore, the Department finds that Fitchburg's proposed alternative method for determining a market price for RECs is consistent with Section 83A, 220 C.M.R. § 21.06(2), and Department precedent.

A critical consideration for the Department in assessing the public interest of a long-term renewable energy contract is whether the impacts of the PPAs on customer bills are reasonable in light of the PPA benefits. D.P.U. 10-54, at 274. Pursuant to Section 83A and 220 C.M.R. § 21.05(1)(c), long-term renewable energy contracts must be cost effective to Massachusetts electric ratepayers over the term of the contract. Fitchburg provides an illustrative analysis of likely bill impacts, based on the current market environment, noting that the proposed commercial operation dates of the renewable generating facilities range from 2015 to 2016 (Exhs. FGE-RSF (rev.) at 9; FGE-RSF-2 (rev.)). Fitchburg estimates bill impacts for each rate class and for a range of different consumption levels within each rate class (Exh. FGE-RSF-2 (rev.)). The Department notes that the bill impacts anticipated based on the current market environment represent a net savings to ratepayers in every consumption level for every rate class and, therefore, are reasonable (Exh. FGE-RSF-2 (rev.)).

For the reasons discussed above, the Department finds that Fitchburg's proposed ratemaking treatment of the products it will purchase under the PPAs is consistent with Section 83A, Department regulations, and Department precedent, and is in the public interest. Accordingly, Fitchburg's proposed ratemaking treatment is approved. Further, the Department finds that Fitchburg's proposed cost recovery mechanism is consistent with Section 83A, Department regulations, and Department precedent, is in the public interest, and will result in just and reasonable rates pursuant to

G.L. c. 164, § 94. Finally, the Department approves the revised language contained in Fitchburg's proposed LRCA tariff, M.D.P.U. No. 239. Accordingly, the Department directs Fitchburg to file within ten days of the date of this Order a revised LRCA tariff with an updated effective date.

B. National Grid Proposal

1. Introduction

National Grid proposes to return to or recover from all distribution customers the net proceeds associated with the PPAs through (1) the pricing provision of its amended Renewable Energy Recovery Provision ("RERP") tariff, M.D.P.U. No. 1221, and (2) the reconciliation provision of its Basic Service Adjustment Provision ("BSAP") tariff, M.D.P.U. No. 1222 (Exh. NGRID-SMM at 7-10). The amount recovered through the RERP is: (1) the difference between the revenues received for the energy procured under the Section 83 and Section 83A contracts sold into the Energy Market, and the costs for the energy under these contracts; (2) the difference between the revenues received for the RECs procured under the Section 83 and Section 83A contracts at the market price for the RECs used to meet the Company's basic service RPS obligations, and the costs for the RECs under these contracts; (3) the remuneration amount paid to National Grid associated with its procurement of long-term contracts, as allowed pursuant to Section 83 and Section 83A; and (4) the reconciliation of the prior year's balance in the RERP (Exh. NGRID-SMM at 7-9). The amount reconciled through the reconciliation provision of the BSAP is the difference between the revenues received for the RECs procured under the Section 83 and Section 83A contracts that are sold into the market (i.e., RECs that are not used for RPS compliance) and the cost for these RECs under the Section 83 and Section 83A contracts (Exh. NGRID-SMM at 9). The cost of the RECs that are procured under the Section

83 and Section 83A contracts that are used to meet National Grid's basic service RPS obligations is recovered from basic service customers at the market price, not the contract price for the RECs (Exh. JU (rev.) at 44).

National Grid proposes to revise its RERP tariff to incorporate: (1) National Grid's proposal to use the products purchased under the Section 83A contracts differently from the way it has under previous long-term renewable energy contracts; and (2) the annual remuneration of 2.75 percent for Section 83A contracts (Exh. NGRID-SMM at 6-8). In addition, the Company proposes to amend its BSAP tariff to include: (1) an adjustment in the reconciliation process to include the revenue associated with the above/below market costs of Section 83A contracts billed through the Renewable Energy Recovery ("RER") factor; and (2) the costs of purchasing and the revenues from selling the RECs not retained to meet RPS obligations (Exh. DPU-NGRID-1-1).

National Grid proposes to adjust the RER factor each year based upon: (1) the contract prices in effect and forecasted deliveries under the proposed contracts; and (2) the reconciliation of the actual costs incurred under the proposed contracts and the revenues collected through the RER factor in the prior year (Exhs. NGRID-SMM at 7-9; NGRID-SMM-1).

2. Positions of the Parties

National Grid states that its cost recovery proposal is permitted under Section 83A and 220 C.M.R. § 21.06 (Distribution Companies Brief at 5). National Grid argues that the Department should approve the cost recovery proposal for these Section 83A PPAs (Distribution Companies Brief at 22). No other party commented on National Grid's cost recovery proposal.

3. Analysis and Findings

National Grid proposes to sell the energy procured through the PPAs through the Energy Market, crediting or charging the difference between the Energy Market revenues received and the PPA costs incurred to all distribution customers (Exh. JU (rev.) at 43). National Grid proposes to sell the RECs and credit the net proceeds to all distribution customers through the basic service reconciliation if it does not need the RECs to meet its RPS obligations (Exhs. JU (rev.) at 44; NGRID-SMM at 10-11). We find that the proposed treatment of the energy and RECs procured under the PPAs complies with Section 83A and 220 C.M.R. § 21.06(1). National Grid proposes to credit or charge to all distribution customers through the RER factor the cost of the PPAs, less the revenues from the sale of the energy, and less the market value of RECs used to satisfy the RPS requirements of providing basic service, pursuant to 225 C.M.R. § 14.07 (Exh. JU (rev.) at 43-44). National Grid also proposes to sell RECs in excess of its RPS obligation into the market and to reconcile any differences between the contract price and the market price in the BSAP (Exhs. NGrid-SMM at 10-11; DPU-NGRID-1-1). The Department finds that it is reasonable for the proceeds from the sale of excess RECs to be applied to the BSAP because the proceeds will be collected from or returned to all distribution customers. The Department previously has found that crediting or charging all distribution customers the above/below market costs is appropriate and in the public interest. D.P.U. 11-05/11-06/11-07, at 66-67; D.P.U. 10-54, at 335-336. The Department finds that National Grid's proposal is consistent with Section 83A, 220 C.M.R. § 21.06(2), Department precedent, and is in the public interest.

In addition, National Grid proposes to revise its RERP tariff to incorporate: (1) the annual remuneration of 2.75 percent for Section 83A contracts; and (2) National Grid's intention to use the products procured under the Section 83A contracts differently from its approach under previous long-term renewable energy contracts (Exhs. NGrid-SMM at 6-9; NGrid-SMM-1). The Department finds that the language in National Grid's RERP tariff regarding remuneration is consistent with Section 83A and 220 C.M.R. § 21.07. Regarding the use of the products procured under the proposed PPAs, the Department finds that the proposed amendment to the language of the RERP is also consistent with Section 83A, 220 C.M.R. § 21.06(2), and Department precedent.

A critical consideration for the Department in assessing the public interest of a long-term renewable energy contract is whether the impacts of the PPAs on customer bills are reasonable in light of the PPA benefits. D.P.U. 10-54, at 274. Pursuant to Section 83A, and 220 C.M.R. § 21.05(1)(c), a long-term renewable energy contract must be cost effective to Massachusetts electric ratepayers over the term of the contract. National Grid provides an illustrative analysis of likely bill impacts, based on the current market environment, noting that the proposed commercial operational dates range from 2015 to 2016 (Exhs. NGRID-SMM at 12; NGRID-SMM-4). National Grid estimates bill impacts for each rate class and for a range of different consumption levels within each rate class (Exh. NGRID-SMM-4). The Department notes that the bill impacts anticipated based on the current market environment represent a net savings to ratepayers in every consumption level for every rate class and, therefore, the PPAs are reasonable (Exh. NGRID-SMM-4).

Further, National Grid proposes to modify its BSAP, M.D.P.U. No. 1222 to include language that incorporates in the basic service reconciliation the revenue associated with the above/below market costs of Section 83A contracts billed through the RERP, the cost of purchasing RECs under

Section 83A contracts, and the proceeds from the sale of those RECs purchased but not retained by the Company (Exhs. DPU-NGRID-1-1; NGRID-SMM at 10-11). The Department finds, with one exception, that the proposed changes to the BSAP are reasonable because the tariff recovers the above/below-market costs of the Section 83 and Section 83A contracts from all distribution customers, consistent with Section 83A. The Department notes, however, that the language of the BSAP tariff inequitably includes the estimated above-market costs of Section 83 and Section 83A contracts, without reference to any estimated below-market costs. The Department, therefore, directs the Company to provide a revised tariff to remedy the omission of estimated below-market costs in M.D.P.U. No. 1222, Sheet 2, paragraph 2, line 6.

For the reasons discussed above, the Department finds that National Grid's proposed ratemaking treatment of the products it will purchase under the PPAs is consistent with Section 83A, Department regulations, and Department precedent, and is in the public interest. Accordingly, National Grid's proposed ratemaking treatment is approved. Further, the Department finds that National Grid's proposed cost recovery mechanism is consistent with Section 83A, Department regulations, and Department precedent, is in the public interest, and will result in just and reasonable rates pursuant to G.L. c. 164, § 94. Finally, the Department approves the revised language contained in National Grid's proposed RERP tariff M.D.P.U. No. 1221 and rejects the revised language of National Grid's proposed BASF tariff M.D.P.U. No. 1222. Accordingly, the Department directs National Grid within ten days of the date of this Order to file: (1) a revised RERP tariff M.D.P.U. No. 1221 with an updated effective date; and (2) a revised BASF tariff M.D.P.U. No. 1222 with an updated effective date and the change to the language of the tariff set forth above.

C. NSTAR Proposal

1. Introduction

NSTAR proposes to return to or recover from all distribution customers the net amount associated with the PPAs through the pricing provisions of its amended LRCA tariff, M.D.P.U. No. 164B (Exhs. JU (rev.) at 11, 43; NSTAR-RDC (supp.) at 2-3). The net amount in the LRCA will include: (1) the difference between the revenues received for the energy sold into the Energy Market and the costs for the energy under the PPAs; (2) the difference between the revenues received for the RECs either at the market price if used to meet RPS obligations or at the purchase price if sold into the market, and the costs for the RECs under the PPAs; and (3) the remuneration amount paid to NSTAR associated with its procuring long-term contracts as allowed pursuant to Sections 83A (Exh. NSTAR-RDC at 4). If the RECs are used to meet NSTAR's RPS obligations then the market price, not the contract price for the RECs, will be charged to basic service customers and credited to distribution customers (Exh. JU (rev.) at 44). The net amount to be credited or charged to distribution customers is then the costs of the PPAs less the proceeds from the sale of energy and RECs (Exh. JU (rev.) at 45).

NSTAR proposed revisions to its LRCA tariff that incorporate the reduction of the annual remuneration from 4.00 percent to 2.75 percent for contracts entered into on or after January 1, 2013 (Exhs. NSTAR-RDC at 4; NSTAR-RDC-5). NSTAR proposes to adjust the LRCA factor each year based upon: (1) the contract prices in effect and forecasted deliveries under the proposed contracts; and (2) the reconciliation of the actual costs incurred under the proposed contracts and the revenues collected through the LRCA factor in the prior year (Exh. NSTAR-RDC at 5).

2. Positions of the Parties

NSTAR states that its cost recovery proposal is permitted under Section 83A and 220 C.M.R. § 21.06 (Distribution Companies Brief at 19). NSTAR argues that the Department should approve the cost recovery proposal for these Section 83A PPAs (Distribution Companies Brief at 22). No other party commented on NSTAR's cost recovery proposal.

3. Analysis and Findings

NSTAR proposes to sell the energy procured through the PPAs through the Energy Market, crediting or charging the difference between the Energy Market revenues and the PPA costs to all distribution customers (Exh. JU (rev.) at 43). NSTAR proposes to sell the RECs and credit the proceeds to distribution customers if it does not need the RECs to meet its RPS obligations (Exh. JU (rev.) at 44). The proposed treatment of the energy and RECs procured under the proposed PPAs complies with Section 83A and 220 C.M.R. § 21.06(1). Regarding the cost recovery related to the proceeds from the sale of the energy and RECs, NSTAR proposes to credit or charge to all distribution customers the cost of the PPAs less proceeds from the sale of energy and RECs (Exh. JU (rev.) at 44). The Department previously has found that crediting or charging all distribution customers the above- or below-market costs is appropriate and in the public interest. D.P.U. 11-05/11-06/11-07, at 66-67; D.P.U. 10-54, at 335-336. The Department finds that NSTAR's proposal is consistent with Section 83A, 220 C.M.R. § 21.06(2), and Department precedent.

In addition, NSTAR proposes to revise its LRCA tariff to incorporate the reduction of the annual remuneration from 4.00 percent to 2.75 percent for contracts entered into on or after January 1, 2013 (Exhs. NSTAR-RDC at 4; NSTAR-RDC-5). The Department finds that the language in NSTAR's LRCA tariff regarding remuneration is consistent with Section 83A and 220 C.M.R. § 21.07.

A critical consideration for the Department in assessing the public interest of a long-term renewable energy contract is whether the impacts of the PPAs on customer bills are reasonable in light of the PPA benefits. D.P.U. 10-54, at 274. Pursuant to Section 83A and 220 C.M.R. § 21.05(1)(c), long-term renewable energy contracts must be cost effective to Massachusetts electric ratepayers over the term of the contract. NSTAR provides an illustrative analysis of likely bill impacts, based on the current market environment, noting that the proposed commercial operational dates of the renewable generating facilities range from 2015 to 2016 (Exhs. NSTAR-RDC at 4; NSTAR-RDC-2; NSTAR-RDC-3; NSTAR-RDC-4). NSTAR estimates bill impacts for each rate class and for a range of different consumption levels within each rate class (Exhs. NSTAR-RDC-2; NSTAR-RDC-3; NSTAR-RDC-4). The Department notes that the bill impacts anticipated based on the current market environment represent a net savings to ratepayers in every consumption level for every rate class and are, therefore, reasonable (Exhs. NSTAR-RDC-2; NSTAR-RDC-3; NSTAR-RDC-4).

For the reasons discussed above, the Department finds that NSTAR's proposed ratemaking treatment of the products it will purchase under the PPAs is consistent with Section 83A, Department regulations, and Department precedent, and is in the public interest. Accordingly, NSTAR's proposed ratemaking treatment is approved. Further, the Department finds that NSTAR's proposed cost recovery mechanism is consistent with Section 83A, Department regulations, and Department precedent, is in the public interest, and will result in just and reasonable rates pursuant to G.L. c. 164, § 94. Finally, the Department approves the revised language contained in NSTAR's proposed LRCA tariff, M.D.P.U. No. 164B. Accordingly, the Department directs NSTAR to file within ten days of the date of this Order a revised LRCA tariff with an updated effective date.

D. WMECo Proposal

1. Introduction

WMECo proposes to return to or recover from all distribution customers the net amount associated with the PPAs through the pricing provisions of its amended LRCA tariff, M.D.P.U. No. 1051B. (Exhs. JU (rev.) at 11, 43; WMECO-RDC (supp.) at 5). The net amount in the LRCA includes: (1) the difference between the revenues received for the energy sold into the Energy Market and the costs for the energy sold under the PPAs; (2) the difference between the revenues received for the RECs either at the market price if used to meet RPS obligations or at the purchase price if sold into the market, and the costs for the RECs under the PPAs ; and (3) the remuneration amount paid to WMECo associated with its procuring long-term contracts as allowed pursuant to Sections 83A (Exh. WMECO-RDC (supp.) at 4). WMECo anticipates that it will not need to use the RECs to meet its RPS obligations (Exh. JU (rev.) at 44).

WMECo proposes to revise its LRCA tariff to incorporate the reduction of the annual remuneration from 4.00 percent to 2.75 percent for contracts entered into on or after January 1, 2013 (Exhs. WMECO-RDC (supp.) at 3; WMECO-RDC-3). WMECo proposes to adjust the LRCA factor each year based upon: (1) the contract prices in effect and forecasted deliveries under the proposed contracts; and (2) the reconciliation of the actual costs incurred under the proposed contracts and the revenues collected through the LRCA factor in the prior year (Exh. WMECO-RDC (supp.) at 4-5).

2. Positions of the Parties

WMECo states that its cost recovery proposal is permitted under Section 83A and 220 C.M.R. § 21.06 (Distribution Companies Brief at 19). WMECo argues that the Department should approve the cost recovery proposal for these Section 83A PPAs (Distribution Companies Brief at 22). No other party commented on WMECo's cost recovery proposal.

3. Analysis and Findings

WMECo proposes to sell the renewable energy procured through the PPAs through the Energy Market, crediting or charging the difference between the Energy Market revenues and the PPA costs to all distribution customers (Exh. JU (rev.) at 43). WMECo proposes to sell the RECs and credit the net proceeds to distribution customers (Exh. JU (rev.) at 43). The proposed treatment of the energy and RECs procured under the proposed PPAs complies with Section 83A and 220 C.M.R. § 21.06(1). Regarding the cost recovery related to the proceeds from the sale of the energy and RECs, WMECo proposes to credit or charge to distribution customers the cost of the PPAs less proceeds from the sale of energy and RECs (Exh. JU (rev.) at 43). The Department has previously found that crediting or charging all distribution customers the above- or below-market costs is appropriate and in the public interest. D.P.U. 11-05/11-06/11-07, at 66-67; 10-54, at 335-336. The Department finds that WMECo's proposal is consistent with Section 83A, 220 C.M.R. § 21.06(2), and Department precedent.

In addition, WMECo proposes to revise its LRCA tariff to incorporate the reduction of the annual remuneration from 4.00 percent to 2.75 percent for contracts entered into on or after January 1, 2013 (Exhs. WMECO-RDC (supp.) at 3; WMECO-RDC-3). The tariff language regarding remuneration is consistent with Section 83A and 220 C.M.R. § 21.07.

A critical consideration for the Department in assessing the public interest of a long-term contract is whether the impacts of the PPAs on customer bills are reasonable in light of the PPA benefits. D.P.U. 10-54, at 274. Pursuant to Section 83A and 220 C.M.R. § 21.05(1)(c), long-term contracts must be cost effective to Massachusetts electric ratepayers over the term of the contract. WMECo provides an illustrative analysis of bill impacts that are likely, based on the current market environment, noting that the proposed commercial operational dates range from 2015 to 2016 (Exhs.WMECO-RDC (supp.) at 6; WMECO-RDC-2 (supp.)). WMECo estimates bill impacts for each rate class and for a range of different consumption levels within each rate class (Exh. WMECO-RDC-2 (supp.)). The Department notes that the bill impacts anticipated based on the current market environment represent a net savings to ratepayers in every consumption level for every rate class and are, therefore, reasonable (Exh. WMECO-RDC-2 (supp.)).

For the reasons discussed above, the Department finds that WMECo's proposed treatment of the products it will purchase under the PPAs is consistent with Section 83A, Department regulations, and Department precedent, and is in the public interest. Accordingly, WMECo's proposed treatment of the energy and RECs is approved. Further, the Department finds that WMECo's proposed cost recovery mechanism is consistent with Section 83A, Department regulations, Department precedent, is in the public interest, and will result in just and reasonable rates pursuant to G.L. c. 164, § 94. Finally, the Department approves the revised language contained in WMECo's proposed LRCA tariff, M.D.P.U. No. 1051B. Accordingly, the Department directs WMECo to file within ten days of the date of this Order a revised LRCA tariff with an updated effective date.

X. RECOMMENDATIONS FOR FUTURE SECTION 83A RFP

A. Introduction

The Attorney General and DOER recommend changes in future Section 83A solicitations to improve the RFP process (Attorney General Brief at 27-29; DOER Brief at 22-27). We address these recommendations below.

1. Recommendations

a. Attorney General

The Attorney General suggests that a revision to the future Section 83A RFP should require the Distribution Companies to explicitly account in their bid evaluation for incremental transmission costs beyond those necessary to interconnect a specific facility to the ISO-NE PTF (Attorney General Brief at 28, citing Exh. AG-JCJW-1, at 22, 30). Specifically, the Attorney General suggests that the Distribution Companies must be required to consider potential incremental transmission upgrades required to interconnect a bundle of projects to the ISO-NE grid, and to document all assumptions used in this analysis (Attorney General Brief at 29, citing Tr. at 240). The Attorney General contends that any assumptions should be vetted by third parties such as DOER, the Attorney General, and ISO-NE to further ensure transparency (Attorney General Brief at 29).

b. DOER

DOER suggests that subsequent Section 83A solicitations would benefit from improvement based on lessons learned in the current process (DOER Brief at 22). Specifically, DOER proposes the following six changes to the RFP process: (1) keep the RFP process open until all PPAs are binding on all parties and appropriate security deposits have been obtained; (2) require written documentation of the third stage of evaluation; (3) require consideration of project viability during the stage three evaluation; (4) evaluate interconnection service levels in bid analysis; (5) adopt a fundamental-type REC forecast method; and (6) incorporate known transmission constraints into the energy forecast (DOER Brief at 22-27). DOER recommends that the Distribution Companies, in consultation with DOER and the Attorney General, address these issues in developing the next Section 83A RFP (DOER Brief at 28).

DOER suggests changes to the stage three evaluation criteria to clarify the level of analysis and criteria that are used to assess project viability (DOER Brief at 22-24). DOER states that such an analysis is important given the shortage of Class I RECs relative to RPS goals, and maintains that if the selected projects ultimately are not built, this would exacerbate the REC shortage, putting upward pressure on REC prices (DOER Brief at 23). In addition to clarifying evaluation criteria in future RFPs, DOER suggests that the Distribution Companies document the stage three review and analysis in writing and that DOER should be included in stage three deliberations as a non-voting participant (DOER Brief at 24).

DOER also notes that ISO-NE defines two interconnection levels that the Distribution Companies should evaluate: (1) Capacity Network Resource Integration Service ("CNRIS"); and (2) Network Resource Integration Service (DOER Brief at 24-25). DOER contends that the draft PPA approved by the Department required the seller to obtain CNRIS interconnection service, but that the Distribution Companies changed this provision during negotiations with First Wind for the Oakfield Wind and Bingham Wind projects (DOER Brief at 25, citing Exh. DOER-1-8). DOER argues that the Distribution Companies should consider transmission interconnection service levels in evaluating projects in future solicitations since CNRIS service is desirable all else being equal between two projects (DOER Brief at 25-26).

DOER also argues that a fundamental-type REC market forecast should be used in the next RFP process as this forecast method is less driven by assumptions regarding the balance between supply and demand over long periods of time, and is thus better for assessing long-term renewable energy contract proposals (DOER Brief at 26-27). In addition, DOER suggests collaborating with ISO-NE in order to determine how to properly consider known near-term and mid-term transmission constraints in the market forecast for future solicitations (DOER Brief at 27).

c. Distribution Companies

The Distribution Companies assert that the Attorney General's and DOER's recommendations should be considered when the Distribution Companies consult with DOER and the Attorney General with respect to the timetable and method of solicitation for future Section 83A solicitations (Distribution Companies Reply Brief at 21, citing D.P.U. 11-05/11-06/11-07, at 52).

2. Conclusion

Section 83A and the Department's regulations at 220 C.M.R. § 21.03(1) require the Distribution Companies to jointly conduct two competitive solicitations for renewable energy prior to December 31, 2016. Therefore, the Distribution Companies are required to conduct another joint solicitation for renewable energy before the end of 2016. The Distribution Companies also are required to consult with DOER on the method of solicitation and the timetable, and with the Attorney General and DOER regarding the choice of contract and solicitation methods, prior to filing their proposal with the Department for approval. See Section 83A; 220 C.M.R. § 21.04.

The appropriate time to address recommendations for future solicitations is during future solicitation and timetable proceedings filed with the Department and/or during the required consultation among the Distribution Companies, DOER, and the Attorney General. See D.P.U. 11-05/11-06/11-07, at 49. However, because there is only one additional solicitation required under Section 83A, the Department suggests that the Distribution Companies consider the Attorney General's and DOER's recommendations raised in this proceeding.

Prior to the commencement of the evidentiary hearing in these proceedings, the Distribution Companies withdrew twelve of the 24 PPAs originally filed with the Department (Motion to Withdraw, October 24, 2013, at 2-3; Exh. DPU-7-3). The Distribution Companies withdrew the four PPAs associated with the Iberdrola Fletcher Mountain Project because, as allowed under the contract, the project developer voided the contract upon failure to obtain corporate approval by a certain date (Motion to Withdraw, October 24, 2013, at 2-3). The Distribution Companies terminated the PPAs associated with Exergy's Passamaquoddy Wind and Peskotmuhkati Wind projects based on the developer's failure to post the required security in accordance with the proposed contracts, and subsequently withdrew these eight PPAs from Department consideration (Exh. DPU-7-3; see also Motion to Withdraw, November 21, 2013). The Distribution Companies allowed compliance with these contract provisions (i.e., corporate board approval and posting of security) to occur after the closing of the RFP and filing of the PPAs with the Department to allow developers to take advantage of expiring federal tax credits (Tr. at 138-139). Because future solicitations should not be subject to the same time pressure, we expect that any future PPAs filed with the Department will ensure that all required deposits and corporate approvals will have been secured prior to filing with the Department.

Regarding the stage three evaluation, DOER also suggests that the Distribution Companies document the stage three evaluation process in writing to improve transparency and facilitate review (DOER Brief at 24). The Department agrees. Written documentation will improve the transparency of the third stage of evaluation and will facilitate review by the Department and other stakeholders. We expect that the Distribution Companies will file such documentation in subsequent Section 83A proceedings.

Further, DOER suggests adding criteria to the stage three evaluation, including a review of project viability and interconnection service level (DOER Brief at 24). The Department encourages the Distribution Companies, DOER, and the Attorney General to collaborate on developing additional criteria for the stage three evaluation, and the Department will review those suggestions in future reviews of solicitation method.

Finally, DOER suggests changes to the REC forecast methodology and the transmission assumptions of the energy forecast (DOER Brief at 26-27). As discussed above, there are two primary methods to model REC prices: (1) a supply and demand forecast; and (2) a fundamental-type forecast (Tr. at 176-177). While both methods produce viable results, DOER and the Attorney General suggest that a fundamental type-forecast may be more appropriate when reviewing the benefits of long-term contracts for renewable energy (DOER Brief at 26; Attorney General Brief at 26). Both the supply and demand and fundamental-type forecast methods are reliable means to project REC revenues; however, a fundamental-type forecast may be more appropriate when estimating future REC revenues from a long-term renewable energy contract. We encourage the parties to collaborate, and include ISO-NE if required, to determine the most appropriate assumptions to be used in the energy forecast.

The Attorney General also suggests that future solicitations include an analysis in the stage three evaluation of potential future incremental transmission costs necessary to interconnect a bundle of projects (Attorney General Brief at 29). As discussed in Section V.D above, the Department found that it is not reasonable to assign future incremental transmission costs to any one particular project, other than those required to interconnect that project to the ISO-NE PTF. In addition, we found that including such speculative costs in stage three of the evaluation process would not be a valid way to evaluate projects within a Section 83A RFP. We therefore reject the Attorney General's recommendation in this regard.

XI. ORDER

Accordingly, after notice, hearing and due consideration, it is:

ORDERED: That the power purchase agreement between Fitchburg Gas and Electric Light Company d/b/a Unitil and Iberdrola Renewables, LLC for renewable energy and renewable energy certificates filed on September 20, 2013, pursuant to St. 2008, c. 169, § 83A and 220 C.M.R. § 21.00 et seq., is APPROVED; and it is

FURTHER ORDERED: That the power purchase agreement between Fitchburg Gas and Electric Light Company d/b/a Unitil and Evergreen Wind Power II, LLC for renewable energy and renewable energy certificates filed on September 20, 2013, pursuant to St. 2008, c. 169, § 83A and 220 C.M.R. § 21.00 et seq., is APPROVED; and it is

FURTHER ORDERED: That the power purchase agreement between Fitchburg Gas and Electric Light Company d/b/a Unitil and Blue Sky West, LLC for renewable energy and renewable energy certificates filed on September 20, 2013, pursuant to St. 2008, c. 169, § 83A and 220 C.M.R. § 21.00 et seq., is APPROVED; and it is

FURTHER ORDERED: That the proposed long-term renewable contract recovery mechanism tariff M.D.P.U. No. 239 filed by Fitchburg Gas and Electric Light Company d/b/a Unitil is DISALLOWED; and it is

FURTHER ORDERED: That Fitchburg Gas and Electric Light Company d/b/a Unitil shall file within ten days of the date of this Order a long-term renewable contract recovery mechanism tariff in compliance with the directive in this Order; and it is

FURTHER ORDERED: That the power purchase agreement between Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, and Iberdrola Renewables, LLC for renewable energy and renewable energy certificates filed on September 20, 2013, pursuant to St. 2008, c. 169, § 83A and 220 C.M.R. § 21.00 et seq., is APPROVED; and it is

FURTHER ORDERED: That the power purchase agreement between Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, and Evergreen Wind Power II, LLC for renewable energy and renewable energy certificates filed on September 20, 2013, pursuant to St. 2008, c. 169, § 83A and 220 C.M.R. § 21.00 et seq., is APPROVED; and it is

FURTHER ORDERED: That the power purchase agreement between Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, and Blue Sky West, LLC for renewable energy and renewable energy certificates filed on September 20, 2013, pursuant to St. 2008, c. 169, § 83A and 220 C.M.R. § 21.00 et seq., is APPROVED; and it is

FURTHER ORDERED: That the proposed renewable energy recovery provision tariff M.D.P.U. No. 1221 filed by Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, is DISALLOWED; and it is

FUTHER ORDERED: That Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, shall file within ten days of the date of this Order a renewable energy provision tariff in compliance with the directive in this Order; and it is

FURTHER ORDERED: That the proposed basic service adjustment provision tariff, M.D.P.U. No. 1222 filed by Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, is DISALLOWED; and it is

FURTHER ORDERED: That Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, shall file within ten days of the date of this Order a basic service adjustment provision tariff in compliance with the directives in this Order; and it is

FURTHER ORDERED: That the power purchase agreement between NSTAR Electric Company and Iberdrola Renewables, LLC for renewable energy and renewable energy certificates filed on September 20, 2013, pursuant to St. 2008, c. 169, § 83A and 220 C.M.R. § 21.00 et seq., is APPROVED; and it is

FURTHER ORDERED: That the power purchase agreement between NSTAR Electric Company and Evergreen Wind Power II, LLC for renewable energy and renewable energy certificates filed on September 20, 2013, pursuant to St. 2008, c. 169, § 83A and 220 C.M.R. § 21.00 et seq., is APPROVED; and it is

FURTHER ORDERED: That the power purchase agreement between NSTAR Electric Company and Blue Sky West, LLC for renewable energy and renewable energy certificates filed on September 20, 2013, pursuant to St. 2008, c. 169, § 83A and 220 C.M.R. § 21.00 et seq., is APPROVED; and it is

FURTHER ORDERED: That the proposed long-term renewable contract adjustment mechanism tariff M.D.P.U. No. 164B filed by NSTAR Electric Company is DISALLOWED; and it is

FURTHER ORDERED: That NSTAR Electric Company shall file within ten days of the date of issuance of this Order a long-term renewable contract adjustment mechanism tariff in compliance with the directive in this Order; and it is

FURTHER ORDERED: That the power purchase agreement between Western Massachusetts Electric Company and Iberdrola Renewables, LLC for renewable energy and renewable energy certificates filed on September 20, 2013, pursuant to St. 2008, c. 169, § 83A and 220 C.M.R. § 21.00 et seq., is APPROVED; and it is

FURTHER ORDERED: That the power purchase agreement between Western Massachusetts Electric Company and Evergreen Wind Power II, LLC for renewable energy and renewable energy certificates filed on September 20, 2013, pursuant to St. 2008, c. 169, § 83A and 220 C.M.R. § 21.00 et seq., is APPROVED; and it is

FURTHER ORDERED: That the power purchase agreement between Western Massachusetts Electric Company and Blue Sky West, LLC for renewable energy and renewable energy certificates filed on September 20, 2013, pursuant to St. 2008, c. 169, § 83A and 220 C.M.R. § 21.00 et seq., is APPROVED; and it is

FURTHER ORDERED: That the proposed long-term renewable contract adjustment mechanism tariff M.D.P.U. No. 1051B filed by Western Massachusetts Electric Company is DISALLOWED; and it is

FURTHER ORDERED: That Western Massachusetts Electric Company shall file within ten days of issuance of this Order a long-term renewable contract adjustment mechanism tariff in compliance with the directive in this Order; and it is

FURTHER ORDERED: That Fitchburg Gas and Electric Light Company d/b/a Unitil, Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, NSTAR Electric Company and Western Massachusetts Electric Company shall comply with all other directives contained in the Order.

By Order of the Department,

/s/
Ann G. Berwick, Chair

/s/
Jolette A. Westbrook, Commissioner

/s/
David W. Cash, Commissioner

An appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part. Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, order or ruling of the Commission, or within such further time as the Commission may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. G.L. c. 25, § 5.