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March 22, 2019

Mark D. Marini, Secretary
Department of Public Utilities
One South Station, 5th Floor
Boston, Massachusetts 02110

RE: NSTAR Electric Company d/b/a Eversource Energy; Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid; Fitchburg Gas and Electric Company d/b/a Unitil, D.P.U. 18-64/18-65/18-66

Dear Secretary Marini:

Enclosed for filing in the above-captioned matters please find the Initial Brief of the Office of the Attorney General. Please contact me if you have any questions.

Thank you for your attention to this matter.

Sincerely,

/s/ Elizabeth Mahony

Elizabeth Mahony
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Enclosure

cc: Alan Topalian, Hearing Officer
Service List

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COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

NSTAR Electric Company d/b/a Eversource Energy	**D.P.U. 18-64**
Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid	**D.P.U. 18-65**
Fitchburg Gas and Electric Light Company d/b/a Unitil	**D.P.U. 18-66**

INITIAL BRIEF OF THE OFFICE OF THE ATTORNEY GENERAL

Respectfully submitted,

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Elizabeth Mahony
Matthew E. Saunders
Assistant Attorneys General

March 22, 2019

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TABLE OF CONTENTS

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COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

NSTAR Electric Company d/b/a Eversource Energy	**D.P.U. 18-64**
Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid	**D.P.U. 18-65**
Fitchburg Gas and Electric Light Company d/b/a Unitil	**D.P.U. 18-66**

INITIAL BRIEF OF THE OFFICE OF
THE ATTORNEY GENERAL

I. INTRODUCTION

On July 23, 2018, the Massachusetts Electric Distribution Companies ("EDCs")[1] each filed a petition with the Massachusetts Department of Public Utilities ("Department") for approval of long-term power purchase agreements ("Proposed PPAs") and transmission services agreements ("Proposed TSAs") pursuant to Section 83D of an Act Relative to Green Communities, St. 2008, c. 169, as amended by St. 2016, c. 188 ("Section 83D") and 220 CMR § 24.00. The Proposed PPAs and TSAs govern the terms of the EDCs' collective purchase of 9,554,940 megawatt hours ("MWh") of energy output and the associated renewable energy certificates ("RECs") from H.Q.

[1] The EDCs include three companies in Massachusetts: NSTAR Electric Company d/b/a Eversource Energy; Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid; and Fitchburg Gas and Electric Light Company d/b/a Unitil.

Energy Services (U.S.) Inc. (“HQ”), which will be delivered over Central Main Power Company’s (“CMP”) New England Clean Energy Connect Transmission Line (together known as “NECEC”). Exh. Joint Testimony of Waltman/Brennan/Furino, at 8. Additionally, the EDCs seek to collect annual remuneration equal to 2.75 per cent of the annual payments under the Proposed PPAs and TSAs. *Id*., at 9, 45.

The AGO respectfully requests that the Department:

1. Reject the EDCs’ request for annual remuneration of 2.75 per cent because, beyond mere conjecture, the EDCs have failed to provide quantitative support for their remuneration request;
2. Require the Proposed PPAs to be amended to require that the hydroelectric generation being procured is incremental to the historical average deliveries of hydroelectric generation into New England; and
3. Direct the EDCs to make certain improvements to the evaluation process for bids submitted under Green Communities Act (“GCA”) procurements concerning the: (a) prioritization of high ranking Stage 2 projects in Stage 3 portfolio development; (b) scaling approach used in the bid scoring; (c) Global Warming Solutions Act (“GWSA”) metric; (d) qualitative evaluation scoring; (e) separation of evaluation team members from bidding team members; and (f) disclosure of maximum potential remuneration costs to ratepayers.

II. BACKGROUND

Section 83D directs the EDCs to jointly and competitively solicit proposals from clean energy generation resources for cost-effective, long-term contracts for generation and any associated environmental attributes and/or RECs equal to an annual amount of 9,450,000 MWh (*i.e*., 9.45 terawatt hours (“TWh”)) of aggregate nameplate capacity by December 31, 2022. Section 83D(b). The Proposed PPAs and TSAs, which are subject to Department review and approval, shall be approved by the Department upon a finding that the Proposed PPAs and TSAs are “a cost-effective mechanism for procuring low cost renewable energy on a long-term basis.” Section 83D(e).

Here, the Proposed PPAs and TSAs are the product of a request for proposal ("RFP") that was approved by the Department on March 27, 2017. *Clean Energy Generation RFP*, D.P.U. 17-32, at 96 (2017). The EDCs, in concert with the Department of Energy Resources ("DOER"), issued the Department-approved RFP on March 29, 2017. Exh. JU-2. The RFP specified a three-stage process that the Evaluation Team would use to evaluate the bid proposals. [2] *Id*., at 10. In Stage One, the bid proposals were reviewed for minimum threshold and eligibility requirements. *Id*. Bid proposals that did not satisfy the Stage One dictates could be disqualified from further review by the Evaluation Team. *Id*., at 17. Bid proposals surviving Stage One were then subjected to Stage Two scrutiny, which evaluated the proposals using quantitative and qualitative criteria. *Id*., at 10. Finally, bid proposals surviving Stage Two[3] advanced to Stage Three for supplementary evaluation "to ensure selection of viable projects that provide low cost Clean Energy Generation with limited risk." *Id*.

At the end of Stage Three, the EDCs selected Northern Pass Transmission ("NPT") and NECEC "as the two top-ranked projects."[4] Exhs. Joint Testimony of Waltman/Brennan/Furino, at 32; JU-7; JU-8. Subsequently, the EDCs, being unable to reach consensus on a winning bid, advised the DOER of their stalemate. Exh. Joint Testimony of Waltman/Brennan/Furino, at 32. On January 25, 2018, the DOER, as part of its statutory role, selected NPT as the winning bid.[5] Exhs. Joint Testimony of Waltman/Brennan/Furino, at 32-33; IE Report, at 32.

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2 The Evaluation Team included members from the EDCs and the DOER. Exh. JU-2, at 5.

3 The Evaluation Team also created a combination of top-ranked projects from Stage Two for evaluation as portfolios in Stage Three. Exh. Joint Testimony of Waltman/Brennan/Furino, at 31; Tr. Vol. 1., at 66-67.

4 This statement appears correct in Exh. JU-8, but not in Exh. JU-7.

5 Pursuant to Section 83D(c), "If the distribution companies are unable to agree on a winning bid following a solicitation under this section, the matter shall be submitted to the department of energy resources which shall, in consultation with the independent evaluator,

On February 1, 2018, the New Hampshire Site Evaluation Committee denied NPT a Certificate of Site and Facility, finding that NPT had failed to demonstrate that the NPT "project would not unduly interfere with the orderly development of the region." Exhs. Joint Testimony of Waltman/Brennan/Furino, at 34; IE Report, at 34; DOER-1, at 3. Accordingly, the DOER decided that the EDCs should conduct concurrent contract negotiations with NPT and NECEC. Exhs. IE Report, at 35; Joint Testimony of Morin/Troy, at 10. Eventually, NECEC became the sole project in contract negotiations with the EDCs. Exhs. IE Report, at 36; Joint Testimony of Morin/Troy, at 11; Joint Testimony of Waltman/Brennan/Furino, at 35. On July 23, 2018, each EDC petitioned the Department for approval of long-term PPAs and TSAs, for the purchase of renewable energy output and RECs, and transmission delivery. Exh. Joint Testimony of Waltman/Brennan/Furino, at 8.

III. STANDARD OF REVIEW

Section 83D requires the EDCs to enter into jointly solicited cost-effective, long-term contracts to facilitate the financing of clean energy generation resources, subject to the review and approval of the Department. Accordingly, each EDC must show that its PPA and TSA facilitates the financing of the clean energy generation resource to which the PPA applies.[6]

In addition, Section 83D and 220 CMR § 24.05(1) dictate that the Department make certain findings to support approval of a clean energy generation PPA and TSA. Specifically, the Department must find that the clean energy generation resource: (1) provides enhanced electricity

issue a final, binding determination of the winning bid."

[6] To be an eligible clean energy generating source, the generation must: (1) provide firm service hydroelectric generation from hydroelectric generation alone; (2) be a new Class I RPS eligible resource that is firmed up with firm service hydroelectric generation; or (3) be a new Class I renewable portfolio standard eligible resource. Section 83B; 220 CMR § 24.02.

reliability; (2) contributes to reducing winter electricity price spikes; (3) is cost effective to Massachusetts electric ratepayers over the term of the PPA and TSA, taking into consideration potential economic and environmental benefits to the ratepayers; (4) avoids line loss and mitigates transmission costs to the extent possible and ensures that transmission cost overruns are not borne by ratepayers; (5) allows long-term PPAs and TSAs for clean energy generation resources to be paired with energy storage systems; (6) guarantees energy delivery in winter months; (7) adequately demonstrates project viability in a commercially reasonable timeframe; and (8) creates and fosters employment and economic development in the Commonwealth, where feasible. Section 83D; 200 CMR § 24.05(1). The Department also must consider the potential costs and benefits of the proposed contract and find that it is a cost-effective "mechanism for procuring low cost renewable energy on a long-term basis." 83D(e); 220 CMR § 24.05(1)(b).

Finally, when assessing the Proposed PPAs and TSAs, the Department considers whether the long-term contract is in the public interest.[7] The Department has held that, "in our review of long-term contracts for renewable energy generation under Section 83, the Department will also consider whether the contract is in the public interest." *Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid*, D.P.U. 10-54, at 27-28 (2010). That is, the Department, in reviewing long-term contracts for renewable energy generation, considers whether the contract is in the public interest according to the mandates of G.L. c. 164, § 94A and the Department's general regulatory and ratemaking obligations. *Id*., at 47.

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[7] Pursuant to G.L. c. 164, § 94A ("Section 94A"), an electric distribution company needs Department approval to enter into contracts to purchase electricity covering a period greater than one year. The Department has found Section 94A contracts must be consistent with the public interest to obtain Department approval. *See, e.g.*, *NStar Electric Company*, D.P.U. 07-64-A, at 58 (2008).

In examining whether Section 83D projects are in the public interest, the Department applies a four-prong test: (1) is the long-term contract an appropriate method to procure renewable energy when lower cost alternatives may be available; (2) are the pricing terms reasonable; (3) are the EDCs purchasing the correct amount of resources; and (4) are the bill impacts acceptable. *Id.*, at 66. The Department's public interest review is contract specific. *Long-Term Contracts for Renewable Energy*, D.P.U. 13-146/13-147/13-148/13-149, at 57 (2013); *Long-Term Contracts for Renewable Energy,* D.P.U. 17-117/17-118/17-119/17-120, at 12 (2018). *See also*, *Three-State Request for Proposals*, D.P.U. 15-84, at 22-23 (2015) (determinations regarding whether a contract is in the public interest are fact-based decisions on a case-by-case basis). The Department also considers whether the associated cost recovery method is in the public interest and will result in just and reasonable rates pursuant to Section 94A. D.P.U. 17-117/17-118/17-119, 17-120, at 14.

Under Section 83D, the Department has the authority to determine whether the EDCs should receive annual remuneration and, if so, how much. Section 83D(d)(3); *compare* D.P.U. 10-54, at 316; D.P.U. 13-146/13-147/13-148/13-149, at 63; D.P.U. 17-117/17-118/17-119/17-120, at 62 (statutes setting forth specific remuneration amounts). Section 83D directs the Department to promulgate regulations that shall, in part, "provide for an annual remuneration for the contracting distribution company *up to* 2.75 per cent of the annual payments under the contract to compensate the company for accepting the financial obligation of the long-term contract." Section 83D(d)(3) (emphasis added).

While Section 83D provides the Department with the authority to determine whether to allow remuneration, and if so, how much, it is silent regarding the standard the Department should use in making such a determination. It does provide, however, that the purpose of remuneration is to "compensate the company for accepting the financial obligation of the long-term contract."

See also, 220 CMR § 24.07(1). Thus, to determine the appropriateness of remuneration, the Department first must determine what, if any, financial obligations the EDCs accepted through the Proposed PPAs and TSAs.

As with any rate proposed rate increase, the Department also must consider whether a proposal results in just and reasonable rates. G.L. c. 164, § 94 ("Section 94"); *Investigation into Incentive Regulation*, D.P.U. 94-158, at 5, 42 (1995) (Department must ensure the "propriety" of a general rate increase); *Berkshire Gas Company*, D.P.U. 96-67, at 6 (1996) (rates must be just and reasonable).[8] To make this determination, the Department must evaluate customers' costs, including comparing the costs to customers of varying levels of remuneration. D.P.U. 17-117/17-118/17-119/17-120, at 63 ("Because remuneration is a component of understanding a contract's comprehensive cost to ratepayers, the Department finds that consistency in its application by the Distribution Companies in future long-term contract solicitations is appropriate.").

The Department relies on the evidentiary record in a proceeding to determine just and reasonableness. The party seeking the rate increase bears the burden of providing substantial evidence to allow the Department to do so. *See, e.g.*, *Fitchburg Gas and Electric Light Company*, D.T.E. 99-118, at 7, n.5 (2001) (the Company bears the burden of proving each and every element of its case by a preponderance of "such evidence as a reasonable mind might accept as adequate to support a conclusion."); G. L. c. 30A, § 11(6); P. LIACOS, HANDBOOK OF MASSACHUSETTS EVIDENCE, § 14.2 (7th ed. 1999).

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[8] Incentive proposals are also subject to the Section 94 standard of review requiring that rates be just and reasonable. D.P.U. 94-158, at 52. This includes demonstrating that the proposal is consistent with the Department's goal of providing a framework that ensures that the utilities it regulates provide safe, reliable, and least-cost service. *Id*.

IV. ARGUMENT

A. The Department Should Reject or Significantly Limit the EDCs' Remuneration Request

In their petitions, the EDCs request an annual remuneration of 2.75 per cent of the annual payments made pursuant to the Proposed PPAs and TSAs, which, if granted, will costs ratepayers [redacted] Exhs. Joint Testimony of Waltman/Brennan/Furino, at 9, 45; DPU-1-1, Att. [redacted] Despite such a lavish request, the EDCs fail to provide evidence quantifying their financial obligations arising from the Proposed PPAs and TSAs via calculations of either historic or estimated impacts. Tr. Vol. 1, at 110-117. Nor do the EDCs demonstrate that the collection of annual remuneration will result in just and reasonable rates.

Instead, the EDCs argue that they cannot calculate these costs, even though credit rating agencies offer an established methodology for doing so. Exh. AG-VM-1, at 24-25, 28; Tr. Vol 3., at 413-415. AGO witness Musco used such a methodology, the Standard and Poor's ("S&P") method, and found that the Proposed PPAs and TSAs will have little to no impact on the EDCs' financial wherewithal and/or access to capital. Exh. AG-VM-1, at 27. Thus, the EDCs' financial obligation under the Proposed PPAs and TSAs would be zero or close to zero. Exhs. AG-VM-1, at 27; AG-VM-Rebuttal-1, at 4.

1. Unlike Previous Section 83 PPA Reviews, the Department Now Has Discretion to Deny Remuneration

In drafting Section 83D, the Legislature specifically chose not to guarantee the EDCs any remuneration or require a specific remuneration amount as the Legislature had previously provided in Sections 83 (4 per cent) and 83A (2.75 per cent). Rather, in Section 83D, the Legislature granted the Department discretion to determine whether to allow remuneration, and if so, how much to allow. The only requirement the Legislature imposed is that the Department may not set a remuneration higher than 2.75 per cent. Section 83D(d)(3).

2. The EDCs Fail to Demonstrate the Need for Remuneration or Provide Sufficient Record Evidence for the Department to Determine the Propriety of the Proposed Remuneration Rate

Section 83D provides that the purpose of remuneration is to "compensate the company for accepting the financial obligation of the long-term contract." *See also,* 220 CMR § 24.07(1). The EDCs carry the burden to provide the Department with the evidence detailing the costs each company will incur from accepting the financial obligation of the Proposed PPAs and TSAs. *See, e.g.,* D.P.U. 94-158, at 52; D.T.E. 99-118, at 7, n.5; G. L. c. 30A, § 11(6). Here, the EDCs have not met their burden. The Legislature tied the determination and potential need for remuneration to the EDCs' *financial obligations* related to the Proposed PPAs and TSAs.[9] Therefore, in order make a determination regarding the appropriateness of remuneration, the Department must first determine what, if any, financial obligations the EDCs accepted through the Proposed PPAs and TSAs. The EDCs have provided no quantitative support for their remuneration request of 2.75 per cent nor have the EDCs attempted to quantify the financial obligations they will incur from the Proposed PPAs and TSAs or have incurred from other PPAs they have executed.

The only claim put forth by the EDCs centers on a potential financial obligation that *may* arise because the Proposed PPAs and TSAs may not be immediately recoverable from ratepayers. This lag, the EDCs predict, *might* have a negative impact on their cash flow and short-term borrowing rates. Exh. EDC-RBH-GET-1, at 43; Tr. Vol. 1, at 109-110, 122, 126-127. In fact, the EDCs acknowledge that they have not attempted to quantify the amount of such costs under the

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[9] While the overall mandate of Section 83D calls for a cost-effective contract for ratepayers, and a separate clause speaks to the impacts of a *proposal* on a company's balance sheet (an EDC can decline a "proposal if the proposal's terms and conditions … would place an unreasonable burden on the distribution company's balance sheet" Section 83D(c)), the clause in paragraph (d) stands alone with respect to the treatment of and considerations for remuneration.

Proposed PPAs and TSAs. Tr. Vol. 1, at 110-116. Concurrently, the EDCs acknowledge that they have not suffered any adverse impacts associated with their Section 83 and Section 83A long-term contracts. Tr. Vol. 1, at 79-80, 92-94, Exh. RR-AG-1, at 1.

The EDCs argue that the lag between making payments under the Proposed PPAs and collecting reimbursement under the Long-Term Renewable Contract Adjustment Mechanism ("LTRCA") *could* result in higher short-term borrowing costs. Exh. EDC-RBH-GET-1, at 37, 43; Tr. Vol. 1, at 37, 43. Yet, the LTRCA provides for the timely recovery of PPA and TSA costs. Exh. JU-12 A-C. Indeed, the LTRCA estimates the costs of the PPAs and TSAs in advance and collects those costs from ratepayers throughout the year. *See, e.g.*, Exh. JU-12 Eversource, at 2 ("LTRCA = The estimated long-term renewable contract and transmission service agreement expenditures plus remuneration for the Year"). That is, the EDCs do not need to wait an entire year to file a reconciliation mechanism or to file a rate case to recover most of the costs of the PPAs and TSAs because those funds flow to the company throughout the year. Under-recovery will be recovered either as part of the past period reconciliation amount in the next year's LTRCA or through arrearage recovery through general ratemaking. Exh. JU-12. Indeed, the EDCs admit that the LTRCA provides sufficient cost recovery of the contracts. Tr. Vol 1, at 120.

3. <u>Credit Rating Agency Methodologies Support a Remuneration at or Near Zero.</u>

The only quantitative evidence in the record suggests that, because the financial obligations under the Proposed PPAs and TSAs rest with the ratepayers, and not with the EDCs, remuneration should be minimal, at best. As explained by AGO witness Musco, the credit rating agencies offer a quantitative approach to estimating what financial obligations, if any, the EDCs will incur by executing the PPAs. For instance, the S&P method seeks to calculate the net present value of the fixed capacity payments under a PPA and reduce that value amount by a risk factor, which is intended to determine the risk of cost recovery for an EDC. Exhs. AG-VM-1, at 24-25; EDC-AGO-1-8, Att. 1, at 12-13. In determining the appropriate risk factor to assign to a PPA, S&P focuses on two factors: (1) is there a legislatively-created cost-recovery mechanism; and (2) does the EDC act as an intermediary between suppliers and customers rather than a generator. Exh. AG-VM-1, at 25-27.

Despite the EDCs' contention that the S&P methodology and analysis of imputed debt is "ill-suited" in determining GCA remuneration (Exh. EDC-RBH-GET-1, at 6), the S&P method is a detailed, predictable, and measurable approach that S&P uses in its credit assessments of utilities that, like the EDCs, are parties to PPAs. Tr. Vol. 3, at 422-423.[10] The application of the method itself is not rare—it is S&P's published methodology for all PPAs. *Id*. What is rare are utility requests for remuneration beyond actual costs and investments. Tr. Vol. 3, at 413-414. S&P's methodology has been used by utilities, and relied upon by regulators, in those rare instances. Tr. Vol. 3, at 419. The Hawaiian Electric Company ("HECO") effectively utilized the S&P method for determining financial risk to determine a metric to fairly evaluate utility-owned projects and third-party projects bidding into the same RFP. Exh. AG-VM-Rebuttal-1, at 5; Tr. Vol. 3, at 414, 427-428. There, the Hawaii Public Utilities Commission was able to review a showing from HECO of potential harm and make determinations based on the S&P method. Tr. Vol. 3, at 414.[11]

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10 Alternatively, the Department could look to Moody's Investor Service ("Moody's") and/or Fitch Ratings ("Fitch"), but neither agency provides the same level of detail as S&P. Nevertheless, Moody's explicitly treats PPAs with guaranteed cost recovery like those at issue here and applies no risk to the utility. Exhs. AG-VM-1, at 28-29; EDC-AGO-1-8, Att. 3, at 47; DPU-AG 1-4.

11 In jurisdictions where discretionary remuneration has been authorized, the public utility commission having discretion to grant a remuneration request denied all such requests (*i.e.*, Oklahoma, Oregon, Hawaii). The EDCs point to Rhode Island and Virginia as regulatory environments favorable to remuneration requests. Exhs. AGO 1-7; DPU 4-8. Neither state, however, provides for a discretionary remuneration like the one at issue here. Rhode Island provides a statutorily-guaranteed remuneration and the Commonwealth of Virginia

Application of the S&P methodology here shows that the EDCs' financial obligation would be "zero or close to zero for the PPAs at issue in this proceeding."[12] *Id*., at 27. In addition, because the EDCs are barred from owning and operating generation, the S&P methodology would likely apply a very low risk factor. Exh. AG-VM-1, at 25-26. Mr. Musco further notes "Moody's would likely view these PPAs as 'pass through' operating costs for the EDCs, thus imposing 'no risk' on the EDCs." Exh. AG-VM-1, at 29. Stated simply, the EDCs seek to "recover" costs that are non-existent or are very small.

4. The EDCs' Non-Quantitative Justifications Do Not Support Their Remuneration Request.

The EDCs make several non-quantitative arguments in support of their 2.75 per cent remuneration request. As addressed further below, none of these arguments provide evidence upon which the Department can rely to approve the EDCs' request.

First, the EDCs argue that because they receive 2.75 per cent remuneration for other long-term contracts, the Department should award them the same remuneration here. Exh. EDC-RBH-GET-1, at 67. This argument fails to acknowledge that the Legislature specifically changed the remuneration provision in Section 83D so that remuneration is not automatic but rather must be justified by the EDCs.

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provides enhanced returns for electric utility investments rather than for third-party PPAs and purchased power costs. Exh. AG-VM-1, at 43-44. Further, in Connecticut, where Eversource faces similar contracting schemes and size to Section 83D, no remuneration is provided. Tr. Vol. 1, at 108.

[12] Similarly, Moody's methodology explicitly treats PPAs with guaranteed cost recovery like those here, to apply no risk to the utility. Exhs. AG-VM-1, at 28-29; EDC-AGO-1-8, Att. 3, at 47.

Second, the EDCs argue that the Department will create an uncertain regulatory environment if it does not authorize 2.75 per cent. *Id*., at 68; Tr. Vol. 1, at 88, 109-110. This argument ignores the fact that when the remuneration guarantee of 4 per cent in Section 83 changed to 2.75 per cent under Section 83A neither the EDCs nor the Department's reputation suffered any known or measurable harm. Tr. Vol 1., at 93. Nor has the progression of remuneration through the various iterations of GCA clean energy soliciting requirements led to undue regulatory uncertainty. *Id*., at 91-94.

Third, the EDCs argue that remuneration is necessary because the financial markets will penalize the Distribution Companies without it.[13] Exh. EDC-RBH-GET-1, at 68; Tr. Vol. 1, at 88, 111-113. The EDCs warn that the cumulative commitment of the GCA PPAs (*i.e.,* Sections 83, 83A, 83C, and 83D procurements) could impact the financial positions and credit profiles of the Distribution Companies. Joint Testimony of Waltman/Brennan/Furino, at 48.

While recognizing that remuneration is at the discretion of the Department, the EDCs postulate negative impacts to their financial position from remuneration below 2.75 per cent by the financial community, including ratings agencies.[14] Tr. Vol. 1, at 75. Despite these concerns, the EDCs took no steps to engage the financial community or credit rating agencies to bolster (or dismiss) their contentions, or as a proactive step during contract negotiations, or through the associated tariff to mitigate such perceived impacts. Section 83D was signed into law in August of 2016. Yet, the EDCs have produced no evidence of negative reactions from the rating agencies.

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[13] In support of their remuneration request, the EDCs claim that they should be entitled to a return on the capital that is being invested. Exh. EDC-RBH-GET-1, at 19. The EDCs, however, will not be investing capital, therefore, a return on equity is not appropriate.

[14] The EDCs presuppose that anything less than 2.75 per cent remuneration is without "justification" and will "be extremely detrimental to the whole regulatory-compact process." Tr. Vol. 2, at 256-257.

Tr. Vol. 1, at 91-94. Moreover, the EDCs indicate that there has been no direct contact from or to any ratings agency regarding the fears of Section 83D or the potential future treatment of such contracts with respect to analysis of a utility's financial health. *Id.*, at 87. In part, this appears to be grounded in a fear of getting a cautionary opinion. *Id.*, at 88, 99; Exh. RR-AG-1. The risk of seeking an opinion here runs both ways. A signal from the ratings agencies that the Proposed PPAs and TSAs would likely diminish the EDCs financial profiles would support the EDCs' request for remuneration; while the opposite signal (*i.e.*, no effect on the EDCs financial health) would undercut the EDCs' professed need for remuneration.

The ratings agencies likely have followed the enactment of Section 83D as well as the events surrounding the eventual selection of NECEC for the purchase of 9.55 TWh of hydroelectricity generation to be delivered into New England; including the EDCs' petitions for approval of these long-term contracts. *Id*., at 101-104. Accordingly, the EDCs' opinions concerning remuneration are already known to the public and the ratings agencies.[15] And yet, the only publicly known change in ratings agency treatment of power purchase agreements like the ones under consideration here is via the development of S&P's methodology in 2013 (updated in 2018, with no changes to the power purchase adjustment). *See* Exh. AG-1-8, Att. 1.

Further, the EDCs have failed to provide any evidence, either in credit rating reports specific to the EDCs or in general credit rating agency documents, that shows that remuneration (*i.e.*, a de facto return on purchased power) is integral to a credit-supportive regulatory environment. Exhs. AG-VM-1, at 17; AG 1-14.[16] Admittedly, the EDCs fared no worse in the

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15 *See* Tr. Vol. 1, at 87 ("I'd be cautious to make such inquiries, because I wouldn't want them to think we're worried and point out that they should be worried.").

16 While it appears that S&P may have raised questions about the impact of potential GCA contracts on NSTAR prior to the passage of the GCA in 2008 and again prior to discussions with Cape Wind in 2012, the calls and concern from S&P appear to have ceased for now.

financial community when the remuneration rate dropped from 4 per cent under Section 83 to 2.75 per cent under Section 83A. Tr. Vol. 1, at 93. Further, the EDCs acknowledge that there is no credit exposure when legislative authority provides for pass through costs and that the credit rating agencies have not imputed any debt related to the GCA contracts. Tr. Vol. 3, at 421, 423, referring to *Distribution Companies Petition for Approval of Section 83C PPAs*, D.P.U. 18-76/18-77/18-78, Tr. Vol. 1, at 26, 30 and Exh. ES-JMM-1, at 10. In fact, the full and timely cost recovery of GCA PPA costs remains with Section 83D, providing that the ratepayers, and not the EDCs, are ultimately responsible for the $22 billion financial obligation associated with the Sections 83, 83A, 83C and 83D procurements. Exh. DPU-4-9.

Fourth, the EDCs argue that the application of the S&P method (or the treatments by Moody's or Fitch), is too narrow to serve as the sole focus for determining remuneration. Exh. ES-RBH-GET, at 71. Importantly, the EDCs agree that the S&P method is both traditionally used and demonstrates that the Proposed PPAs and TSAs expose the EDCs to no credit risk. Tr. Vol. 3, at 421, 423. Moreover, even though the EDCs call for a broader outlook, which includes review of the risks to cash flow and regulatory change, the EDCs have failed to substantiate such claims.

Fifth, the EDCs assert that since the net benefits provided to customers through the Proposed PPAs and TSAs outweigh the amount of remuneration requested, their request for remuneration is aptly justified and reasonable. Exh. EDC-RBH-GET-1, at 8-9, 48, 51. Moreover, the EDCs maintain that Section 83D ties the benefits of the Proposed PPAs and TSAs "imposed on the Companies' balance sheets" to the remuneration rate. *Id.*, at 13. This strained argument, however, misapplies the statutory language and intent of Section 83D. Pursuant to Section 83D,

D.P.U. 18-76/18-77/18-78, Tr. Vol. 1, at 42, 106. Subsequent to those calls, S&P updated its methodology for determining the financial risk analysis associated with PPAs as detailed above. D.P.U. 18-76/18-77/18-78, Exh. EDC-AGO-1-8, Att. 1, at 12-13.

EDCs are accorded an opportunity for remuneration to compensate the EDC for the financial obligation incurred by accepting the Proposed PPAs and TSAs. Section 83D(d)(3). Although Section 83D strives to obtain the benefits of clean energy generation for the Commonwealth, those benefits are not linked to the Department's determination of remuneration. Remuneration is not awarded to the EDCs in exchange for some of the benefits provided to ratepayers. The EDCs' efforts to stake a claim over a portion of those ratepayer benefits flies in the face of the separation of distribution service and generation ownership in the Commonwealth[17], and therefore, is not just and reasonable.[18]

Here, the EDCs perceived entitlement to a portion of ratepayer benefits is based on two concepts embedded in Section 83D. Exh. EDC-RBH-GET-1, at 18-19. First, Section 83D requires any *proposal* under consideration and contract to demonstrate benefits for selection and Department approval.[19] Second, Section 83D allows the EDCs to take reasonable actions in structuring resulting contracts to prevent balance sheet impacts. Section 83D(c). These provisions, however, speak to the development of the proposal and the contract, respectively, not to the determination of remuneration.

The EDCs' argument that the benefits from these Section 83D contracts should somehow flow to the EDCs and not to the ratepayers, who are paying for the generation, is outlandish.

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17 In Massachusetts, the Electric Restructuring Act provided for the "transition from regulation to competition in the generation sector," which would "consist[] of the unbundling of prices and services and the functional separation of generation services from transmission and distribution services." G.L. c. 164, § 1(m); *see also id.* §§ 1(g), 1(k), 1(l), 192, 193.

18 As the Oklahoma PUC noted, this type of request is contrary to traditional utility rate making. Exh. EDC-AGO-1-21, Att. 1, at 9-10.

19 *See,* Section 83D(d)(5). The Department shall "require that the clean energy resources to be used by a developer under the proposal meet the following criteria…"

Moreover, proposing that remuneration either represents a cut of those benefits or is quantified through calculating those benefits does not correlate with the clear statutory directive that remuneration is determined based on the EDCs' financial obligations. The calculation of ratepayer benefits offered here may be a helpful tool in determining the cost-effectiveness of these Proposed PPAs and TSAs pursuant to Section 83D, but that calculation has no place in determining the EDCs' remuneration rate.

B. The Proposed PPAs Should Be Amended to Require Deliveries to Be Fully Incremental

The 83D RFP solicited *incremental* hydroelectric generation so that the contract energy being solicited would provide a net increase in energy deliveries, relative to historical average deliveries to New England. *See* Exh. JU-2, at 5. The NECEC Hydro bid offered contract energy that would be incremental as defined by the RFP.[20] Draft Power Purchase Agreement, at 7 (May 12, 2017); Section 83D Request for Proposal Application Form, NECEC RFP Response (HRE), [redacted]. The NECEC Hydro bid was then evaluated assuming that the contract energy would be incremental to historical average deliveries, and it was selected on the basis of this evaluation. Tr. Vol. 1, at 182. However, the Proposed PPAs do not incorporate this requirement that the contract energy be incremental to historical average deliveries. Rather, the Proposed PPA requirements regarding incrementality, as manifested in their Exhibit H, are substantially more lenient. Exh. JU-3-A, Exhibit H; Exh. JU-3-B, Exhibit H; Exh. JU-3-C, Exhibit H. The lax requirements of the Proposed PPAs undermine the original intent and purpose of the solicitation. This should and can be remedied, as described below, by amending

[20] That is, the bid maintained the relevant language of the form PPA that had accompanied the RFP.

the Proposed PPAs to restore the requirement that contract energy be incremental to historical deliveries.

1. The Proposed PPAs do not Require Deliveries to be Incremental, in Contrast with the Terms Solicited by the RFP, Offered in the Bid, and Assumed in Evaluation and Selection.

The goal of procuring incremental clean energy was made clear throughout the solicitation process in the stated purpose of the RFP, the eligibility requirements in the RFP, and the Draft PPA. The first section of the RFP ("Section 1.1 Purpose of the Request for Proposal") states that the EDCs and the DOER are soliciting proposals for "incremental Clean Energy Generation" and Section 2.2.1.3 ("Eligible Bid Categories") defines two types of incremental generation: (1) Incremental Hydroelectric Generation ("Incremental Hydro") and (2) New Class 1 Renewable Portfolio Standard Eligible Resources.[21] The RFP defined Incremental Hydro as:

> Firm Service Hydroelectric Generation that represents a net increase in MWh per year of hydroelectric generation from the bidder and/or affiliate as compared to the 3 year historical average and/or otherwise expected delivery of hydroelectric generation from the bidder and/or affiliate within or into the New England Control Area.

Exh. JU-2, at 5.

In the RFP submission instructions, the RFP requires bidders to explain why hydro proposals qualify as incremental (Appendix B Section 4.1) as well as provide documentation that the delivery plan meets the definition of "Incremental Hydroelectric Generation" (Appendix B Section 4.2). *Id.*, at 55. Further, the Draft PPA, included as an attachment to the RFP, adopts the definition of Incremental Hydroelectric Generation from the RFP, even specifying which three

[21] The New Class I Renewable Portfolio Standard Eligible Resources includes new generators, which are, by definition, incremental to the system and increases from existing generators that "represent the net increase from incremental new generating capacity." Exh. JU-2, at 6.

years should be used to establish historical average deliveries for the purpose of defining Incremental Hydro. Draft Power Purchase Agreement, at 7 (May 12, 2017). In its proposal, NECEC (through Hydro Renewable Energy's ("HRE") separate submission), indicated that its bid met the definition of Incremental Hydroelectric Generation (Exh. NECEC RFP Response (HRE)_Confidential, at 16-19) and maintained the model PPA's language with regard to defining Incremental Hydro. Section 83D Request for Proposal Application Form, NECEC RFP Response (HRE)_Confidential, Att. 15.1.1 Form PPA-Mark-Up-Confidential, at 13.

The Proposed PPAs operationalized the requirement for Incremental Hydro with the provision for delivery of two types of energy: (1) the 9.55 TWh of Guaranteed Qualified Clean Energy ("Contract Energy"), and (2) Baseline Hydroelectric Generation Imports ("Baseline Hydro"), which is all other hydro energy delivered to New England from the bidder or affiliate, excluding the Contract Energy.[22] Following the RFP language, the Contract Energy under the Proposed PPA is the "Incremental Hydro." Exh. JU-3-A at 7; Exh. JU-3-B at 7; Exh. JU-3-C at 7. A minimum quantity of delivered Baseline Hydro ("Minimum Baseline Hydro") sets the reference point on top of which the Contract Energy will be considered incremental. The RFP defines this baseline as the "3 year historical average and/or otherwise expected delivery."[23] Exh. JU-2, at. 5. In its bid, HRE indicated that the 3-year historical average of 2014-2016 imports to New England was 14.8 TWh. Exhs. NECEC RFP Response (HRE)_Confidential, at 19; NEER 1-8. Other than retaining the "and/or otherwise expected delivery" phrase in the definition of

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22 The Proposed PPAs use slightly different terminology to refer to the same concept. The National Grid Proposed PPA uses the term "Baseline Hydro Generation Imports." Exh. JU-3-B, at 8. The Eversource and Unitil Proposed PPAs refer to "Baseline Hydroelectric Generation." Exhs. JU-3-A, at 86; JU-3-C, at 84.

23 The Draft PPA that accompanied the RFP incorporated similar language, further specifying that the 3-year historical reference period should be 2014-2016.

Incremental Hydro, the bid made no mention of this concept, and in particular, did not suggest that "otherwise expected delivery" might differ meaningfully from historical average deliveries.[24] Exh. NECEC RFP Response (HRE)_Confidential, Att. 15.1.1-Form PPA-Mark-Up-Confidential, at 13. Thus, a fully incremental PPA would reflect total deliveries of 24.35 TWh of deliveries (9.55 TWh of Contract Energy plus 14.8 TWh of Baseline Hydro).

However, of the 9.55 TWh of Contract Energy resulting from this solicitation, the Proposed PPAs require 0 per cent (*i.e.*, for Eversource and Unitil),[25] to at most 44 per cent (*i.e.*, for National Grid) of the Contract Energy to be incremental (*i.e.*, above the historical average of 14.8 TWh).[26] As explained by AGO witness Murphy, the Minimum Baseline Hydro requirements in the Eversource and Unitil Proposed PPAs would actually allow HQ to *decrease* its overall imports into New England, relative to the historical average established by the RFP, while receiving full payment under the Proposed PPAs. In other words, ratepayers would pay the full contract price (including payments under the Proposed TSA) for incremental energy, but receive no more energy than they had historically Exh. AG-DM, at 7-9. The 9.55 TWh of new Contract Energy plus the PPA requirement of 3.0 TWh of Minimum Baseline Hydro totals 12.55 TWh, substantially below the 14.8 TWh historical average.[27] Under the National Grid Proposed PPA, HQ could avoid penalties if HQ's total imports into New England increase by 4.2 TWh per year, which would

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[24] [redacted]. Section 83D Request for Proposal Application Form, NECEC RFP Response (HRE), at 19-20.

[25] The overall impact on flows is a -15% change. Exh. AG-DM, at 8.

[26] 4.2 TWh / 9.55 TWh x 100%= 44%. AGO Witness Murphy demonstrates that at most 4.2 TWh of the 9.55 TWh would be incremental based on the contracts as proposed. Exh. AG-DM, at 8.

[27] The Minimum Baseline Hydro in the Eversource and Unitil Proposed PPAs is itself 11.8 TWh below the incrementality standard of 14.8 TWh established in the RFP.

make only 44 per cent of the Contract Energy incremental, with the remaining 56 per cent just substituting for historical deliveries. Exh. AG-DM, at 8-9.

The EDCs offer several differing and sometimes conflicting explanations to justify the low Minimum Baseline Hydro requirements in the Proposed PPAs. Eversource and Unitil, for example, asserted that HQ has met the requirement for incrementality through its stated *capability* to deliver clean energy (*e.g.*, Exh. NEER 1-9), and that the *actual delivery* of incremental energy is not necessary. Of course, this interpretation does not honor the intent of the legislation or the RFP, which clearly anticipated that the clean energy delivered under the contract would be incremental to historical average deliveries. National Grid witness Brennan acknowledges this distinction and the need for an incentive to deliver:

> National Grid felt it important that, yes, the capability was important, but we also needed to some extent hold them to a standard to maintain their ability to deliver. It wasn't enough for us just to have the capability. We wanted to have some additional incentives in case they were needed to maintain that flow.

Tr. Vol. 2, at 214, lines 12-18.

In addition, the EDCs suggest that the baseline should exclude non-firm deliveries under the "and/or otherwise expected" clause of the RFP's definition of Incremental Hydro:

> …current deliveries may be non-firm and result from spot market trading decisions or may be under existing contracts that may not be renewed or extended. Thus, there are current deliveries that may not be appropriate for inclusion in the 'baseline' to which future deliveries are compared.

Exh. EDC-RB-1, at 17. But the RFP, the form PPA, and NECEC's bid made no mention of excluding non-firm, spot, or any other types of transactions when determining the historical average deliveries that would set the baseline. As AGO Witness Murphy pointed out, [redacted]

[redacted] such a redefinition of the baseline would render the concept of Incremental Hydro essentially meaningless. AG-DM-Rebuttal-1, at 5-6.

The EDCs later acknowledged that the Minimum Baseline parameters included in the Proposed PPAs do not reflect the "otherwise expected" flows from into New England from Hydro-Quebec. National Grid witness Brennan stated:

> …you started your question that we decided that the otherwise expected amount would be those numbers [the Minimum Baseline Hydro requirements]. I'd say that's not necessarily correct. These numbers reflect -- at least I'll speak for National Grid. It represents the number at which we would begin penalties and measurements of potential penalties. It's not necessarily reflective of what we expect or hope.

Tr. Vol. 1, at 24-26. Witnesses for Eversource and Unitil concurred with Brennan's response. Tr. Vol. 1, at 26.

Recasting the incrementality requirement as secondary to HQ's economic trading decisions, as would be implied if non-firm or spot deliveries were excluded from the historical average, does not reflect the goal of the solicitation. Rather than emphasize incrementality, the EDCs provide great deference to HQ's ability to pursue economic trading in other markets. Tr. Vol. 1, at 26-27; Tr. Vol., at 38-40. But the Proposed PPA payments to HQ are intended to compensate for energy that is incremental to the historical baseline. AG-DM-Rebuttal-1, at 22. Without specifying that the Contract Energy must be fully Incremental Hydro, HQ would be allowed to simply substitute at least most and perhaps all of the Contract Energy for historical deliveries. If HQ found it more profitable to divert historical generation to a different market, it would face no penalty under the Proposed PPAs. Unless the Proposed PPAs require that Contract Energy be Incremental Hydro, HQ has no incentive to maintain the Baseline Hydro deliveries that make the Contract Energy incremental and provide the benefits sought by the solicitation.[28]

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[28] The damages calculations in Exhibit H of the Proposed PPAs can and should amended to

Further, the Proposed PPAs do not require materially more energy deliveries than the existing transmission system can accommodate. Exh. AG-DM-Rebuttal-1, at 18. The Eversource and Unitil contracts would require a total delivery of 12.55 TWh of hydroelectricity into New England,[29] an amount that can easily be imported over the existing transmission network and has been since at least 2014.[30] *Id.*, at 15. The total deliveries required by the National Grid Proposed PPA are 19.0 TWh, only slightly more than the 18.2 TWh that can be supported by the existing transmission interface, and the 17.9 TWh that was actually delivered in 2017.[31] Exhs. EDC-RB-5, at 2; AG-DM-Rebuttal-1, at 14. The 1.1 TWh difference between the total deliveries required by the stricter National Grid Proposed PPA and the actual amounts delivered in 2017 over the existing system would utilize only about a tenth of the NECEC transmission line's capacity.[32] In fact, if HQ were to actually deliver only 18.2 TWh in total under the PPA (*i.e.*, under-deliver the Minimum Baseline Hydro by 0.8 TWh), the damages incurred under Exhibit H of the Proposed PPAs for under-delivery of Baseline Hydro would be only about $4.6 million, which is slightly less than 1 per cent of HQ's total PPA revenues. Exh. AG-DM, at 11.

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incentivize incremental energy, as recommended here in the following section (IV.B.2). However, the potential for damages to be assessed does not mandate specific behavior. HQ would still be able to deliver less than the required amount of Baseline Hydro, and would have the incentive to do so if it could cover the calculated damages.

[29] 12.55 TWh = 9.55 TWh Contract Energy + 3.0 TWh Baseline Hydro

[30] HQ exported between [redacted] over 2014-2018 to New England. Exh. AG-DM-Rebuttal-1, at 15; Hydro-Québec Annual Report 2018, at 34; Hydro-Québec Annual Report 2017, at 11.

[31] Hydro-Québec's 2017 annual report states that exports to New England were 52% of the 34.4 TWh of exports. Hydro-Québec Annual Report 2017, at 11.

[32] 1,100,000 MWh / 8,760 hours per year = 126 MW vs NECEC transmission capability of 1,200 MW.

Further, the interpretation of Incremental Hydro as being fully incremental to the historical average is necessary to ensure consistency with the requirements for renewable bids, which were required to provide Contract Energy that is fully incremental. In fact, renewable bids were required to meet a stricter standard in this respect, since they were required to be *new* resources, which necessarily provide incremental energy. Hydroelectric bids could offer energy from existing resources, if their energy was incremental to New England.

The benefits of the NECEC Hydro bid are premised on the Contract Energy being incremental to historical average deliveries. In its quantitative evaluation, Tabors Caramanis and Rudkevich ("TCR") assumed full incrementality in evaluating the bid. *See,* Tr. Vol. 1, at 180-182. TCR did not evaluate deliveries based on the Exhibit H requirements in the Proposed PPAs (which had not been drafted at the time of evaluation). Tr. Vol. 1, at 180-181. As illustrated by AGO witness Murphy, based on average emission rates of Massachusetts imports, the greenhouse gas ("GHG") reductions attributable to Massachusetts would be lower (*i.e.,* emissions attributable to Massachusetts would be higher) if HQ delivered only what is required by the Proposed PPAs, relative to the case if the Contract Energy was Incremental Hydro. Exh. AG-DM-Rebuttal-1, at 10-11.

Despite the fact that the core motivation for the clean energy generation solicitation was that Contract Energy would be incremental; that the RFP solicited incremental energy; that the NECEC Hydro bid offered incremental energy; and that NECEC's Hydro bid was evaluated assuming it was incremental, the EDCs appear to have treated the incrementality requirement as a bargaining chip in the contract negotiations. The EDCs have explicitly framed the incrementality requirements in Exhibit H of the Proposed PPAs as a facet of the contract negotiations. *See, e.g.*, Tr. Vol. 2, at 200, lines 2-18; Tr. Vol. 2, at 206-208; Tr. Vol. 2, at 208-211; Revised Independent

Evaluator Report (Redacted), at 51-53 (August 7, 2018). Rather than ensuring that the Proposed PPAs would provide Incremental Hydro, the Unitil and Eversource witnesses indicated that the negotiations settled on a number that was based on what HQ could provide except under force majeure conditions:

> I think we were looking for a volume that they [HQUS] could absolutely agree to. And I think if you look at the force majeure provision, literally they would have to be unavailable or unable to deliver for nearly half of a year before the force majeure provision would kick in.

Tr. Vol. 2, at 199. Despite Eversource witness Waltman's statement that the minimum Baseline Hydro amount was negotiated to provide "the most value for customers" (Tr. Vol. 2, at 198), he did not describe any benefits that customers would receive in exchange for the effectively sacrificing of the requirement that the Contract Energy be incremental and the related benefits that would bring for ratepayers. In fact, Eversource witness Waltman described the differences between the Proposed PPAs other than Exhibit H as "minor." Tr. Vol. 2, at 209.[33] Instead, the Eversource and Until negotiations and the resulting Proposed PPAs prioritized the utilities' ease of administration, which was cited repeatedly as a concern for the Distribution Companies. *See*, *e.g.*, Tr. Vol 2., at 198-199, 208-209. Prioritizing ease of contract administration over ensuring that the Contract Energy is incremental is inconsistent with the goals of a solicitation to acquire incremental clean energy.

2. <u>Recommended Changes to the Proposed PPAs to Provide Fully Incremental Hydro</u>

As written, the Proposed PPAs fail to achieve the goals of the Section 83D solicitation because they do not require the Contract Energy to be fully incremental. In reviewing the 83D

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[33] The differences between the three Proposed PPAs are enumerated in Exh. Joint Testimony of Waltman/Brennan/Furino, at 14-15.

RFP, the Department anticipated a vigorous review of "all phases of contract development and negotiation, and to the specific terms and conditions contained in the resulting PPA(s) in the context of the adjudication before the Department of individual long-term contracts for renewable energy." D.P.U. 17-32, at 19. The negotiations stemming from that RFP yielded Proposed PPA terms and conditions which fail to provide ratepayers with the promised historical average deliveries to make the contract energy truly incremental.

The Department has a relatively straightforward mechanism to correct these PPA deficiencies for ratepayers while recognizing the potential for varying hydrologic conditions faced by HQ in any given year. Indeed, the existing Proposed PPA language (particularly National Grid's Proposed PPA) provides a ready framework to require fully Incremental Hydro, while also providing mechanisms to address reasonable circumstances in which potential conditions may limit HQ's ability to deliver Baseline Hydro. Exh. JU-3-B, Exhibit H.

The Department should require Exhibit H of each of the Proposed PPAs to be amended to require a Minimum Baseline Hydro value of 14.8 TWh because this was the historical average solicited in the RFP, offered in the NECEC Hydro bid, and relied upon during bid evaluation and selection. This ensures that the 9.55 TWh of Contract Energy is all Incremental Hydro. With this amendment, the Contract Energy provided in the PPAs will match the Incremental Hydro solicited in the RFP and offered in the NECEC Hydro bid. This will ensure that Contract Energy does not simply substitute for historical energy deliveries, which would undermine efforts to increase clean energy deliveries and reduce GHG emissions.

Accordingly, using National Grid's Exhibit H as a model (its terms are closely aligned with the issues that might arise if the Minimum Baseline Hydro value is increased to require full incrementality), the new Section 1.b should substitute the historical average of 14.8 TWh for the

9.45 TWh initial value of the Proposed PPA for the Minimum Required Baseline Hydroelectric Generation Imports, with corresponding changes to the Eversource and Until PPAs.

Further, National Grid's Proposed PPA includes adjustments "A" through "F" to this initial Minimum Baseline Hydro value, and some adjustments may become more important as the Minimum Baseline Hydro requirement is amended to reflect the historical average. The concern around HQ's ability to generate historical levels of hydroelectric production, and thus hydroelectric exports, in each and every year is legitimate, being rooted in the natural variability in hydrologic conditions. In particular, adjustment factor "C" in Section 1.b of Exhibit H, adjusts for the total amount of HQ exports (which will be driven primarily by variable hydrologic conditions); this should be retained and applied from the beginning of the contract term rather than starting in year 11, as in the Proposed PPA. Exh. JU-3-B, at 92-93.

The remaining National Grid adjustments in Section 1.b necessitate different treatment. First, adjustment factor "A" reduces the Minimum Baseline Hydro to the extent on-peak prices in New England are below a specified threshold, initially $25/MWh, in some hours. This factor reduces the Minimum Baseline Hydro requirement (and thus the total energy HQ must deliver) for economic reasons only, unrelated to transmission availability or energy availability. HQ already has considerable flexibility regarding the particular timing with which it delivers both Contract Energy and Baseline Hydro. This flexibility will allow HQ to avoid delivering in low-priced hours if it so chooses; a further reduction in the overall energy delivery requirement does not respect the need for Incremental Hydro and is not warranted. Thus, the Department should strike adjustment factor "A".

The other adjustment factors in Section 1.b of National Grid Exhibit H, adjustments "B," "D," "E" and "F," could be maintained in recognition of previous negations. Tr. Vol. 2, at 205-

207. To the extent simplicity of contract administration is important to Eversource and Unitil (*e.g.*, Tr. Vol. 2, at 208-209), Adjustments "B," "D," "E," and "F" might be utilized as negotiating points. The five-year averaging performed under Section 3 of Exhibit H (Exh. JU-3-B) for purposes of determining the damage payment is not necessary, given that adjustment factor "C" adjusts the Minimum Baseline to account for variability in energy availability, but not problematic.

In addition to establishing the Minimum Baseline threshold properly at 14.8 TWh, the calculation of Baseline Hydroelectric Generation Imports Shortfall Damages[34] should be calibrated to reflect how much of the NECEC transmission link is needed, given how much Incremental Hydro is actually delivered. To do this, to the extent Contract Energy is not fully incremental (*i.e.*, to the extent Baseline Hydro falls short of the Minimum Baseline), ratepayers should recover from HQ a share of the TSA payment as damages. This structure already exists in the Proposed PPAs; only the parameter values need amending.

As described by AGO Witness Murphy, the Minimum Baseline should be set to the historical average of 14.8 TWh per year. Damages would be zero if HQ delivered fully Incremental Hydro (i.e., 14.8 TWh of Baseline Hydro in addition to 9.55 TWh of Contract Energy, totaling 24.35 TWh). Exh. AG-DM-Rebuttal-1, at 20-21, Figure 3. In the other extreme, if Baseline Hydro deliveries were only 5.25 TWh, such that the total energy delivered (<u>including</u> Contract Energy) was just 14.8 TWh, then no incremental energy would have been delivered because the Contract Energy was a substitute for historical average energy.

The 14.8 TWh could easily be accommodated across existing transmission facilities as considerably more than this has been delivered in recent years. Exh. AG-DM-Rebuttal-1, at 14-

[34] Again, the three Proposed PPAs use different terminology, but are conceptually similar.

16; Hydro Quebec's 2018 Annual Report, at 34[35]. Baseline Shortfall Damages at this point should equal 100 per cent of the TSA payment, so that ratepayers would be reimbursed for the unneeded (in this instance) NECEC transmission capacity. Thus, the damages amount would reflect the cost of transmission capacity constructed but not needed, due to a shortfall below the Minimum Baseline. In terms of the parameters of Exhibit H for National Grid, this will simply require substituting 9.55 TWh, the required Clean Energy of the contract, in place of Minimum Required Baseline Hydroelectric Generation Imports, in the denominator of the formula described in Section 2 of Exhibit H. Exh. JU-3-B, at 94. A similar adjustment should be made to the Eversource and Until Proposed PPAs.

The progressive reductions to the damages given in the table in Section 3 of Exhibit H (*i.e.*, damages reduced to 80 per cent for the second 5-year period of the contract term, to 60 per cent for the third 5-year period, and 40 per cent for the last 5-year period) are unwarranted and simply reduce, over time, the incentive HQ would have for continuing to provide Incremental Hydro. Since shortfalls are no less problematic in later years, the PPAs should require fully incremental hydro for the duration of its term, without reducing the shortfall damages.

Thus, the necessary changes to the Proposed PPAs are relatively straightforward and easy to implement, with the key changes involving amendments to the parameter values. To restate, using the National Grid Exhibit H as a template, the Department should require the following changes:

- In Section 1.b of Exhibit H, substitute the 14.8 TWh historical average generation in place of the 9.45 TWh initial value (before adjustments) of the Minimum Required Baseline Hydroelectric Generation Imports;
- In Section 1.b:

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[35] Publicly available at http://www.hydroquebec.com/data/documents-donnees/pdf/annual-report.pdf.

  - Eliminate adjustment factor "A";
  - Apply adjustment factor "C" from the beginning of the contract term;

- In Section 2, substitute 9.55 TWh, the required Clean Energy of the contract, in place of the Minimum Required Baseline Hydroelectric Generation Imports, in the denominator of the formula;
- In Section 2:
  - Eliminate adjustment factor "A";
  - Apply adjustment factor "C" from the beginning of the contract term; and
  - Adjustment factors "B," "D," "E" and "F" can be retained or used as negotiating points; and
- In Section 3, eliminate the progressive reductions to the damages amount given in the table.

C. Improvements to the RFP Process for GCA Long-term Contracts

The AGO recommends that the Department require certain changes to the evaluation process undertaken by the EDCs and DOER in future procurements to incorporate lessons learned here. Because the EDC purchase commitments associated with the GCA clean energy generation procurements represent billions of ratepayer dollars, it is crucial that each evaluation process be as robust, nondiscriminatory, and competitive as possible. The Department is tasked under the GCA with reviewing any proposed RFP and considering amendments to that particular timetable and method of solicitation during their review. No other proceeding available at the Department more acutely highlights the faults in the evaluation process than during the PPA review by the Department and therefore presents the most opportune time to recommend improvements for future evaluations. Just as Department Orders following reviews of prior GCA PPAs included recommendations for future *evaluation process* improvements[36] (which are incorporated in the

[36] *See* D.P.U. 13-146/13-147/13-148/13-149, at 84-85 (Department expects the evaluation process to include written documentation of Stage 3, ensure all deposits and corporate approvals prior to filing petition); D.P.U. 17-117/17-118/17-119/17-120, at 74 (Department-drafted recommendations to increase clarity and efficiency of process).

EDCs' petition here)[37], so are Department requirements related to further modifications resulting from the Section 83D evaluation appropriate here.

Incorporating lessons learned from the Section 83D process to future evaluations of long-term contracting bids will help to ensure the best possible results for ratepayers. To that end, the AGO recommends that the Department implement the following changes to future GCA evaluations conducted by the EDCs and DOER because they are in the public interest: (1) establish clear rules for prioritizing high-ranking Stage 2 projects in Stage 3 portfolio development; (2) direct the EDCs to remedy the scaling approach used in bid scoring, which could improperly affect the relative weight given to qualitative and quantitative factors and potentially the ranking of bids; (3) require the GWSA metric be revised to directly reflect changes in GHG emissions; (4) separate bidding team members from evaluation team members; and (5) require the EDCs to disclose estimated maximum remuneration costs to ratepayers.

1. <u>Highest Ranking Projects After Stage 2 Should be Prioritized in Stage 3 Portfolio Development</u>

The RFP provided for a three-stage evaluation process followed by project selection. *See* Exh. JU-2, at 10, 17-44. The first stage evaluated bids against the RFP threshold requirements. *Id.*, at 17. Bids that met the threshold requirements were carried to Stage 2 for evaluation on both quantitative and qualitative dimensions. *Id.* As made clear in the RFP, only a subset of bids from Stage 2 would be evaluated in Stage 3. *Id.*, at 41. Stage 3 allowed for the development and evaluation of portfolios created from multiple bids. *Id.* To determine the individual bids that would be considered for inclusion in portfolios, the RFP provides three metrics: 1) the rank order

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[37] See Exhs. Joint Testimony of Waltman/Brennan/Furino, at 13, 31; JU-6, at 18; JU-7; JU-8.

of the bids at the end of the Stage 2 evaluation, 2) the cost effectiveness of the bids based on the Stage 2 quantitative evaluation, and 3) the total annual generation of the bids relative to the procurement target. *Id.*

The Evaluation Team did not consider a portfolio solely composed of the two top-ranked Stage 2 projects, despite that together they provided [redacted] of the total 83D energy target. Instead, it diluted the apparent value of these projects in Stage 3 by only evaluating them in portfolios which also contained [redacted] with [redacted] lower net direct benefits. Exh. JU-6, at 22, 24. By yoking the high performing Stage 2 projects to low scoring [redacted] projects, the Evaluation Team effectively removed from consideration what may have been one of, if not the, highest value portfolios. Exh. AG-DM, at 22. In any case, the failure to formally evaluate this promising portfolio made it impossible to trade off its better performance against its somewhat smaller size.

Although the Evaluation Team emphasized meeting the procurement targets in a single solicitation, the evaluation protocol did not prohibit the Evaluation Team from considering portfolios of less than the full 9.45 TWh. Exh. WP Support Tab F. In addition, section 83D explicitly allows the Evaluation Team to pursue multiple solicitations to meet the 9.45 TWh goal. Section 83D(b). Despite the ability to pursue multiple solicitations, the Evaluation Team stated that a portfolio of the highest-ranked projects from Stage 2 was too small for consideration and needed to be combined with additional bids. Exh. EDC-RB-1, at 68. The Evaluation Team, however, was unable to identify a minimum threshold for portfolio size or explain why other portfolios of less than the total solicitation goal of 9.45 TWh were evaluated. Tr. Vol. 1, at 67, 70-72; Tr. Vol. 3, at 468-469.

In justifying the failure to consider this portfolio, the Evaluation Team inappropriately dismissed the potential for subsequent 83D solicitations to procure high value projects. The Evaluation Team asserted that small projects in future solicitations would, at best, score similarly to those in this solicitation, effectively stating that the bids in the current 83D solicitation were representative of projects in all future solicitations could not be improved upon and may not be equaled.[38] Exh. AG-3-2; Tr. Vol. 3, at 465-466. As explained by AGO witness Murphy "the absence of evidence [of additional high scoring small projects] is not evidence of absence," and he provides an example of a high value of projects in another solicitation and the potential for future projects. Exh. AG-DM-Rebuttal-1, at 26-27.

To remedy this, future solicitations should not include a size threshold for portfolio selection, but should allow consideration of portfolios of high-ranking bids that may be somewhat smaller than the targeted in the solicitation, particularly where subsequent solicitations are an option. This would avoid diluting the value of promising projects in an attempt to achieve a pre-defined size expectation, and allow for an explicit trade-off between portfolio size and value. At the very least, if a size threshold is to be used for portfolio construction, it should be made explicit in advance of the evaluation process.

In retrospect, the Evaluation Team's apparent unwillingness to consider a "smaller" portfolio in Stage 3 of this solicitation stands in marked contrast to its willingness to accept the weak Minimum Baseline requirements of the Proposed PPAs in the contract negotiation phase. The Proposed PPAs would allow more than half of the contract energy to substitute for historical

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38 Eversource witness Waltman statement that "I guess it's not out of the realm of possibility that another solicitation could be competitive with this solicitation, but it is a risk," and appeared to reluctantly agree to the possibility of future solicitations procuring projects with similar value to the current solicitation. Tr., Vol. 2, at 246.

deliveries, which would result in just 4.2 TWh of incremental clean energy delivered to New England. Exh. AG-DM, at 8. In contrast, the portfolio consisting of the top two Stage 2 projects, which the Evaluation Team was unwilling to consider because it was too small, would have provided [redacted] of incremental clean energy. Exh. AG-DM, at 23, lines 3-6.

2. Scaling

In the current solicitation, the Evaluation Team assessed the quantitative aspects of a bid proposal, scaling the resulting values using a 75-point scale. Exh. JU-2, at 36. The bid proposal's scaled quantitative score was then added to the 25-point scale used to evaluate the qualitative aspects of the bid proposal. Exhs. JU-2, at 36; Revised Independent Evalatory Final 83D Report (redacted), at 11. This scaling approach meant that the value of a qualitative point, and thus the relative importance of qualitative vs. quantitative factors, was determined by the result of the quantitative scaling, which could not be known in advance. Exh. AG-DM, at 26-27. Thus, rather than the Evaluation Team *explicitly* valuing a qualitative point in dollar terms, the scaling approach *implicitly* assigns a dollar value in a way that could influence the ranking of proposals in ways the Evaluation Team did not intend or even understand. In this solicitation, quantitative and qualitative scores are negatively related among several of the higher-scoring proposals, with bids that scored high on quantitative measures having lower qualitative scores, and vice versa. *Id*., at 26. Because there was not a bid or portfolio that outperformed others on both quantitative and qualitative scoring (Exh. JU-6, at 20, 25), the relative weighting of qualitative and quantitative scores could have affected the final ranking of projects (in Stage 2) and portfolios (in Stage 3), and thus should be carefully considered. Exh. AG-DM, at 26, lines 8-13. While project selection does not appear to be particularly susceptible to differences in weighting or scaling in this solicitation, simply due to the particular bid scores involved, the scaling approach could easily have an impact in any future solicitation.

The AGO has previously recommended consideration of the methods to address these issues, such as assigning a dollar value to qualitative points or establishing where the qualitative value should be relative to the magnitude of the total quantitative benefits.[39] These approaches would provide several benefits, discussed previously by the AGO and repeated here:[40]

- Clear signals are conveyed to the bidders as to the value of the qualitative attribute (when combined with increased transparency to bidders regarding the qualitative scoring mechanism);
- Project scoring is independent of the pool of bids;
- The weighting of qualitative vs quantitative factors is explicitly considered by the Evaluation Team and is consistent with their judgment; and
- Provides additional transparency in qualitative scoring.

In future solicitations, the Evaluation Team should explicitly consider the relative weighting of qualitative and quantitative factors, rather than repeating the implicit weighting in the current scaling approach.

3. **The GWSA Metric Should Directly Reflect Changes in GHG Emissions, without Subtracting Off REC/CEC Quantity**

The GWSA metric as constructed and used in this solicitation does not accurately represent the GWSA contributions of the potential projects. The GWSA benefits were calculated as the dollar value of the GHG emissions decrease (relative to the Base Case defined by the Evaluation Team) reduced by the number of Renewable Energy Credits (RECs) or Clean Energy Credits (CECs) created by the project. Exh. JU-6, at 31. In future solicitations, the GWSA metric should reflect changes in GHG emissions, *without* netting off the number of RECs or Clean Energy

[39] D.P.U. 18-76/18-77/18-78 *Initial Brief of the Office of the Attorney General*, at 18.

[40] D.P.U. 18-76/18-77/18-78 *Initial Brief of the Office of the Attorney General*, at 19.

Credits generated by a project. While Eversource and Unitil, as well as the DOER, feel the current approach is accurate, National Grid has expressed the same concerns about this metric and proposes the same correction for it. Exh. RB-1, at 76-77.

The issues raised by AGO witness Murphy in this proceeding[41] and the AGO and witness Murphy in the previous proceeding related to the Section 83C solicitation[42] pertain to the construction of the GWSA metric and not to the Massachusetts greenhouse gas inventory itself. The evaluation approach used to compare projects in the solicitation determines the value of each project by calculating the *difference* between a scenario including that project and a Base Case that does not include the project. Since this evaluation approach already nets off the value of the Base Case (and the Base Case includes RPS and CES compliance), the project value calculated is already net of the value of RPS and CES compliance. Netting off the REC/CEC value a second time within the GWSA metric is unnecessary, and introduces an error.

As agreed by the DOER and the EDCs, the development of the GWSA metric is complex and relies upon detailed modeling assumptions. Tr. Vol. 3, at 499-505; Joint Testimony of Waltman/Brennan/Furino, at 27-28. The DPU should require that in future solicitations, the Evaluation Team address the issues raised but not resolved in this and the Section 83C proceedings. This includes how the evaluation protocols and quantitative modeling relate to and interact with the Massachusetts greenhouse gas inventory approach, and Renewable Portfolio Standard and Clean Energy Standard policies.

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[41] Exh. AG-DM at 27.

[42] D.P.U. 18-76/18-77/18-78 *Initial Brief of the Office of the Attorney General* at 23-24; . D.P.U. 18-76/18-77/18-78 Exh. AG-DM-1 at 16-19.

4. <u>Evaluation and Bidding Personnel Should Be Completely Separated</u>

Real or perceived, conflicts of interest in a solicitation can undermine the process and the outward appearance of fairness. Exh. AG-DM, at 23-25. Having entities on the Evaluation Team and Selection Team that are also bidders in the solicitation (either directly or through affiliates), creates an inherent conflict of interest and potentially introduces intentional or unintentional bias into the evaluation process. This conflict arose in this solicitation, since the three EDCs were part of the Evaluation Team, and two of them (National Grid and Eversource) were bid or were affiliated with bidders. The Independent Evaluator ("IE") documented multiple instances of an apparent bias by an EDC towards its bid:

> *Based on our observations, Eversource favored, or had the appearance of favoring, NPT in various stages of the evaluation and selection process, especially toward the end.* This included the deliberations with respect to the interest rate assumption in the quantitative evaluation and the qualitative evaluation with respect to several criteria, [redacted] This was also the case with respect to the Stage 3 and bid selection process, where Eversource focused on aspects of the evaluation, evaluation metrics and assumptions that supported selection of Northern Pass. It was perhaps even more apparent when Eversource sought to keep NPT in play for contract negotiations even after the required New Hampshire siting approval was denied, with a remote possibility for a prompt reversal in order for Northern Pass to be able to build the project anywhere near the timeframe proposed.

Revised Independent Evaluator Final 83D Report (Redacted), at 48-49 (emphasis added). In addition to this summary of apparent favoritism, the IE identified instances in Stage 2, where, for example, Eversource proposed that NPT receive higher qualitative scores for price firmness/risk, contract risk, and commercial operation date certainty tested the bounds of impartiality. Exh. Revised Independent Evaluator Final 83D Report (Redacted), at 27. Similarly, the IE identified instances in Stage 3, such as giving preference to projects that deliver earlier than others,[43]

[43] [redacted] and Eversource claimed that the evaluation "…did not give sufficient value to this attribute…" Revised Independent

proposing that a contingency cost be assessed for projects at an relatively early stage of development,[44] and arguing that NPV was a better metric of customer benefits than the Evaluation Team's agreed upon metric of $/MWh. [45] All of these call into question the Evaluation Team's objectivity.

Absent a legislative change, the EDCs likely will continue to bid into future solicitations they evaluate. Thus, there is a need to address potential conflicts of interest on an on-going basis. As one example, the perception of conflict of interest in this solicitation also affected the 2017 Section 83C solicitation, with Eversource attempting to withdraw from its role on the Evaluation Team.[46] One approach that is often used to minimize potential conflicts in competitive solicitations is to fully separate bidders from the evaluation team (*i.e.*, no organization or its affiliates could both bid in the solicitation and be involved in the evaluation of bids). While the current statutory construct appears to preclude such full separation in the Section 83D solicitations, the Department should take every action within its authority to restructure the process to address the conflict that inevitably arises when the EDCs are on both sides of the deal.

In addition, future RFPs should require that the IE be granted the ability to monitor contract negotiations with full and uninhibited access to bidder communications on negotiation and draft

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Evaluator Final 83D Report Redacted, at 30, 68 (August 7, 2018).

44 [redacted]. Eversource made the suggestion that a contingency cost should be assessed for projects with greater risk. WP Support Tab E Confidential, at 2-3. Revised Independent Evaluator Final 83D Report Redacted, at 30 (August 7, 2018).

45 Using the NPV benefit value, the NPT proposal had higher scores and ranked above the NECEC proposal; Eversource argued that the NPV metric was a better indicator of value than $/MWh. Revised Independent Evaluator Final 83D Report Redacted, at 29-31 (August 7, 2018).

46 D.P.U. 18-76/18-77/18-78 Independent Evaluator Final 83C Report Redacted, at 18 (August 3, 2018).

contracts. In this solicitation, the IE was not granted such access due to EDC objections. Revised Independent Evaluator Final 83D Report (Redacted), at 33, 40. If conflicts of interest had been an issue during the contract negotiation phase (i.e., if an EDC's or affiliate's bid had been selected), there would have been insufficient opportunity for the IE to document and present such issues for the Departments' consideration. As illustrated in in this solicitation, when EDCs are both the Evaluation Team and the bidders (directly or through affiliates), the potential for conflict of interest is not illusory.

5. Ratepayers Should Know the Cost of Remuneration

The Department should require the estimated cost of remuneration for the Proposed PPAs and TSAs here, and in all future GCA procurements, be disclosed to ratepayers. The EDC request for remuneration represents hundreds of millions of dollars in ratepayer costs, yet the potential maximum obligation they face is hidden.[47] The Department previously found inconsistencies in the application of remuneration to the analyses of contract costs of GCA PPAs and required the EDCs change its approach. D.P.U. 17-117/17-118/17-119/17-120, at 63. The AGO recommends the Department continue to improve the reporting and analyses of remuneration costs for ratepayers by clearly disclosing the maximum total costs of the EDCs request here and require the EDCs to do so in future *petitions* for GCA PPA review.

[47] While the precise calculation of the requested remuneration is provided in Exh. DPU 1-1, Att. 1 (Proposal Quant Nominal w_Renum, E41:AC41) (HSCI), a generic calculation of such costs can be calculated for the promised 9.55 TWh over twenty years using the requested 2.75% rate, the disclosed Price for Products in the Proposed PPA *(e.g.*, Exh. JU 3-A, at 75) and Unit Price in the Proposed TSA (Exh. JU 4-A, at 132). The calculation of renumeration does not concern the proprietary and competitively sensitive information of any proposals and therefore are likely to have been disclosed had the EDCs filed a redacted Exh. DPU 1-1, Att. 1 for the record.

V. CONCLUSION

Consistent with the recommendations detailed herein, the Office of the Attorney General respectfully requests that the Department, deny the requested remuneration, and direct the EDCs to make the Office of the Attorney General's recommended changes to the Proposed PPAs and any future clean or renewable energy long-term contract Request for Proposal.

Respectfully submitted,

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Dated: March 22, 2019

REDACTED

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

NSTAR Electric Company d/b/a Eversource Energy	)	**D.P.U. 18-64**
Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	)	**D.P.U. 18-65**
Fitchburg Gas and Electric Light Company d/b/a Unitil	)	**D.P.U. 18-66**

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing document to be served upon all parties of record in this proceeding in accordance with the requirements of 220 C.M.R. 1.05(1) (Department's Rules of Practice and Procedure). Dated at Boston this 22nd Day of March, 2019.

Respectfully submitted,

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