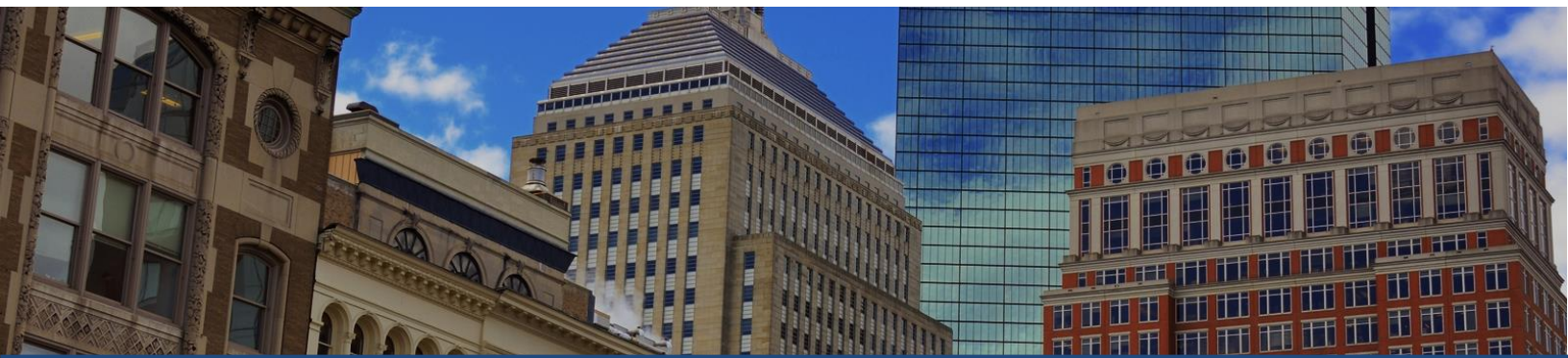


REDACTED



Independent Evaluator Report

on the Solicitation, Evaluation, Bid Selection and Contract Negotiation Process
under Section 83D of the Green Communities Act

Prepared by Peregrine Energy Group
July 24, 2018



Table of Contents

I. Introduction and Executive Summary.....	1
II. Background: 83D and the Role of the IE	3
A. The Energy Diversity Act	3
B. Development of the RFP and its Approval for Issuance	5
C. Independent Evaluator Scope and Standard of Review	7
III. Summary of the Solicitation, Bid Evaluation and Selection Process.....	9
A. Summary of RFP Provisions	9
B. Post-RFP Issuance: Bidder Conference; Answers to Bidder Questions; Development of the Detailed Evaluation Framework	12
1. Bidder Conference	12
2. Questions and Answers	12
3. Development of the Detailed Evaluation Framework	13
a. Introduction.....	13
b. Quantitative Evaluation Protocol and Base Case Development	13
c. Qualitative Evaluation Protocol	19
d. Stage 3 Evaluation Protocol	20
C. Evaluation of the Bids	21
1. Threshold Evaluation	21
2. Stage 2 Quantitative and Qualitative Evaluation.....	23
a. Quantitative Evaluation.....	23
b. Qualitative Evaluation	27
c. Stage 2 Scores and Ranking	28

3. Stage 3 Evaluation of Proposal Portfolios.....	28
D. Bid Selection	31
1. Initial Selection.....	31
2. NPT Denied Siting Approval; Evaluation Team Selects Conditionally Selects NECEC	34
IV. Monitoring the Contract Negotiation Process.....	36
V. Analysis of Solicitation, Bid Evaluation, Selection and Contract Negotiation Process	37
A. Process Issues: Transparency and Independent Oversight; Disclosure of Affiliate Relationships.....	37
i. Transparency.....	37
2. Independent Oversight	39
3. Disclosure of Affiliate Relationships	40
B. Fairness of the Bid Evaluation Framework	41
1. Interconnection Requirements.....	41
2. Detailed Evaluation Framework	43
C. Fairness of the Bid Evaluation and Selection Process.....	48
1. Threshold Evaluation	48
2. Stage 2 and Stage 3 Evaluation and Bid Selection	48
D. Contract Negotiation Process	51
VI. Conclusions	54
Appendix A - Qualifications and relevant experience of the Peregrine independent evaluator team	56
Appendix B - Key provisions of the 83D RFP	58
Appendix C - Bids that did not meet threshold / eligibility requirements.....	67
Appendix D – Large projects: Stage 2 evaluation	68

Appendix E – Small projects: Stage 2 evaluation	69
Appendix F – Stage 3 portfolio summary	70
Appendix G – Stage 3 portfolio summary: Scoring based on alternative \$NPV quantitative evaluation metric as reported by DOER	71

I. Introduction and Executive Summary

On March 31, 2017, Fitchburg Gas & Electric Light Company d/b/a Unitil (“Unitil”), Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid (“National Grid”), NSTAR Electric Company and Western Massachusetts Electric Company d/b/a Eversource (“Eversource”), as investor-owned electric distribution companies (collectively, “Distribution Companies” or “EDCs” and each a “Distribution Company”), in coordination with the Massachusetts Department of Energy Resources (“DOER”), issued a Request for Proposals (“RFP”) pursuant to which the Distribution Companies would solicit proposals for incremental Clean Energy Generation and associated environmental attributes and/or renewable energy certificates (“RECs”) under long-term contracts, which may include associated transmission costs, pursuant to Section 83D of Chapter 169 of the Acts of 2008 (the “Green Communities Act” or “GCA”), as amended by chapter 188 of the Acts of 2016, An Act to Promote Energy Diversity (the “Energy Diversity Act”) (hereinafter, “83D”). The Department of Public Utilities (the “Department”) approved the issuance of the RFP in an order issued on March 27, 2017.¹

Bids were submitted with respect to 53 proposed projects on or by July 27, 2017, the due date for proposals.² Following an extensive evaluation process, on January 25, 2018, an all-hydro bid submitted by an affiliate of Hydro Quebec, Hydro Renewable Energy Inc. (“HRE”), to be delivered through a new transmission project developed by Northern Pass Transmission LLC (“Northern Pass” or “NPT”), an Eversource affiliate, was selected for contract negotiations. A week later, however, the New Hampshire Site Evaluation Committee (“NHSEC”) decided on February 1, 2018 to deny the New Hampshire siting permit for the Northern Pass project.³ Subsequently, the Distribution Companies conditionally selected another high-ranking bid for contract negotiations, while continuing to negotiate with Northern Pass, with the ability to cease discussions with NPT and terminate its conditional selection by March 27, 2018.⁴ HRE was also the power supplier for the competing bid with transmission delivery through a proposed high-voltage direct current transmission (“HVDC”) project—the New England Clean Energy Connect (“NECEC”) project—whose U.S. segment would be constructed by Central Maine Power Company (“CMP”). On March 28, 2018, the Distribution Companies terminated negotiations with Northern Pass and continued their negotiations with NECEC and HRE,⁵ which ultimately led to concluded agreements. These agreements—(a) Power Purchase Agreements (“PPAs”) between the EDCs and a Hydro Quebec subsidiary, H.Q. Energy Services (U.S.) Inc. (“HQUS”) and (b) Transmission Service

¹ Fitchburg Gas and Electric Light Company, et al, D.P.U. 17-32 (2017).

² This number does not include pricing variants for proposed projects. This number also differs from the 46 bids referenced on the RFP website, <https://macleanenergy.com/83d/83d-bids/>, which was based upon the number of CDs (public versions) submitted by bidders, some of which contained multiple project proposals.

³ https://www.nhsec.nh.gov/projects/2015-06/transcripts/2015-06_2018-02-01_transcript_delib_day3_pm.pdf.

⁴ See <https://macleanenergy.files.wordpress.com/2018/02/doer-statement-update-2-16-18.pdf>.

⁵ <https://macleanenergy.com/2018/03/28/83d-selection-update-march-28-2018/>.

⁶ During the contract negotiation stage, the parties agreed that HQUS would replace HRE as the seller. Both HQUS and HRE are affiliates of Hydro Quebec. HQUS is an operating U.S. subsidiary that coordinates Hydro Quebec’s business development and energy marketing activities

Agreements (“TSAs”) between the EDCs and CMP—have been filed for approval with the Department; the TSAs between CMP and the Distribution Companies will also be filed by CMP with the Federal Energy Regulatory Commission (“FERC”).

83D requires that DOER and the Attorney General’s Office (“AGO”) jointly select, and DOER shall contract with, an independent evaluator to monitor and report on the solicitation and bid selection process (Section 83D(f)). Pursuant to that authority, Peregrine Energy Group, Inc. (“Peregrine”) was selected to be the Independent Evaluator (the “IE”) with respect to the 83D solicitation (as well as for the first solicitation for offshore wind generation conducted under Section 83C of the Act).⁷

Section 83D(f) states that the purpose of the Independent Evaluator is to help to “ensure an open, fair and transparent solicitation and bid selection process that is not unduly influenced by an affiliated company” and to assist the Department in its consideration of long-term contracts filed for approval. Among the IE’s responsibilities include the obligation to “file a report with the department of public utilities summarizing and analyzing the solicitation and bid selection process, and providing its independent assessment of whether all proposals were evaluated in a fair and non-discriminatory manner.”⁸ The IE’s role in the 83D RFP was also expanded at the request of DOER, with the approval of the EDCs, to include monitoring of the post-selection part of the process, including contract negotiations.⁹

This is the IE report that summarizes the solicitation, bid evaluation and bid selection process. In addition, it addresses the oversight of the contract negotiation process that the IE performed to assist DOER with respect to DOER’s contract monitoring role in the process.

In this report, the Independent Evaluator summarizes the development of the RFP and the Department’s approval of its issuance, the Evaluation Team’s subsequent development of a detailed evaluation framework, the receipt of bids, the evaluation of bids, bid selection, and the contract negotiation process leading up to the execution of contracts with HQUS and CMP. In addition, the report contains the IE’s assessment of the solicitation process and results in the context of whether the solicitation process and bid evaluation and selection were conducted objectively and in a fair and non-discriminatory manner without undue preference toward any affiliated projects. In the report, the IE has

in the Northeastern United States. HRE, an indirect wholly-owned subsidiary of Hydro Quebec, was established for the export of Hydro Quebec hydropower but does not (based on our understanding) currently engage in the purchase and sale of electric energy.

⁷ Peregrine’s Independent Evaluator team includes subcontractors New Energy Opportunities, Inc., Merrimack Energy Group, Inc., Power Consulting Services, LLC, and Meaden & Moore, LLP. A short summary of the IE team’s qualifications and pertinent experience is set forth in Appendix A to this report.

⁸ 83D(f).

⁹ See <https://macleanenergy.com/2018/03/28/83d-selection-update-march-28-2018/>.



drawn upon precedents of the FERC under the *Edgar-Allegheny* line of cases as guidance in conducting its assessment.¹⁰

This solicitation was a very complex, difficult and lengthy process due to the very different resources and products that were eligible to bid, the magnitude of energy sought—approximately 9,450,000 MWh/year—the participation of multiple Distribution Companies and DOER on an Evaluation Team which aimed to operate on a consensual basis, and the fact that two of the Distribution Companies were affiliated with certain bidders. Allowable bids included firm power from existing hydroelectric resources associated with new transmission projects that competed with unit-contingent intermittent power from new wind and solar Renewable Portfolio Standard (“RPS”) Class I generating facilities, as well as with combinations of these types of resources. Adding to the complexity were changes occurring during the solicitation process after the issuance of the RFP—the promulgation of the Clean Energy Standard (“CES”) regulations by the Massachusetts Department of Environmental Protection (“DEP”), which created new and additional demand for clean energy resources and ISO New England’s proposal, and receipt of FERC approval for, a cluster study interconnection process applicable to certain generation and transmission projects in Maine.

The process was not perfectly conducted, and this report addresses some of the issues that had to be addressed along the way. However, overall, the process was properly and fairly conducted, the bid selection decisions were reasonable and in accordance with RFP criteria, and the resulting contracts were fairly negotiated, in the IE’s opinion.

II. Background: 83D and the Role of the IE

A. The Energy Diversity Act

Section 83D of the Act, signed into law by Governor Baker on August 8, 2016, provides that in order to facilitate the financing of clean energy generation resources, each Massachusetts electric distribution company shall jointly and competitively solicit proposals for clean energy generation and, provided that reasonable proposals have been received, shall enter into cost effective long-term contracts for “clean energy generation” for an annual amount of electricity equal to approximately 9,450,000 megawatt-hours (“MWh”) by December 31, 2022. “Clean energy generation” is defined under Section 83B of the Act as either:

¹⁰ The *Edgar-Allegheny* guidelines were enunciated by FERC in *Boston Edison Electric Co: Re: Edgar Electric Energy Co.*, 55 FERC ¶ 61,382 (1991) and *Allegheny Electric Supply Company, LLC*, 108 FERC ¶ 61,082 (2004).



1. Firm service hydroelectric generation from hydroelectric generation alone (which may include multiple hydroelectric run-of-river generating units managed in a portfolio that creates firm service through the diversity of multiple units);
2. New RPS Class I eligible resources;¹¹ or
3. New RPS Class I eligible resources that are firmed up with firm service hydroelectric generation.

Aside from these three classes of generation resources, Section 83D allows “associated transmission costs to be incorporated into a proposal; provided that, to the extent there are transmission costs included in a bid, the department of public utilities may authorize or require the contracting parties to seek recovery of such transmission costs of the project through federal transmission rates, consistent with policies and tariffs of the Federal Energy Regulatory Commission, to the extent the department finds such recovery is in the public interest.”¹² Hence, several very different types of proposals are allowable under 83D:

- Firm service hydroelectric generation under a PPA;
- New Class I RPS generation, such as wind or solar, firmed by firm service hydroelectric generation under a PPA;
- New Class I renewables, such as wind or solar, under a PPA;
- Any of the foregoing types of generation under PPAs plus transmission under a long-term transmission contract or tariff.

Aside from satisfying the policy directives encompassed within Section 83D, the RFP states that another fundamental purpose of the RFP is to assist the Commonwealth with meeting its goals under the Global Warming Solution Act (“GWSA”), which requires reduction in greenhouse gas emissions in specified percentages by dates certain, including 2020.¹³

83D requires that the Distribution Companies jointly solicit proposals no later than April 1, 2017.¹⁴ Prior to that time, the Distribution Companies and DOER must propose “the timetable and method for

¹¹ “New Class I renewable portfolio standard eligible resources” are “Class I renewable energy generating facilities as defined in section 11F of chapter 25A of the General Laws that have not commenced operation prior to the date of execution of a long-term contract or that represent the net increase from incremental new generating capacity at an existing facility after the date of execution of a long-term contract.” Section 83B.

¹² Section 83D(d)(4)

¹³ RFP Section 1.1.

¹⁴ Section 83D(a).

solicitation of long-term contracts” to the Department, after consulting with the AGO. The Department must approve the issuance of the RFP.

Section 83D contains a number of criteria that are relevant to the design and implementation of the 83D RFP. They include the following criteria applicable to proposals submitted by bidders:

- Contribute to reducing winter electricity price spikes;
- Are cost effective to electric ratepayers in the commonwealth over the term of the contract taking into consideration potential economic and environmental benefits to the ratepayers;
- Avoid electrical line losses and mitigate transmission costs to the extent possible and ensure that transmission cost overruns, if any, are not borne by ratepayers;
- Allow long-term contracts for clean energy generation resources to be paired with energy storage systems;
- Guarantee energy delivery in winter months;
- Adequately demonstrate project viability in a commercially reasonable timeframe.

These and other matters were taken into consideration by the Distribution Companies and DOER in developing and implementing the 83D RFP.

B. Development of the RFP and its Approval for Issuance

In November 2016, DOER and the Distribution Companies commenced work in earnest on development of the 83D RFP.

Under 83D and 83C, DOER and the AGO are responsible for selecting, and the DOER for contracting with, an independent evaluator to monitor and report on the solicitation process. Following issuance of a Request for Quote by DOER on November 23, 2016 for the provision of Independent Evaluator services, Peregrine and its subcontractors were selected to serve as Independent Evaluator for the 83D solicitation and the first 83C solicitation. Peregrine started work on December 28, 2016.

The IE reviewed draft RFP documents and attended meetings and conference calls with respect to development of the RFP. The IE’s review focused on the elements of the RFP which were relevant to the IE’s scope of review and concerns. The IE provided its feedback to the Distribution Companies and DOER. Some of the IE’s suggestions were incorporated into the RFP, while others were considered but were not incorporated. Of those suggestions not incorporated, the IE was for the most part satisfied with the rationale for maintaining the approach as drafted.

In the Distribution Companies and DOER’s development of the RFP evaluation criteria, not all issues were fully decided but were left for further development and agreement through price and non-price evaluation protocols that were to be developed over the next few months. This was due to two major

factors: (1) timing constraints associated with the statutory requirement that the solicitation be issued on or by April 1, 2017; and (2) the complexity of the solicitation process. The RFP needed to be structured to provide for evaluation of bids with and without transmission, and with types of generation having different characteristics and industry practices.

The Distribution Companies filed the proposed RFP with the Department on February 2, 2017, seeking approval under 83D(b) of the “timetable and method for solicitation of long-term contracts.” Shortly thereafter, Peregrine submitted its IE report, as required by 83D(f), analyzing the draft RFP and including any recommendations for improving the process consistent with the statutory objective of “ensur[ing] an open, fair and transparent solicitation and bid selection process that is not unduly influenced by an affiliated company.” The IE suggested four modifications to the draft RFP:

- RPS Class I resources should not be required to incorporate in their bids the cost of network upgrades that go beyond those required to satisfy the ISO New England (“ISO-NE”) Capacity Capability Interconnection Standard (“CCIS”);
- The Distribution Companies and DOER—the Evaluation Team—should be allowed to modify the requirement that bidders must provide studies based on the current serial ISO-NE interconnection study system in light of the evolving status of a proposal by ISO-NE to convert partially to a cluster study system;
- In the event that the Evaluation Team subsequently determines that RPS Class I RECs will be valued in a way that is comparable to the valuation of the hydroelectric generation environmental attributes that do not qualify under the RPS, the RFP and form PPA provisions allowing the Distribution Companies to not pay for RECs if the RECs no longer qualify under the RPS due to a change in law should be eliminated because there are no similar provisions applicable to hydroelectric generation environmental attributes;
- Transmission bidders should be required to limit the recovery of abandoned plant cost at the FERC, if such recovery is sought, to costs incurred after the issuance of the RFP, and a winning transmission bidder should not have any right to recover abandoned plant costs from the Distribution Companies unless and until contracts have been executed and required regulatory approvals have been obtained, subject to any other negotiated limitations.

Over 20 parties, including the AGO, submitted comments to the Department on the proposed RFP. In response to some of the comments, the Distribution Companies provided clarifying changes to the RFP’s definition of the RPS Class I firmed by hydro bid category (Section 2.2.1.3.ii) and the winter energy guarantee requirement (Section 2.2.2.7).¹⁵

¹⁵ <https://eeaonline.eea.state.ma.us/EEA/FileService/FileService.Api/file/FileRoom/9188427>. In addition, the Distribution Companies added a requirement for energy pricing to RFP Section 2.2.1.4 to address instances of negative pricing, which had been inadvertently omitted from the 83D RFP. <https://eeaonline.eea.state.ma.us/EEA/FileService/FileService.Api/file/FileRoom/9187992>.



On March 27, 2017, the Department approved for issuance the proposed RFP (as revised) with minimal changes.¹⁶ On March 31, 2017, the Evaluation Team posted the RFP on the website for the RFP process, www.macleaneenergy.com. Also posted on the RFP website were the form model contracts for (a) RPS Class 1 energy resources, (b) firm hydroelectric generation resources, and (c) RPS Class I energy resources firmed by hydro, as well as a summary of terms to be addressed for proposed transmission service agreements, and forms to be filled out by bidders.¹⁷ Email notification of the posting was sent out to a notification list of approximately 650 industry participants and stakeholders.

C. Independent Evaluator Scope and Standard of Review

The Energy Diversity Act sets forth the standard of “open, fair and transparent” with regard to the solicitation and bid selection process and one that is “not unduly influenced by an affiliated company.” The Department has applied essentially the same standards in approving for issuance the Clean Energy RFP under Section 83A of the GCA.¹⁸ There, the Department stated that “the RFP may result in the submission of bids from the electric distribution companies’ affiliates or include projects in which the electric distribution companies or their affiliates have a financial interest,” thus, requiring “safeguards. . . to ensure that no potential bidder receives preferential treatment.”¹⁹ Similarly, there was the prospect for the 83D solicitation (as well as for 83C)—which turned out to be realities—that Distribution Company affiliates, or projects in which the Distribution Companies or their affiliates have a financial interest, would be bidders. In enacting 83D (as well as 83C), the Massachusetts Legislature required the retention and use of an Independent Evaluator as a safeguard to help ensure the openness, fairness and transparency of solicitations to be issued and to safeguard against any undue preferences toward EDC affiliates or unjust discrimination against any bidder.

FERC has enunciated what are sometimes referred to as the *Edgar-Allegheny* principles in decisions involving transactions between affiliates in which the buyer is a regulated utility. In the *Edgar* case in 1991, FERC required that a seller of wholesale electric power making a sale to an affiliated regulated utility for resale at market-based rates demonstrate that the rates and other terms and conditions of the power

¹⁶ The Department’s interpretation of its scope of review under 83D—the “timetable and method for soliciting long-term contracts”—is narrow. Fitchburg Gas and Electric Company et al., D.P.U. 17-32 (2018) at 18-19. The Department directed the Distribution Companies to correct inconsistencies regarding the time period that bidders must hold open their bids, which they had already agreed to do, *Id.* at 40, but did not require any other changes to the proposed RFP, including those suggested by the IE. This report addresses, among other things, how the issues raised by the IE in its initial report to the Department were managed in the implementation of the RFP process.

¹⁷ The model PPAs and summary of terms for transmission service agreements had not been previously provided to the Department with the RFP in connection with the Department’s approval of the issuance of the RFP. This was in accordance with past Massachusetts RFP practices.

¹⁸ Fitchburg Gas and Electric Company et al., D.P.U. 15-84 (2015) at 43-45 (“fair, transparent, and competitive” and “fair, open, and transparent”).

¹⁹ *Id.* at 43-44.



sales contract are not unduly preferential to the seller.²⁰ Where there is a competitive procurement process, FERC has required assurance that:

1. The process was designed and implemented without undue preference for the affiliate seller,
2. The analysis of the bids or responses did not favor the affiliate, particularly with respect to evaluation of non-price factors, and
3. Selection was based on some reasonable combination of price and non-price factors.²¹

In *Allegheny Electric Supply Company, LLC*, 108 FERC ¶ 61,082 (2004), FERC set forth guidelines applicable to its review of competitive solicitation processes under the *Edgar* standards.

1. “Transparency: the competitive solicitation process should be open and fair.
2. Definition: the product or products sought through the competitive solicitation should be precisely defined.
3. Evaluation: evaluation criteria should be standardized and applied equally to all bids and bidders.
4. Oversight: an independent third party should design the solicitation, administer bidding, and evaluate bids prior to the company’s selection.”

Subsequently, FERC found it sufficient for the independent third party to have overseen the design and implementation of the competitive bidding process, rather than to conduct the process itself.²² The purpose of the FERC guidelines is to provide assurance that regulated electric utilities do not unduly favor their affiliates, to the detriment of their customers.

Peregrine views the 83D (and 83C) standard of “open, fair and transparent” and “not unduly influenced by an affiliated company” to be substantially the same as the *Edgar-Allegheny* principles enunciated by FERC. Hence, the Independent Evaluator has viewed the *Edgar-Allegheny* principles as providing guidance in its review of the design and implementation of the 83D RFP.²³

²⁰ Boston Edison Electric Co: Re: Edgar Electric Energy Co., 55 FERC ¶ 61,382 (1991) (“Edgar”).

²¹ *Edgar*, 55 FERC ¶ 61,382 at 62,128.

²² *Southern California Edison Company: Re Sycamore Cogeneration Company*, 142 FERC ¶ 61,101 (2013). The role of the Independent Evaluator in competitive bidding processes conducted by electric utilities regulated by the California Public Utilities Commission typically involves an oversight function, rather than the actual conduct of the competitive solicitation.

²³ The FERC guidance also has practical implications for the 83D and 83C solicitation processes. Any PPA resulting from the solicitation process in which the seller is an affiliate of one of the Distribution Company buyers would require FERC approval under *Edgar-Allegheny*. In addition, there is, in our view, a substantial likelihood that FERC would apply the *Edgar-Allegheny* principles to review (a) any transmission service agreement or tariff in which the transmission owner is an affiliate of a Distribution Company resulting from this solicitation and/or (b) any associated PPA, even where the seller under the PPA is unaffiliated with the Distribution Company. See, e.g., *Ameren Electric Generating*

There are other contextual matters that have been important for our review. The requirement for an Independent Evaluator is a matter of Massachusetts law which applies regardless of whether there are affiliate bids or affiliate contracts, and 83D(f) requires the IE to provide “its independent assessment of whether *all* bids were evaluated in a fair and non-discriminatory manner” (emphasis added). Hence, we view the standard of “open, fair and transparent” as being applicable without regard to any specific concerns regarding undue preferences being provided toward affiliates. Also, we note the industry practice where independent evaluators are used, or have been used, to oversee the conduct of competitive solicitations in a variety of states, including California, Nevada, and Delaware.²⁴ Importantly, we also take into consideration key differences between the 83D/83C process and other solicitations overseen by independent evaluators. Typically, a single electric utility conducts a solicitation, which is overseen by an independent evaluator. Here, multiple distribution companies are conducting the solicitation in coordination with the state energy policy agency, DOER, and the RFP design phase also includes the involvement of the state’s consumer advocacy agency, the AGO. Also, the issuance of the RFP requires Department approval after providing for opportunity to comment by industry stakeholders and prospective bidders. The multiplicity of interests involved in the design and implementation of the solicitation may reduce the potential for one or more Distribution Company affiliates to be recipients of undue preferences, but does not eliminate it. The Independent Evaluator has taken into consideration the composition of the procurement team but has been guided by the *Edgar-Allegheny* principles in the conduct of its responsibilities.

III. Summary of the Solicitation, Bid Evaluation and Selection Process

A. Summary of RFP Provisions

The RFP specifies the products being solicited, also referred to as “Eligible Bid Categories,” identifies the threshold requirements applicable to all proposals, and describes the evaluation criteria and process to be used in evaluating the proposals. In addition, the RFP identifies the timetable for a bidder conference, a question and answer period, submission of bids, bid evaluation and selection, and

Company, 108 FERC ¶61,081 (2004) (acquisition of generating facilities from an affiliate under Section 203 of the Federal Power Act) reviewable under the *Edgar* standards); *Southern California Edison Company on behalf of Mountainview Power Company, L.L.C.*, 106 FERC ¶61,183 (2004) (all power purchases from affiliates, whether under market-based rates or cost-based rates, of at least one year in duration will be subject to the *Edgar* standards). In this context, it was prudent to establish and implement a solicitation process that would satisfy the *Edgar-Allegheny* principles.

²⁴ See Opinion Adopting Pacific Gas and Electric Company’s, Southern California Edison Company’s, and San Diego Gas & Electric Company’s Long-Term Procurement Plans, D.07-12-05 (CPUC 2007) at 131-142, http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/76979.PDF, https://www.nvenergy.com/company/doingbusiness/rfps/Emissions-Capacity_RFP.cfm (NV Energy renewable energy RFP); 26 Del C. §1107(d)(2) (requiring retention of an independent consultant for solicitation of long-term contracts), <http://delcode.delaware.gov/title26/c010/>. Other states with formal competitive bidding rules and/or guidelines which require an Independent Monitor or Independent Evaluator, at least for solicitations in which a utility-ownership or affiliate option is present, include, Georgia, Louisiana, Oklahoma, Oregon, Utah, and Hawaii.



contract negotiation and execution, and submittal to the Department of contracts executed as a result of the solicitation. The RFP appendices include a bidder response package, standards of conduct, and form contracts/contract terms against which bidders may submit exceptions.

The RFP sets forth four eligible bid categories, with applicable requirements for each category:

- Proposal to sell Incremental Hydroelectric Generation (including environmental attributes) on a firm \$/MWh basis pursuant to a PPA;

If the proposed Clean Energy Generation specified for delivery in an hour is not delivered, the seller will be responsible for payment of liquidated damages;

- Proposal to sell new Class I RPS eligible resources (energy and RECs or RECs only on a \$/MWh basis) pursuant to a PPA;
- Proposal to sell new Class I RPS eligible resources firmed by Incremental Hydro Generation pursuant to a PPA;

If the proposed Clean Energy Generation specified for firm delivery in an hour is not delivered, the seller will be responsible for payment of liquidated damages;

- Any of the foregoing types of PPA proposals packaged with a proposed transmission project with payments to be made under a FERC tariff and service agreement.²⁵

The evaluation of the bids is to be conducted in three stages. In the first stage, the Evaluation Team reviews bids for compliance with various eligibility and threshold requirements (although this review may take place throughout the evaluation period). Among the eligibility/threshold requirements are the following:

- Term length of proposed contract: 15-20 years from commercial operation
- Allowable pricing:
 - a. Seller to take energy price risk associated with negative Locational Marginal Price ("LMP) at the delivery point
 - b. Seller of Class I RECs to take RPS change in law risk; pricing for Clean Energy Generation and Class I RECs must closely align with the relative market value of those products
 - c. For transmission projects, fixed prices are encouraged, but significant cost containment features are required for bids with cost of service pricing

²⁵ RFP Section 2.2.1.3.

- Bidders are responsible for all costs associated with interconnecting their projects using the Capacity Capability Interconnection Standard, although bidders are not required to clear their proposed projects in ISO-NE's Forward Capacity Market
- Site control:
 - a. Bidders of generation projects must demonstrate site control
 - b. Bidders of transmission projects must demonstrate a reasonable and achievable plan to obtain site control
- Ability to finance the proposed project (financial viability)
- Ability to develop, finance and construct the proposed project in a commercially reasonable timeframe (project viability).

In Stage Two, projects that satisfy the Stage One requirements are evaluated quantitatively and qualitatively. The result of this analysis is a relative ranking and scoring of all individual proposals. Stage Two scoring is on a 100-point scale, with a maximum 75-point score based on the quantitative evaluation and a maximum 25-point score based on the qualitative evaluation.²⁶

The RFP describes the direct contract costs and benefits to be evaluated for energy, RECs and transmission as well as other benefits and costs for evaluation, such as the impact of changes to LMPs paid by EDC customers and the impact of the proposal for contributing to meeting the Commonwealth's GWSA requirements, as determined by the Evaluation Team.²⁷

The RFP describes a number of factors for inclusion into the qualitative evaluation, such as bidder experience with similar projects, credibility of the project schedule, progress in the interconnection process, status of the project's community relations plan, credibility of the project's energy resource assessment, extent to which the project can support GWSA requirements by delivering energy on or before December 31, 2020, reliability benefits, price firmness and price risk, the extent to which proposed contract terms do not shift risks to the EDCs and their customers, environmental impacts from siting, and economic benefits to the Commonwealth.²⁸

The RFP provides that the Evaluation Team will select proposals from Stage Two for consideration in Stage Three taking into consideration rank order and cost effectiveness from the Stage Two evaluation

²⁶ RFP Section 2.3.

²⁷ RFP Section 2.3.1.

²⁸ RFP Section 2.3.2. A change was made to RFP Section 2.3.2 in June 2017 to conform with RFP Section 1.1 ("the Distribution Companies encourage proposals which include Clean Energy Generation able to commit to begin deliveries prior to the end of 2020 to maximize the Commonwealth's ability to meet its Global Warming Solution Act ("GWSA") goals"). See https://macleanenergy.files.wordpress.com/2016/12/83d-rfp-and-appendices-final_june-12-2017-conforming-changes-redlined.pdf.

and the annual procurement target—9,450,000 MWh.²⁹ In Stage Three, the Evaluation Team is to develop portfolios of projects based on the annual procurement target to determine overall cost effectiveness and impact on the Commonwealth’s policy goals, as directed by DOER, including GWSA goals.³⁰ In Stage Three, other factors may be considered by the Evaluation Team, such as risks associated with project viability of the proposals, any risks to customers associated with transmission projects and benefits to customers that may not have been fully captured in the Stage Two evaluation.³¹

The timeline in the RFP (subject to modifications as determined by the Evaluation Team) called for a bidder conference, a due date for bidder questions to the Evaluation Team, bids to be submitted by July 27, 2017, bid selection by January 25, 2018, contract execution by March 27, 2018, and submittal of contracts for Department approval by April 25, 2018.³²

A more detailed summary of RFP terms is provided in Appendix B to this report.

B. Post-RFP Issuance: Bidder Conference; Answers to Bidder Questions; Development of the Detailed Evaluation Framework

1. Bidder Conference

The Evaluation Team held a bidder conference at Eversource’s offices in Westwood, Massachusetts on April 25, 2017, with a presentation provided on the solicitation and bid evaluation process.³³ There were over 90 attendees. Bidder questions were entertained, but prospective bidders were advised that questions needed to be submitted in writing in order for the Evaluation Team to provide an official response.

2. Questions and Answers

Bidders submitted over 100 questions in writing. The questions were submitted to a dedicated email account, which was the specified method by which prospective bidders could communicate to the Evaluation Team. The Evaluation Team provided written responses in batches as responses were finalized.³⁴ All responses were posted on the RFP website by June 30, 2017. The responses were a collaborative effort by the Distribution Companies and DOER, with IE oversight to assure consistency with the RFP, accuracy, and fairness.

²⁹ *Id.*

³⁰ RFP Section 2.4.

³¹ *Id.*

³² RFP Section 3.1.

³³ <https://macleanenergy.com/83d/83d-bidder-conference/>.

³⁴ <https://macleanenergy.com/83d/83d-q-a/>.



3. Development of the Detailed Evaluation Framework

a. Introduction

After issuance of the RFP, a key activity was to develop evaluation protocols for the Stage 2 quantitative evaluation, the Stage 2 qualitative evaluation, and the Stage 3 evaluation. Contemporaneously with the Stage 2 quantitative evaluation protocol, the Evaluation Team worked with the Evaluation Team's consultant, Tabors Caramanis Rudkevich ("TCR"), to develop a base case for evaluation. These were steps required to implement the broad terms of the RFP and to provide guidance to the Evaluation Team for the evaluation of bids on a fair and non-discriminatory basis. The Evaluation Team also developed a checklist of eligibility and threshold requirements to aid in the Stage One evaluation. Finally, the Evaluation Team organized itself into several committees: a Steering Committee to oversee the work of the Evaluation Team, a Quantitative Committee responsible for the development and implementation of the detailed quantitative evaluation, and a Qualitative Committee responsible for development and implementation of the detailed qualitative (non-price) evaluation. Later, committees were also set up to focus on the threshold requirements evaluation and transmission matters.

This section of the report summarizes the development of the detailed framework for the evaluation of bids.

b. Quantitative Evaluation Protocol and Base Case Development

Work on development of the base case and the detailed quantitative evaluation framework began in earnest in June 2017 after the Distribution Companies retained TCR as the Evaluation Team Consultant, the Evaluation Team had responded to most of the bidder questions, and the draft offshore wind RFP under Section 83C of the Energy Diversity Act had been filed with the Department for approval.³⁵ TCR proposed utilization of the ENELYTIX model to evaluate the energy, REC and clean energy attribute costs and carbon emissions impacts of proposals submitted by bidders relative to a base case.³⁶ The base case would be developed by TCR working in conjunction with the Evaluation Team under the oversight of the

³⁵ Under Section 83C(a), the Distribution Companies were required to jointly issue a RFP for long-term contracts from offshore wind resources on or by June 30, 2017, following Department approval. In order to meet that statutory deadline, most of the 83D Evaluation Team worked on development of the 83C RFP in March and April 2017 so that it could be filed with the Department by the end of April 2017 (it was filed on April 28, 2017). The Distribution Companies retained the Evaluation Team Consultant (under the 83D RFP, the firm retained "to assist the Evaluation Team with the technical methodologies and findings for eligible proposals") in June 2017.

³⁶ The ENELYTIX model has three module components: (a) a capacity expansion module to determine the long-term optimal electric system expansion in New England, subject to capacity, RPS, and environmental requirements; (b) the energy and ancillary services module which simulates the day-ahead and real-time operations of the power system and power markets on a nodal basis; and (c) an ISO-NE FCM module which is used to compute capacity prices. The objective function is to minimize the total cost of the wholesale generation fleet serving the ISO-NE market. The ENELYTIX model and the modeling approach is described in more detail in a report provided by TCR to the Distribution Companies.

Independent Evaluator. Key assumptions for the base case were developed in parallel with the quantitative evaluation framework which would be embodied in a quantitative evaluation protocol.

The base case is a “but for” case against which all of the 83D bid proposals would be evaluated. The base case assumed that the Distribution Companies would not purchase energy, RECs and environmental attributes under long-term contracts pursuant to 83D. However, under the base case, all other legislative and regulatory mandates then in effect and certain proposed rules were assumed to be satisfied. These included: (a) RPS rules in Massachusetts and the other New England states; (b) compliance with new Massachusetts Clean Energy Standard (“CES”) rules (final rules were issued on August 11, 2017 and amended on December 8, 2017), which set a minimum percentage of clean energy that distribution companies and competitive suppliers must purchase as a percentage of their total sales (in addition to complying with the Massachusetts RPS);³⁷ as well as (c) new limitations imposed on carbon dioxide emissions from Massachusetts fossil fuel-powered electric generating facilities (also made effective in August 2017).³⁸ The purpose of these new rules was to facilitate compliance with the GWSA, which requires an 80 percent reduction in greenhouse gas (“GHG”) emissions by 2050, with an administratively-determined goal of 25 percent reductions by 2020. In addition, it was assumed that 1600 MW of offshore wind energy generation would be built pursuant to the 83C mandate to conduct solicitations for 1600 MW of long-term contracts for energy and RECs from offshore wind energy generation facilities.

Development of the base case involved making a variety of key assumptions involving fuel costs, load forecasts, RPS and CES requirements, and imports. The load forecast was based on the ISO New England 2017 CELT (Capacity, Energy, Loads and Transmission) report, with an extrapolated load forecast beyond 2026 (the last year covered in the 2017 CELT report). The assumptions for development of the base case (which were also common to modeling of proposal cases and portfolio cases) are described more fully in TCR’s Quantitative Evaluation Report which has been filed with the Department.

The detailed quantitative evaluation framework, described in the quantitative evaluation protocol, consisted of a benefit/cost analysis using the ENELYTIX modeling tool with two categories of benefits and costs—(1) direct contract costs and benefits and (b) indirect costs and benefits. Importantly, the evaluation framework incorporated the effects of the newly-enacted CES (as amended), which provided that all hydroelectric generating attributes procured and retained under the 83D solicitation and RPS Class I-qualifying resources will be CES-compliant.

Direct costs of a proposed project would include the bidder’s proposed cost of energy, the proposed cost of RECs for RPS Class 1-compliant bids, and for proposals with transmission, the proposed cost of transmission service. Against these costs, the market value of energy at the delivery point would be

³⁷ <http://www.massdep.org/BAW/air/cesf-amend.pdf>.

³⁸ <http://www.mass.gov/eea/docs/dep/air/climate/3dregf-electricity.pdf>.



calculated on a nodal basis with the project in service. In addition, the market value of RECs (for RPS-compliant projects), and the market value of Clean Energy Credits (“CECs”) (for CES-compliant projects), would be calculated. Wind, solar, and other projects that are compliant with RPS Class I and the CES would obtain value for the projected value of RECs/CECs. Hydroelectric generation procured under 83D would obtain value for the projected value of CECs.³⁹

The indirect benefits (or costs) associated with a proposal included:

- The impact of changes in LMPs (locational marginal prices) to Massachusetts Distribution Company customers as a result of the proposed project (or portfolio of projects);⁴⁰
- The cost reductions to Massachusetts EDC customers in RPS/CES compliance costs due to reductions in REC and/or CEC market prices as a result of purchases of RECs/CECs from the proposed project (or portfolio of projects);
- The value of a proposal’s contribution toward meeting GSWA requirements over and above the value of compliance with the RPS and CES;
 - This value was based on simulating the impact on the GHG inventory that is used by the Massachusetts Department of Environmental Protection (“DEP”) (for assessing the Commonwealth’s GWSA compliance) to calculate the inventory impact of a proposed project in reductions in metric tons of carbon dioxide equivalent emissions attributed to Massachusetts;
 - The quantity of GHG reductions is then multiplied by the base case emissions rate (GHG/MWh) to obtain a MWh equivalent of GHG emissions reductions (subject to further adjustment, as described later in this section);
 - The resulting MWh value is multiplied by the estimated avoided cost per MWh of obtaining incremental clean energy to obtain the total GHG inventory impact;
 - Preliminarily, this avoided cost was estimated to be \$20/MWh, but after the bids were evaluated in Stage 2, the amount was recalculated based on the median net direct cost without REC/CEC revenues (total costs minus energy revenues) per MWh of qualifying bids in the Stage 2 evaluation;
- The “hedge value” associated with the proposal during periods of high natural gas prices;
 - The three winter month period with the highest prices in the last 15 years was applied to a single power year (2023/2024), with the proposed project in place, to assess the relative

³⁹ 310 CMR 7.75 (2), (6), (7). RECs and CECs that were retained by the Distribution Companies would be valued at their avoided cost (the base case value), while RECs and CECs that were sold would be valued at their market price.

⁴⁰ The Evaluation Team considered whether to use LMP impacts or a combination of LMP impacts and share of production cost savings as a measure of indirect customer benefits. AT TCR’s recommendation, LMP impacts alone were valued on the basis that they are a more direct measure of customer savings.



response to high natural gas prices, and a 1 in 15 year frequency was applied to calculate an impact on a \$/MWh basis.

- This “hedge” or “insurance value” was a method of implementing the RFP’s inclusion of “the economic impacts associated with resource firmness” (RFP section 2.3.1.2.iv) as a quantitative benefit in the context of 83D(d)(5)(ii)’s criterion that clean energy resources “contribute to reducing winter electricity price spikes.”⁴¹

The economic metric by which bids were to be evaluated was real levelized \$/MWh (2017\$). This metric had been recommended by TCR and DOER’s consultant Levitan and Associates (“LAI”).⁴² Other financial parameters were nominal inflation—2 percent, a nominal discount rate of 6.99 percent, and a real discount rate of 4.89 percent.

Under the RFP, the maximum number of points for the most cost-effective bid quantitatively in real \$/MWh was 75, with a maximum of 25 points for the qualitative evaluation. Bids other than the highest ranking bid in the quantitative evaluation would receive a number of points based on the ratio of the bid’s \$/MWh net benefit to that of the highest ranking bid multiplied by 75. For example, if the highest ranking bid in the quantitative evaluation was \$25/MWh and the second ranking bid was \$20/MWh, the highest ranking bid would receive 75 points and the second ranked bid would receive 60 points ($20/25 \times 75$), subject to an outlier exception.

The Evaluation Team spent considerable time with TCR in the development of key assumptions for the economic analysis. If RPS supply was forecasted to be short of RPS demand, it was assumed that generic merchant RPS eligible generation would fill the gap using the ENELYTIX capacity expansion model. However, with respect to the CES, the model did not “solve for” the addition of CES-compliant generation. Instead, CES-compliance would be satisfied by either economic generation or by Alternative Compliance Payments (“ACP”), which beginning in 2021 would be 50 percent of the ACP under the Massachusetts RPS (in 2017, the ACP for RPS Class 1 is \$67.70; 50 percent of that is \$33.85).⁴³ This approach took into consideration the uncertainty as to whether the market alone would produce clean energy generation projects in the absence of long-term contracts (based on historical experience in New England). If there was a surplus of RECs or CECs, a \$2 market price was assumed, based on an amount to cover transaction costs.

⁴¹ Other indirect benefits were considered but were not ultimately incorporated in the final evaluations. The Evaluation Team considered the indirect impacts on capacity or ancillary service market prices with the proposed project in service (see RFP Section 2.3.1.2.v). However, there was insufficient data to determine the impact of proposed projects on ancillary services market prices (sometimes referred to as renewable integration costs) and the indirect impacts on market capacity prices were initially considered but were discarded when the results were deemed unreliable by the Evaluation Team. The IE concurred with these determinations. These considerations, however, were incorporated in the qualitative evaluation’s reliability criterion.

⁴² Also advising DOER was nFront Consulting, a subcontractor to LAI.

⁴³ In 2018-2020, the CES ACP is 75 percent of the RPS ACP during those years.

Bids were submitted on the due date of July 27, 2017. At that time, the Evaluation Team had not finalized the evaluation protocols, particularly the quantitative evaluation protocol. Prior to receipt of the bids, the Evaluation Team decided, with the IE's concurrence, that a specific person or persons for each Distribution Company would review information associated with the bids and wire transfer information to assess the adequacy of the bid fees. These persons would not communicate with other Distribution Company personnel involved in finalizing the evaluation protocols and the base case. With this limited exception, Distribution Company personnel would not review or have access to the bids pending the Evaluation Team's determination that the evaluation protocols and base case were effectively completed. Similarly, DOER and IE personnel working on finalization of the evaluation protocols and base case would not review the bids until the Evaluation Team determined that the evaluation protocols and base case were effectively completed. The purpose of this arrangement was to minimize the potential for review of the bids to influence decisions on the evaluation protocols, especially since there were expected to be bidders who would be affiliated with one or more of the Distribution Companies. On August 2, 2017, the Evaluation Team determined that the evaluation protocols were effectively complete, subject to further adjustments deemed necessary by the Evaluation Team, and evaluation of the confidential bids commenced. Over the next weeks and months, the base case and the quantitative evaluation protocol were further refined.

It was determined that for small projects that only direct benefits would be included in the Stage 2 quantitative evaluation, and that small projects would be compared and ranked against other small projects. The primary reason for this was that the Evaluation Team determined, based on initial modeling results, that the indirect benefit results from the ENELYTIX modeling appeared to be due to modeling "noise" rather than realistic impacts from projects. The IE did not see this approach as being inappropriate or discriminatory. Higher ranked smaller projects could be selected for inclusion in portfolios of approximately 9.45 TWh for Stage 3 evaluations, where the smaller projects in conjunction with other projects would be evaluated on the same basis as the larger projects, with both direct and indirect benefits evaluated.⁴⁴

The Evaluation Team operated by consensus. For the most part, the Evaluation Team members worked effectively together, although it took more time to make decisions than if the evaluation was being conducted by a single entity. The one area where the Evaluation Team was unable to reach consensus in developing the detailed evaluation framework was with respect to one important aspect of the methodology to determine contributions to meeting GWSA requirements.

DOER, supported by Eversource and Unitil, viewed the GWSA contribution value as being incremental to the market value for RECs and CECs that would be retired by the EDCs or Massachusetts competitive retail suppliers but not as separate additional values. As a result, in determining the *net* GWSA

⁴⁴ TCR defined projects as "small" if their generation capacity contribution for qualification in the Forward Capacity Market was less than or equal to 140 MW or its annual generation of RECs or CECs was less than 670 GWh/year. These thresholds were selected because they were not expected to reduce or delay the need for generic peaking capacity or to have an impact on REC/CEC market prices.

contribution in MWh, the DOER proposed methodology subtracted the amount of RECs and CECs (1 REC or CEC is equal to 1 MWh) forecasted to be retired in Massachusetts from the MWh-equivalent amount of carbon dioxide emissions attributable to a proposal compared to the base case. DOER viewed this approach as avoiding “double counting” of clean energy generation attributes.

The impact could be different for environmental attributes associated with hydroelectric generation (“Environmental Attributes” or “EAs”)—which could qualify as CECs but not RECs—compared to RPS Class 1 resources due to a provision of the 83D legislation, which requires that the EDCs retain the Environmental Attributes.⁴⁵

National Grid objected to this *net* approach, asserting that the RPS and CES created a market for environmental attributes and a marketable REC and CEC product that is different from and in addition to the value of reducing GHG emissions in a way that contributes to Massachusetts meeting its GWSA goals. National Grid proposed to calculate GWSA contributions in the same way as proposed by DOER but without deducting the MWhs associated with meeting RPS or CES requirements. After numerous discussions, National Grid stated that it would not accede to the other members of the Evaluation Team with respect to this aspect of the evaluation framework. The company proposed that it would evaluate proposals based on its proposed method, and if it resulted in the company making a different bid selection decision than the other EDCs, DOER could make the final decision after consulting with the IE, as provided by 83D.

The IE expressed the view that in the event of a failure to reach agreement on an important issue, the dispute resolution approach set forth in the statute could be applied to issues other than bid selection. However, National Grid expressed disagreement, and there was no consensus reached on a process to

⁴⁵ Section 83D(f) provides:

An electric distribution company may elect to use any energy purchased under such [83D] contracts for resale to its customers, and may elect to retain renewable energy certificates to meet the applicable annual renewable portfolio standard requirements under said section 11F of said chapter 25A. If the energy and renewable energy certificates are not so used, such companies shall sell such purchased energy into the wholesale market and shall sell such purchased renewable energy certificates attributed to Class I renewable portfolio standard eligible resources to minimize the costs to ratepayers under the contract; provided, further, that a *distribution company shall retain renewable energy certificates that are not attributed to Class I renewable portfolio standard eligible resources* (emphasis added).

With regard to Environmental Attributes, the MWhs used to meet the Distribution Companies’ CES obligations would be valued as CECs and would be deducted from the MWh-equivalent GHG contribution of a proposal, but the amount in excess would not be valued as CECs and would not be deducted in the GWSA contribution calculation because the Environmental Attributes would be retained by the Distribution Company. With regard to RPS Class I resources, similarly the RECs and CECs used to meet Massachusetts RPS and CES obligations would be deducted from the GWSA contribution calculation to avoid double counting of the value of the environmental attributes. However, where the market is in surplus, the RECs would be sold to comply with the 83D legislative mandate to sell them into the wholesale market. It was assumed that a share of them (based on defined criteria) would be retained in Massachusetts for voluntary sales, and this amount would be included in the GWSA contribution calculation—the remainder would not contribute to meeting GWSA requirements in the Massachusetts inventory. To be clear, the MWhs deducted in the GWSA contribution calculation because they would be valued as RECs or CECs, as applicable, would be valued as direct benefits of a project proposal.

reach a decision. National Grid requested that TCR perform a calculation of net benefits using its proposed approach in addition to the calculations performed for the majority of the Evaluation Team. Under these circumstances, the IE opined that the workbooks using the DOER approach should be viewed as the “official workbooks” and that the calculations performed for National Grid be in separate workbooks to avoid confusion. Without taking a position on the substance of the issue in dispute, the IE explained that the DOER method should be viewed as the “official” evaluation because it was supported by the majority of the Evaluation Team and that the issue involved energy policy matters and an interpretation of agency regulations and programs, which entitled DOER to some deference on the particular matter. National Grid expressed the hope that its different way of calculating net economic benefits would not result in differences in bid selection.⁴⁶ As it turned out, the different approaches did not result in significant differences in the bid evaluation results. The evaluation process proceeded.

c. Qualitative Evaluation Protocol

Under the RFP, a total of 25 maximum points was allocated to the qualitative evaluation component of Stage 2 of the evaluation process. In May 2017, a subgroup of the Evaluation Team began to develop the detailed evaluation framework for the qualitative evaluation, which would be embodied in a qualitative bid evaluation protocol.

The starting points were the 83D RFP and a prior qualitative evaluation protocol used in the multi-state RFP, which was conducted (from a Massachusetts standpoint) under Section 83A of the Green Communities Act. The objective was to modify the protocol previously used for applicability to the 83D RFP.

The qualitative criteria listed in Section 2.3.2 were extensive, including the general categories of overall project viability, operational viability, contributions to GWSA goals by the end of 2020, siting and permitting, reliability benefits, price firmness, contract risk, environmental impacts from siting, and economic benefits to the Commonwealth. The first step in the process was to ensure the qualitative criteria listed in the RFP were appropriately addressed in the bid evaluation. As part of this process, the Evaluation Team reviewed whether some of the criteria would be effectively addressed in the quantitative evaluation or whether certain outputs from the quantitative evaluation could be used and incorporated into the qualitative evaluation.⁴⁷ Otherwise, evaluation criteria would be addressed qualitatively as part of the qualitative bid evaluation.

⁴⁶ With the single exception that MWhs associated with meeting RPS and CES requirements were not deducted in the GWSA calculation, TCR performed the GWSA indirect benefit calculation for National Grid in an identical manner as for the calculations for the remainder of the Evaluation Team. National Grid also expressed reservations with the manner in which the avoided cost of clean energy in \$/MWh was calculated by the Evaluation Team.

⁴⁷ For example: curtailment risk (RFP section 2.3.2.ii) was considered to be adequately addressed in the quantitative evaluation and was not incorporated into the qualitative evaluation protocol; the extent to which a project could contribute to GWSA goals by delivering energy by

Once the qualitative evaluation criteria were agreed and draft evaluation sheets were prepared for each criterion, the next step was to include a description of the requirements for proposals to be classified in each of the scoring categories (or rankings) for each evaluation criterion. For most of the criteria, each proposal would be classified into one of three scoring categories based on meeting specified standards: Superior, Preferable, or Meets Minimum Standards. Once the drafts for each criterion were prepared, members of the Qualitative Evaluation Team and the IE reviewed the write-ups. The IE suggested modifications with the objective of providing more clear resolution between different scoring categories to facilitate the evaluation and scoring of bidder proposals.

Other issues addressed included: (1) the total number of points to allocate to each criterion based on the maximum 25 qualitative points; and (2) the amount of points to allocate based on the scoring category for each criterion. For the most part, if a proposal is deemed to meet the requirements listed for the Meets Minimum Standards category, the Bidder would receive 0 points. Proposals rated as Superior would achieve the maximum score for that criterion. Proposals deemed to be in the Preferable category were generally awarded points in the middle of the range, as specified in the qualitative evaluation protocol.

The Qualitative Evaluation Protocol was completed prior to the initiation of proposal review and evaluation.

d. Stage 3 Evaluation Protocol

The Evaluation Team developed a Stage 3 evaluation protocol that extrapolated from the RFP provisions applicable to Stage 3 of the evaluation (RFP sections 2.3.2 and 2.4). First, portfolios totaling approximately the annual procurement target of 9.45 TWh would be developed based on the higher-ranked bids from the Stage 2 evaluation. These portfolios would then be subject to the same quantitative evaluation as the large projects in Stage 2. The Evaluation Team would then make decisions regarding the selection of the project portfolio with an annual MWh amount that approximated the annual procurement target. The criteria for selecting project portfolios were described:

- Stage 2 evaluation criteria; other criteria might also be considered, such as production cost savings;
- Cost-effectiveness of the portfolios and impact on the Commonwealth's policy goals, including GWSA goals;
- Risks associated with project viability of the proposals;

the end of 2020 or could provide reliability benefits (RFP sections 2.3.2.iii and 2.3.2.v) was part of the qualitative evaluation protocol, but the scoring for it largely depended on outputs from the quantitative evaluation.



- Any risks that may be associated with proposed transmission agreements not fully captured in the Stage 2 evaluation;
- Any benefits to customers not fully captured in the Stage 2 evaluation;
- Any other factors to ensure that a proposal provides the greatest impact and value consistent with the stated objectives and requirements of 83D.

Finally, the Evaluation Team approved a scope of work for TCR's subcontractor Mott & McDonald, which would review the transmission proposals associated with generation bids in terms of reasonableness of cost estimates and schedule.

C. Evaluation of the Bids

This section of the report addresses the Evaluation Team's evaluation of proposals at each of the three stages of the evaluation process.

1. Threshold Evaluation

A working group was formed to review the various project proposals for threshold and eligibility requirement issues. One bid was disqualified at the outset because it was received by the Evaluation Team a day late.⁴⁸

The threshold working group conducted a preliminary analysis of bids that either appeared not to meet eligibility or threshold requirements or where clarification was required from the bidder. There were also questions where it was not clear whether there was a failure to meet threshold requirements or where more information was needed simply to facilitate the qualitative or quantitative evaluation of the proposal. This led to the Evaluation Team sending letters seeking clarification or additional information from many of the bidders. This was consistent with the RFP provisions which allowed the Evaluation Team to permit bidders to cure deficiencies in their bids.

During any stage of the procurement process, if the Evaluation Team determines that any proposal is deficient and missing applicable information needed to continue the evaluation process, the Evaluation Team will notify the respective bidder and permit the bidder a reasonable opportunity to cure the deficiency and/or supply the missing information.⁴⁹

The letters to bidders covered a wide range of questions, such as whether the bidder had submitted interconnection studies that satisfied RFP requirements (RFP section 2.2.1.9), complied with RFP pricing requirements (Section 2.2.1.4), and demonstrated sufficient site control (Section 2.2.2.1). In addition, letters were sent to bidders of generation with associated transmission regarding the specific threshold

⁴⁸ The bidder was [REDACTED]. The bid fees were returned because no evaluation of the bid was conducted.

⁴⁹ RFP section 2.1.

requirements applicable to transmission proposals (RFP Sections 2.2.1.4.i and 2.2.2.6) and the more general requirements applicable to all bids.

The Evaluation Team reviewed bidder responses to the questions. In some cases, the responses were unclear, and follow-up questions were issued to which the bidders responded. Many of the Evaluation Team questions pertained to the RFP requirements applicable to interconnection studies:

All projects submitted by bidders must have filed an interconnection request with ISO-NE. Projects that have received their I.3.9 approval from ISO-NE must identify that approval and include such documentation in their proposal. Proposals that do not have I.3.9 approval from ISO-NE must include technical reports or system impact studies that approximate the ISO-NE interconnection process, including but not limited to clear documentation of study technical and cost assumptions, reasoning, and justification of such assumptions. All studies must assume the project will interconnect using the Capacity Capability Interconnection Standard, must use the current ISO-NE interconnection process (including network impact scenarios from multiple projects interconnecting), and must also detail any assumptions with respect to projects that are ahead of the proposed project in the ISO-NE interconnection queue and any assumptions as to changes to the transmission system that differ from the current ISO-NE Regional System Plan.⁵⁰

All bids were also required to include a commitment to interconnect to the ISO-NE transmission system at the Capacity Capability Interconnection Standard.

The Evaluation Team consulted with ISO-NE representatives regarding the status of projects in the interconnection queue, ISO studies, and applicable ISO rules and practices.

All in all, 17 of the 53 project proposals submitted were determined not to satisfy eligibility and threshold requirements. The great majority of them—13 in all—were determined not to satisfy the interconnection and delivery requirements set forth in Section 2.2.1.9 of the RFP (and/or the commitment to interconnect at CCIS under Section 2.2.1.8). The reasons varied by project, such as not filing an interconnection request with the ISO at the time of bid, withdrawing interconnection requests, not including all costs to deliver to the delivery point, no ISO CCIS study or finding and no bidder CCIS study supplied, studies provided or being conducted that did not meet ISO standards, and location-specific problems that do not allow the CCIS to be satisfied without extensive upgrades that were not proposed by the bidder. Some bids had multiple interconnection-related deficiencies.

One bid from existing hydroelectric facilities in ISO-NE without any proposed expansion was determined not to supply incremental hydroelectricity, as required by RFP section 2.2.1.3.i. Another bidder failed to provide required financial information and failed to demonstrate financial viability of the project (see RFP sections 2.2.1.10 and 2.2.2.2). Finally, there was a failure to demonstrate site control with respect

⁵⁰ RFP section 2.2.1.9.

to two project proposals. The proposals that were found not to meet eligibility/threshold requirements, and the basis for determining that requirements were not satisfied, are summarized in Appendix C.

There were several other projects that had substantial questions as to whether they satisfied threshold requirements. However, the Evaluation Team did not reach consensus on these matters, so these projects were evaluated quantitative and qualitatively in the Stage 2 evaluation. None of these projects, however, were highly competitive, and none were selected.

Finally, the IE, pursuant to its contract with DOER, retained a forensic accounting firm, Meaden & Moore, to ascertain whether any bidder failed to disclose any affiliate relationships with the Distribution Companies, as required under RFP section 2.2.1.5. Meaden & Moore identified participation by EDC affiliates in three sets of project proposals—Northern Pass, an Eversource affiliate, involving Quebec hydro-only and hydro and wind bids and proposed transmission in New Hampshire; Granite State Power Link, a National Grid affiliate, involving Quebec wind-only bids and proposed transmission in New Hampshire; and NRPP Bid A, involving a National Grid affiliate, with wind and solar energy and firming hydro from New York. In each case, the Distribution Company affiliate was proposing to build new transmission. After review, Meaden & Moore did not find any bidder that failed to disclose an affiliate relationship to any of the Distribution Companies.

2. Stage 2 Quantitative and Qualitative Evaluation

a. Quantitative Evaluation

The Evaluation Team first commenced the quantitative and qualitative evaluation of small projects—defined (for this purpose) as below 300 MW in installed capacity—that passed an initial threshold evaluation screening. These projects were generally easier to evaluate than the larger projects—most of which involved associated new transmission in the project proposals. As more small projects were determined to have passed the threshold evaluation screening, they were passed on to TCR for quantitative evaluation and to the Qualitative Evaluation Team for qualitative evaluation.

The larger projects with associated transmission raised a number of issues for the evaluation. Some of these issues flowed from the lack of a pro forma transmission service agreement (“TSA”) that was provided to bidders (in contrast, PPA bidders were required to bid to a pro forma PPA) and the less restrictive threshold requirements applicable to transmission pricing compared to those applicable to PPAs.⁵¹ These issues included:

- Some proposed TSAs did not include provisions that precluded EDC liability for payments (either for transmission service or abandonment costs) absent non-appealable Department and FERC

⁵¹ The stated reason the Distribution Companies did not include a pro forma TSA in the RFP package was due to a desire to provide bidders with more flexibility. Other likely reasons are the relative lack of EDC experience in this area in a competitive bidding context and, perhaps, the difficulty they would have had on reaching agreement on a pro forma TSA within the timeframe of the RFP process.

approvals (the pro forma PPA precluded EDC liability for charges unless and until a non-appealable Department order approving the PPA was obtained);

- Some proposals contained proposed project schedules and/or pricing that were based on unrealistic assumptions regarding the timing of project selection in this solicitation, contract execution, and Department approvals (including dates that were more accelerated than those set forth in the RFP);
- Some transmission proposals contained either cost-of-service or price adjustment provisions that required estimation of items such as future levels of interest rates, commodity prices, and/or exchange rates;
- There were many clarification questions regarding complex provisions of proposed TSAs and their impact on risk allocation between the transmission owner and the EDCs;
- There were questions regarding whether some TSAs satisfied threshold requirements applicable to TSAs (such as the provisions in section 2.2.2.6 of the RFP regarding cost containment, abandonment cost, and transmission costs in the absence of energy).

The Evaluation Team sent several series of questions to the bidders with associated transmission proposals to address a variety of issues. Typically, the questions involved requests to modify the proposed TSA to conform with threshold requirements or to provide important clarifications.⁵² Bidders were also required to provide justification, where applicable, for their estimated costs associated with proposed cost-of-service provisions or those that contained price adjustments based on future costs. This process generally led to improvements in bids from the standpoint of conformance with threshold requirements, risk allocation and clarity. However, it took a substantial amount of Evaluation Team time and attention. The IE was highly involved in this process to assure that the evaluation was fairly and reasonably conducted, especially since three transmission bidders were EDC affiliates. The IE focused in particular on correctly interpreting the transmission proposals and assuring that they would be properly evaluated in the quantitative and qualitative evaluation from an EDC/EDC customer cost and cost risk perspective. Requiring transmission bidders to agree not to charge the EDCs, including for abandoned plant cost recovery, absent non-appealable FERC and Department orders approving the TSA addressed a concern raised by the IE in its RFP design report. In terms of the quantitative evaluation, the IE raised concerns regarding whether some of the costs for some transmission bids were being properly evaluated.

Northern Pass, an Eversource affiliate, had proposed [REDACTED] transmission rates [REDACTED]
[REDACTED]
[REDACTED]
[REDACTED] NPT's estimated cost of debt was stated as [REDACTED]

⁵² As one example, transmission bidders were asked to modify proposed TSAs, where necessary, to clarify that EDCs would not be liable for any charges or for abandonment cost recovery absent non-appealable Department and FERC approvals of the pertinent agreements.

percent [REDACTED] which appeared quite low. The IE drafted a question regarding the basis for this forecasted interest rate. NPT's response stated:

[REDACTED]
[REDACTED]
[REDACTED]

[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]

[REDACTED]
[REDACTED]
[REDACTED]

[REDACTED] At the time the bid was being evaluated (December 2017/January 2018), long-term interest rates had risen significantly from the time of bid submittal and were forecast to increase substantially over the next [REDACTED] years [REDACTED]. The IE raised the question to the Evaluation Team as to whether NPT's estimated cost of long-term debt of [REDACTED] was reasonable for use in the quantitative evaluation.

On a conference call in January 2018, TCR, members of the Evaluation and the IE met to discuss what interest rate to use in the quantitative evaluation of the NPT proposals (hydro and hydro and wind). Shortly before the call, National Grid had proposed a 5.00 percent interest rate, based on use of a 20-year Treasury rate representing the term of the proposed contract, a forecasted interest rate of 3.85 percent using the Blue Chip Financial Forecast, Long-range consensus estimate, published on December 1, 2017, and a credit adder of 1.15% based on a review of certain Eversource debt offerings. After discussion, TCR proposed to use a 4.55% for the Stage 2 (as well as Stage 3) evaluations based on use of a 10-year Treasury (reflecting a 20-year term and a 10-year weighted average life given that Treasury bonds pay out principal only at the end of the term), a forecasted interest rate of 3.60 percent based on the same consensus Blue Chip Financial Forecast referenced by National Grid, and a credit adder of .95 percent [REDACTED]—this was later reduced to 4.45% based on a reduced credit

⁵³ NPT Confidential Bid pp. 5-6 – 5-7.



adder due to a credit rating increase.⁵⁴ TCR, the Evaluation Team Consultant, National Grid, and the IE supported use of the 4.45% interest rate for use in the Stage 2 and Stage 3 evaluations.⁵⁵

At this time, Eversource opposed revising the quantitative evaluation—which was based on the [REDACTED] percent interest rate—to incorporate the higher interest rate proposed by TCR. Eversource argued that the bidder’s estimated interest rate should be used in the evaluation because using another interest rate would be “changing the bid.” At a Steering Committee meeting, the IE (and National Grid) thought that the decision was made to use the 4.45% interest rate, but there was apparently a lack of clarity. Subsequently, DOER stated that the higher interest rate should be run as a sensitivity in Stage 3 and not modify the Stage 2 results, which is the way the results were reported. Ultimately, as will be discussed, the selection decision was based on the quantitative evaluation using the 4.45% interest rate assumption.

The IE also raised a concern regarding a second transmission bid. One transmission bidder had proposed fixed transmission rates but had indicated by way of footnote that it was interested in discussing a [REDACTED] price adjustment provision in its TSA if it was selected for negotiations. The Evaluation Team asked the bidder to confirm that the proposed price was a fixed price or to specify any associated price adjustment provisions. The bidder responded that it was seeking a price adjustment for changes in specified [REDACTED] but that it was also proposing an alternative fixed-charge rate, albeit at a higher level than originally bid. The Evaluation Team decided to evaluate both proposals. The IE assisted in formulating questions that would obtain information from the bidder with enough specificity to facilitate TCR’s review of the pricing alternative with the proposed [REDACTED] price provision.

On December 22, 2017, the same day that President Trump signed into law the Tax Cuts and Jobs Act, which, among other things, reduced the corporate income tax rate from 35% to 21%, the Evaluation Team decided to give bidders the opportunity to refresh pricing based on the new lower tax rates, with the expectation that this could lead to significantly lower prices for some bids. In letters to all bidders, bidders were given until January 3, 2018 to propose lower prices if they chose to do so. A number of bidders, including several of the transmission bidders, submitted reduced prices.⁵⁶ Since the Stage 2 evaluation was then in the process of being finalized and the impact of the proposed price reductions appeared to be relatively modest, the quantitative evaluation of the revised bids was not included in the final Stage 2 evaluations but was included in the Stage 3 evaluations.

⁵⁴ [REDACTED]
[REDACTED].

⁵⁵ This same issue also affected the evaluation of the [REDACTED] bid, which had a price adjustment provision based on the 10-year Treasury note rate prevailing at the time [REDACTED].

⁵⁶ The effect on solar and wind projects of the new tax law was not clear because of the potential impact of the legislation on the financing value of investment tax credits and production tax credits. Many wind and solar developers did not provide reduced pricing.

b. Qualitative Evaluation

After the initial threshold evaluation review, members of the Qualitative Evaluation team as well as the IE reviewed and scored the proposals. Weekly meetings of the team were held to walk through and discuss the basis for scoring each proposal within each evaluation criterion. During the conference calls to discuss specific proposal scoring, members of the Qualitative Evaluation Team would each identify their score and the basis for the score awarded. If other team members scored the proposal differently, the members of the team would discuss the basis for scoring and attempt to reach a consensus. The IE raised issues if the scoring seemed inconsistent or skewed. In most cases, the IE identified his score and the basis for scoring if relevant to the discussion. The result of the qualitative evaluation was that team members generally reached resolution on a score for each of the criterion for each proposal, and the IE having evaluated and scored each proposal, was satisfied that the results were fair and objective.

There were a number of exceptions, particularly toward the end of the Stage 2 evaluation process, where the evaluation focused on the [REDACTED] categories. For example, Eversource proposed that NPT get a maximum score for the [REDACTED] category and proposed that certain competing transmission bids receive lower scores despite the fact [REDACTED]

[REDACTED] The other members of the Evaluation Team and the IE rejected this position, and the final scores, in the IE's opinion properly reflected the [REDACTED] inherent in these proposals.

Similarly, Eversource proposed that NPT receive the superior score for [REDACTED] while competing bids receive the preferable (i.e., middle) score. Other members of the Evaluation Team and the IE did not accept this position, and NPT was given a preferable (i.e., middle) score.

Also, Eversource had argued that NPT [REDACTED] and, hence, deserved a superior score for [REDACTED], while other members of the Evaluation Team and the IE evaluated NPT as having [REDACTED], deserving only a preferable (i.e., middle) score. After discussion, the Evaluation Team gave NPT a preferable (middle) score in this category; a competing project that had already obtained its [REDACTED] was given a superior score.

[REDACTED]

On these matters, the IE advocated against compromising with Eversource where the result could not be justified on the merits. In the end, the IE was satisfied that the qualitative evaluation of the NPT bids as well as other bids was fair and objective and not unduly influenced by affiliate relationships.

c. Stage 2 Scores and Ranking

Summary results for large projects and small projects in terms of the quantitative evaluation, the qualitative evaluation, and total scores for Stage 2 are set forth in Appendix D and Appendix E respectively. These were compiled by TCR in early January 2018 and are reflected in Appendix 1 of the TCR Report. As indicated previously, these scores did not incorporate any proposed price reductions associated with the new corporate tax law and reflected NPT's estimate of [REDACTED] % for the long-term cost of debt for this proposal.

3. Stage 3 Evaluation of Proposal Portfolios

At the beginning of Stage 3 of the evaluation, the Evaluation Team developed a number of project portfolios that approximated the annual procurement target of 9,450,000 MWh based on the rank order of projects at the end of the Stage 2 evaluation. In addition, the Evaluation Team developed a number of sensitivity analyses for TCR to model.

A number of proposals were of sufficient size to be their own project portfolios:

- NECEC Hydro (HRE hydro supply)	Portfolio 6	9.55 TWh
- [REDACTED]	Portfolio [REDACTED]	[REDACTED] TWh
- [REDACTED]	Portfolio [REDACTED]	[REDACTED] TWh
- [REDACTED]	Portfolio [REDACTED]	[REDACTED] TWh
- [REDACTED]	Portfolio [REDACTED]	[REDACTED] TWh

Other portfolios involved combinations of large and small project proposals:

[REDACTED]	Portfolio [REDACTED]	[REDACTED] TWh
[REDACTED]	Portfolio [REDACTED]	[REDACTED] TWh
[REDACTED]	Portfolio [REDACTED]	[REDACTED] TWh
[REDACTED]	Portfolio [REDACTED]	[REDACTED] TWh
[REDACTED]	Portfolio [REDACTED]	[REDACTED] TWh





TCR ran each of these portfolios in its ENELYTIX model and workbooks using the updated bids. The same quantitative evaluation methodologies were used as in Stage 2, although the revised bids with lower prices based on the tax law changes were evaluated. A quantitative scoring was assigned based on 75 for the portfolio with the highest levelized total net benefits per MWh and a proportionately lower score for other portfolios based on their evaluated net benefits. Qualitative scores were derived by weight averaging the qualitative scores for each project proposal comprising the portfolio.

The highest ranking proposals were NECEC Hydro (Portfolio 6), combinations of NECEC Hydro and [REDACTED], and NPT Hydro. The Evaluation Team decided to run scenarios for NPT Hydro and NECEC Hydro involving one-year delays in COD for these projects and considered different interest rate assumptions for NPT (with a range from the bidder estimate of [REDACTED] % to the TCR recommended rate of 4.45%). Because the top-ranked projects in the portfolio evaluation involved NPT Hydro and NECEC Hydro, the Stage 3 evaluation focused on the respective strengths and weakness of these two project proposals. Since both of them involved similar supplies of hydropower from Hydro Quebec's affiliate, HRE, the evaluation focused on the different transmission proposals and their potential benefits, risks and costs, especially those that may not have been fully incorporated into the quantitative and qualitative evaluation. The next highest ranked project was [REDACTED]

[REDACTED]. The proposed project, while more expensive than either NECEC or NPT, [REDACTED]. The Stage 3 evaluation, as conducted and compiled by TCR, with project rankings based on the real levelized \$/MWh metric and with the ranking for the NPT project based on the assumed 4.45% interest rate, is set forth in Appendix F to this report (which also includes the results of sensitivity runs). During the Stage 3 deliberations, TCR also presented a ranking with NPT's bidder supplied interest rate assumption. Under either set of assumptions, the NECEC Hydro proposal had a higher rank than the NPT Hydro proposal.

DOER put together a table based on the TCR evaluation results, but with alternative scores and ranking using net present value results in addition to scoring and ranking using the real levelized \$/MWh metric. [REDACTED] A summary of that table with scoring based only on the \$/NPV metric is set forth in Appendix G to this report.⁵⁸ Using the alternative net present

⁵⁸ The scoring for portfolios in Stage 3 based on the real levelized \$/MWh metric is in Appendix F.

value metric, the NPT proposal had higher scores and a higher ranking (taking into consideration the qualitative evaluation) than the NECEC proposal.⁵⁹

During the Stage 3 deliberations, Eversource proposed that the Evaluation Team give preference to projects that deliver earlier than others, stating that the quantitative and qualitative evaluation did not give sufficient value to this attribute and that early delivery can protect against the risks of an early onset polar vortex-type winter. Eversource also proposed that projects whose price may be too low to be financed or were at a relatively early stage of development should be assessed a contingency cost representing a replacement cost if the project can't be built. The IE thought that the Eversource proposal was insufficiently balanced and expressed the opinion that the proposed contingency adder was not supportable or even workable in the context of the solicitation.

The IE provided guidance to the Evaluation Team regarding the appropriate scope of the Stage 3 evaluation and the basis for selection of project proposals.

- The starting point for the Stage 3 evaluation should be the results of the Stage 2 evaluation and the portfolio evaluation results produced by TCR in Stage 3
- In the IE's opinion, the quantitative evaluation and scoring for the NPT Hydro proposal should be based on the 4.45% interest rate recommended by TCR, the Evaluation Team Consultant
- The RFP allows in Stage 3 for the EDCs and DOER to use "a reasonable degree of considered judgment" based on the criteria set forth in the RFP
- Matters for consideration include:
 - Cost-effectiveness of proposals
 - Impact on the Commonwealth's policy goals, including GWSA goals
 - Risks associated with the viability of projects
 - Any benefits that are valid in the context of this RFP but not fully captured in the evaluation
 - Risks associated with transmission costs not fully captured in the evaluation.⁶⁰

⁶⁰ The IE also noted that the quantitative evaluation of the NECEC proposals did not appear to take into consideration Hydro Quebec's ability to deliver 110 MW of energy through the NECEC line for its own account above the 1090 MW of deliveries to the EDCs under the proposal. The IE expressed that it wasn't certain what the impact of incremental Hydro Quebec deliveries would be because there could be a reduction in the LMP at the delivery point in Maine, which would reduce direct benefits, but this could be offset or exceeded by indirect benefits, such as reductions in LMPs for Massachusetts EDC customers and GHG reductions. The IE raised the question whether an additional model run should be conducted. An additional model run, at the request of Eversource, was conducted by TCR after the Stage 3 evaluation and bid selection, which showed an increase in net benefits (the indirect benefit improvement outweighed the reduction in direct benefits), which would not have affected TCR's rank ordering of the bids. The results of this additional model run are summarized in Appendix F.

DOER pressed the Evaluation Team to reach a selection decision in accordance with the RFP schedule, which called for selection by January 25, 2018. On a conference call, the Evaluation Team discussed risk issues and other evaluation matters pertaining to a number of higher-ranked projects.

Due to time limitations, the Stage 3 evaluation focused on the two highest ranked mutually exclusive projects, NECEC Hydro and NPT Hydro. Aside from the NPT interest rate issue previously discussed, the IE suggested that the Evaluation Team confer with ISO-NE regarding potential and likely outcomes of the Maine Cluster process with respect to NECEC. A call was held between representatives of the ISO and the Evaluation Team, which was very informative.

D. Bid Selection

1. Initial Selection

At a Steering Committee meeting held on January 18, 2018, the EDCs were asked which bid or bids they recommended for selection. Under 83D, if the EDCs unanimously agreed on the same bidder as the winning bidder, that bidder would be selected. Without unanimous agreement, DOER, after consulting with the IE, would make the final binding decision.

Eversource recommended the NPT hydro proposal. National Grid recommended the NECEC hydro proposal. The two EDCs provided reasons in support of their recommended selections. Unitil indicated that it had not yet reached a decision internally in order to make a recommendation. DOER asked the EDCs to meet separately to see if they could reach a consensus. If a consensus could not be reached, DOER asked each EDC to put their recommendations and supporting rationale in writing and to circulate their position papers the following day, which the EDCs did.

Eversource's rationale for selecting NPT was based in part on having the highest total net benefits, stated as a range of [REDACTED], and that those benefits would be delivered at the earliest date of the highest ranked proposals—prior to the end of 2020. Eversource stated that the [REDACTED] percent interest rate for NPT was "likely optimistic given changes in interest rates since the bids were submitted in July 2017," and that "[w]ithin the range selected by the Evaluation Team of [REDACTED] and 4.45 percent (high), NPT is the highest scoring project in terms of Total Net Benefits to customers" (using the NPV \$ metric). Eversource argued that net present value results are a better economic indicator of value to Massachusetts customers than real levelized \$/MWh for projects of similar size. On a variety of other factors, such as being more advanced in the permitting and interconnection process, Eversource rated NPT as a superior choice compared to NECEC.

Unitil rated NECEC and NPT as being similar with respect to quantitative net benefits but viewed NPT as a more mature project posing much less viability risk. In addition, it viewed the earlier projected on-line

date of NPT as creating more value for Massachusetts customers. Unitil recommended the selection of NPT.

In explaining its rationale for selecting NECEC, National Grid stated that using the real levelized \$/MWh metric, the NECEC project's net benefits of \$40.02/MWh was superior to that of NPT's \$[REDACTED] MWh and the total score was higher, 90.63 points to [REDACTED], using the 4.45% interest rate supported by the Evaluation Team consultant and the IE.⁶¹ Even using the total \$ NPV metric, the NECEC project—\$3.9 billion—was higher than NPT's \$[REDACTED] billion. Also, the levelized \$/MWh cost of the NECEC contracts were lower—\$59/MWh to [REDACTED]/MWh. National Grid stated that qualitative differences in the proposal were already captured in the qualitative scoring, with NPT scoring [REDACTED] higher. National Grid stated that NPT Hydro's claim that it will meet a December 2020 on-line date was highly doubtful, given that it would have to place [REDACTED] million at risk to do so, and that its [REDACTED].⁶² National Grid also stated that NECEC's fixed price bid provided less cost risk for customers than NPT's bid.

Given that the EDCs did not agree, the selection decision moved to DOER. On January 18 and January 24, DOER met with the IE in connection with the consultative process prescribed by 83D prior to a final DOER selection decision. The IE provided similar advice to DOER as it had given to the Evaluation Team as a whole regarding guidelines for selection. The IE advised that the starting point of the evaluation should be the quantitative and qualitative scoring under Stage 2 and Stage 3, with the quantitative evaluation to be based on the 4.45% interest rate for NPT rather than the bidder estimate of [REDACTED]%. Further, the IE suggested that the decision should be between the two highest ranked projects—NECEC Hydro and NPT. Beyond that, the IE suggested that DOER could consider a number of factors allowed to be considered in Stage 3 under the RFP and the evaluation protocol, which may include relative value regarding meeting GWSA goals, project viability, and ratepayer risk and benefit issues not fully captured in the Stage 2 evaluation.

On January 25, 2018, DOER announced its selection of NPT Hydro as the winning bid. DOER provided a memo to the IE setting forth the basis for its decision. First, DOER noted that its decision was based on

⁶¹ National Grid stated that it provided data supporting a debt financing rate of 5.0%. National Grid noted that NECEC had used a 5.0% percent interest rate assumption to formulate the NECEC transmission rate proposal and that NPT had used a [REDACTED] interest rate assumption in its bid in the multi-state Section 83A solicitation. National Grid also asserted that NPT's assumed debt financing rate of [REDACTED] percent was dismissed by the Evaluation Team as unrealistic and a debt financing rate of 3.6 percent proposed by Eversource was also unrealistically low.

The 3.6 percent interest rate was based on the use of current forward prices for future interest rates quoted by Bloomberg, specifically, an indication of what traders would commit to currently (January 24, 2018, in this case) with respect to interest rates several years in the future, rather than a forecast of what interest rates are likely to be several years in the future [REDACTED]

[REDACTED]

⁶² [REDACTED]



an assumed 4.45% interest rate for NPT, rather than the bidder supplied estimate of [REDACTED] DOER also noted that the two projects utilize the same Hydro Quebec generating resources and would deliver similar quantities of energy through two new alternative transmission lines. DOER stated that after careful consideration it believed that the NPT project would provide the greatest value to Massachusetts customers based on a number of reasons, including the following:

- A proposed in-service date two years earlier than NECEC's, supporting a stronger likelihood of an earlier in-service date
- More progress in the permitting and interconnection processes, providing additional certainty that the project will be constructed earlier
- Similar net benefits to Massachusetts ratepayers⁶³
- By coming online earlier, a likelihood of additional and earlier GHG tonnage reduction assisting the Commonwealth in meeting GWSA requirements
- Providing insurance benefits against winter price spikes and gas supply constraints at an earlier time than NECEC, mitigating significant winter reliability concerns.

While both NPT and NECEC were expected to provide cost-effective clean energy, DOER concluded that NPT's greater certainty for an earlier in-service date gave it the advantage as the winning bid in light of the urgent need to meet GWSA goals, as well continuing concerns for near-term winter reliability stresses on the regional electric grid exacerbated by pending generator retirements.

Based on this decision, the EDCs sent a letter to NPT and HRE notifying them that the NPT Hydro proposal was selected for contract negotiations.

On January, 31, 2018, DOER recommended, and the EDCs agreed, that the IE continue to monitor the next phase of the procurement, including contract negotiations. At the time, the expected contract negotiations were with Northern Pass, Eversource's affiliate, as well as HRE. This was beyond the IE's original scope of work, but resulted in an additional level of oversight.⁶⁴

⁶³ In its memo to the IE, DOER stated that "in terms of net benefits to Massachusetts ratepayers, the projects are within [REDACTED] % of each other, both delivering approximately [REDACTED] in net benefits to ratepayers." Given benefits of [REDACTED] billion for NPT (using the assumed 4.45% cost of long-term debt) and \$3.904 billion for NECEC, the difference is actually [REDACTED] %. However, the essential point is that DOER did not view the difference in quantitative benefits between the two projects as being sufficiently large to rely on in making its decision (absent other considerations) and that qualitative advantages for NPT (as further described in the memo) were determinative.

⁶⁴ Peregrine had originally recommended that monitoring of contract negotiations be included in the IE's scope of work, which is common for independent evaluators, but this was not included due to objections by the EDCs. Peregrine monitored the contract negotiations, which were mostly conducted on conference calls. As part of the arrangement with DOER and the EDCs, Peregrine was not provided with drafts of contracts or email exchanges with the bidders, but was allowed to review contract drafts by WebEx. The IE was also invited to internal calls with the EDCs and was provided with the opportunity to comment or ask questions on those calls.

2. NPT Denied Siting Approval; Evaluation Team Selects Conditionally Selects NECEC

On February 1, 2018, one week after NPT was selected as the winning bidder, the New Hampshire Site Evaluation Committee voted unanimously to reject Northern Pass' application for siting authority.⁶⁵ Without the NHSEC's approval, Northern Pass would not have the authority to construct its proposed project.

The next day, DOER sent a letter to the EDCs requesting that the EDCs send a letter to Northern Pass seeking information on the status of the project in light of the NHSEC's recent action and what the project's plans were to address the denial.⁶⁶ DOER also sought an early meeting with the EDCs and the IE to discuss the matter. On February 5, the EDCs sent a letter to NPT, asking whether and how the NHSEC decision affected Northern Pass's bid, including the proposed commercial operation date, and to describe the company's plans to reverse the NHSEC decision or otherwise obtain NHSEC approval. NPT responded that it would seek rehearing of the NHSEC decision and appeal it, if necessary. [REDACTED]

Soon thereafter, the EDCs and DOER met to consider NPT's responses and how to proceed. National Grid proposed that negotiations be commenced with NECEC, while negotiating at the same time with NPT, thereby giving Northern Pass some time to go through the NHSEC rehearing process. Eversource and Unitil recommended staying the course with NPT. The result of the conference call was that DOER would make a final binding decision regarding the course of action if the EDCs could not agree. A second conference call was held several days later.

DOER expressed the view that the fact of NPT's permit denial was very problematic and that the focus should be on the Massachusetts RFP timetable for decision, with a March 27, 2018 date for contract execution, not the timetable in the NHSEC process. The EDCs reiterated their position from the prior meeting.

The IE suggested that the Evaluation Team consider [REDACTED] as well as NECEC in deciding on an alternative project/project portfolio with which to negotiate, stating that while [REDACTED] was ranked below NECEC, it was ranked only slightly lower than NPT and it had a higher qualitative evaluation score because [REDACTED]. After a brief discussion, the EDCs unanimously stated their preference for NECEC over [REDACTED] due to NECEC's lower cost.

⁶⁵ Transcript of February 1, 2018 hearing at 24-26, NH SEC Docket No. 2015-06, https://www.nhsec.nh.gov/projects/2015-06/transcripts/2015-06_2018-02-01_transcript_delib_day3_pm.pdf.

⁶⁶ https://macleanenergy.files.wordpress.com/2018/02/letter-from-doer-asking-edcs-for-decision_02022018.pdf.

With disagreement among the EDCs regarding the terms under which negotiations would proceed with both NPT and NECEC (as the alternative selected project),⁶⁷ DOER decided that NECEC should be given the opportunity to negotiate a contract while negotiations also proceed with NPT, with discontinuance of contract negotiations with NPT and termination of its conditional selection if NPT did not obtain NHSEC approval by March 27, 2019. NECEC and NPT were asked to accept the terms of their conditional selections, which they did.

Following execution of confidentiality agreements, the two sets of negotiations commenced: a TSA with NPT with an associated PPA with HRE; and a TSA with CMP and an associated PPA with HRE. Negotiations and preparation for them were affected by several snowstorms, which slowed the process.⁶⁸

Negotiations proceeded for several weeks in March with both NPT and NECEC. On February 28, NPT had filed a request for rehearing with the NHSEC, which had been objected to by multiple parties. On March 13, the NHSEC ruled that it would issue a final written order (it had not yet memorialized its oral decision into a written order but had previously stated it would do so by March 31), and allowed another 10 days (under its rules) for any party to seek rehearing of its order.⁶⁹ There was no indication of any intent to reverse the unanimous oral decision denying NPT's application.

The 83D Steering Committee met on March 26, 2018. Prior to the meeting, DOER circulated draft letters for review by Steering Committee members (with NECEC and NPT as addressees), which stated that if NPT received its NHSEC permit by March 27, the EDCs would continue negotiations with NPT and terminate those with NECEC; alternatively, if NPT did not receive its NHSEC permit by that date, the EDCs would terminate NPT's conditional selection and continue negotiations with NECEC. At the ensuing Steering Committee meeting, National Grid supported terminating negotiations with NPT and continuing negotiations with NECEC. Eversource opposed terminating negotiations with NPT, indicating that the bidder should be given more time to reverse the denial and obtain the required permit, and that negotiations should continue with both NPT and NECEC, with a decision on which deal to execute to be made at the end of the negotiations. Unitil stated that given the difference in opinion between Eversource and National Grid, it was up to DOER to make the final selection decision.

The IE agreed that the decision at hand was a selection matter, and, under 83D, it was a matter for DOER to decide. The IE expressed the view that the decision implicit in DOER's draft letters was consistent with the prior Steering Committee decision. The IE also indicated that the likelihood of NPT

⁶⁷ The different approaches are reflected in letters from National Grid to DOER dated February 12, 2018 and from Eversource to DOER dated February 14, 2018.

⁶⁸ This was primarily due to EDC personnel needing to perform storm duty.

⁶⁹ Order Suspending Decision, Docket No. 2015-06. https://www.nhsec.nh.gov/projects/2015-06/orders-notices/2015-06_2018-03-12_order_suspend_decision.pdf.

being able to reverse the NHSEC decision and obtain its permit within any reasonable timeframe was remote. Further, the IE expressed the view that Eversource's continuing effort to keep NPT in the running represented favoritism or at least the appearance of favoritism toward its affiliate. DOER indicated that given the situation it was virtually impossible for NPT to make its scheduled 2020 online date, which was a major reason for its selection, and the unanimous permit denial made it very questionable whether the project could be built within the scope of its bid or at all. As a result, DOER decided that if NPT did not receive its permit by March 27, its conditional selection would be terminated and that contract negotiations would continue with NECEC. Subsequently, the EDCs terminated contract negotiations with NPT.⁷⁰

IV. Monitoring the Contract Negotiation Process

After the NECEC 100% hydro bid became the sole project with which the EDCs were negotiating, the negotiations proceeded in earnest with respect to the proposed PPA, the proposed TSA, and how these agreements interacted with each other. The IE monitored the negotiations and reviewed them from several perspectives:

- Were the resulting product of the negotiations (PPA and TSA) no less advantageous from an EDC customer standpoint than the bids submitted by CMP and HRE (such that the contracts as negotiated would be consistent with the bids as evaluated)?
- Were the resulting product of the negotiations (PPA and TSA) conforming with the requirements of the RFP?
- Did the EDCs negotiate in good faith and treat the winning bidders fairly?
- Was there any evidence of undue discrimination against the NECEC bid sponsors because they were not affiliates of any of the EDCs?

Since CMP or HRE are not affiliates of any of the EDCs, there was no issue of preferential treatment of an affiliate.

These matters are addressed in Section V.D of this report.

⁷⁰ On March 30, 2018, the SEC issued its written order denying NPT's application for site authority. https://www.nhsec.nh.gov/projects/2015-06/orders-notices/2015-06_2018-03-30_order_deny_app_cert_site_facility.pdf. Subsequently, NPT filed for rehearing, which the NHSEC denied at a hearing held on May 24, 2018, https://www.nhsec.nh.gov/projects/2015-06/transcripts/2015-06_2018-05-24_transcript_rehearing_deliberations_am.pdf, and memorialized in a written order issued on July 12, 2018, https://www.nhsec.nh.gov/projects/2015-06/orders-notices/2015-06_2018-07-12_order_mtn_rehearing_mtn_strike.pdf.



V. Analysis of Solicitation, Bid Evaluation, Selection and Contract Negotiation Process

In this section of the report, we review the fairness of the bid evaluation framework and the evaluation and selection of bids. We do this in the context of the 83D criteria of an “open, fair and transparent solicitation and bid selection process that is not unduly influenced by an affiliated company” and the *Edgar-Allegheny* FERC principles.

A. Process Issues: Transparency and Independent Oversight; Disclosure of Affiliate Relationships

i. Transparency

According to the *Edgar-Allegheny* principles, transparency is the free flow of information to all prospective and actual bidders. No party, particularly the affiliate should have an informational advantage in any part of the solicitation process. Transparency also means that the RFP and all relevant information should be released to all potential bidders at the same time. All aspects of the competitive solicitation should be widely publicized. The issuer can post the RFP on its website and issue a press release to that effect and/or advertise in the trade press. Also, to compete effectively, all bidders should have equal access to data relevant to the RFP and such information should be made available to all bidders at the same time. Transparency is also an objective from the standpoint of the public.

The Distribution Companies and DOER took a variety of steps to comply with the transparency principle. The Evaluation Team created and maintained a publicly available website (<https://macleanenergy.com>) which contained all relevant documents for prospective bidders, which were made available to them at the same time. The website contained the following types of information relevant to 83D:

- 83D documents
 - RFP and bidder response forms
 - Model PPAs for different types of generation bids and list of requirements applicable to transmission proposals
 - Form of notice of intent to bid
 - Standards of Conduct
 - EDC Evaluation Team members
 - Department order approving RFP for issuance
 - Stakeholder comments to EDCs prior to Distribution Company filing draft RFP for approval
- RFP timeline
- Bidder conference presentation
- Evaluation Team responses to prospective bidder questions
- Public versions of submitted bids



- Various posts regarding the selection of NPT, the decision to conditionally select NECEC after NH SEC's denial of NPT's application for site approval, and the termination of the conditional selection of NPT

The Distribution Companies and DOER acted to make the RFP known to a wide group of stakeholders. Before submitting the draft RFP to the Department for approval, the Distribution Companies sought comments from over 600 stakeholders on certain questions important to the design of the RFP and evaluation of bids, <https://macleanenergy.com/2016/12/19/83d-stakeholder-comments-requested/>, and posted the responses of over 30 commenters.⁷¹ The RFP was then vetted with the Department, which allowed for participation by interested parties. Following the Department's approval of the RFP for issuance, the Distribution Companies notified an extensive list of prospective bidders and interested parties regarding the launch of the RFP, as they had in past solicitations.⁷² Finally, the reports issued by the Independent Evaluator, including the report previously submitted on RFP design and this report regarding the bid evaluation and selection process, facilitate the transparency of the process.

In addition, the Distribution Companies which expected to receive affiliate bids—National Grid and Eversource—developed Standards of Conduct designed to ensure that affiliates have no competitive advantage for gaining access to information that is not available to third-party bidders. Under the pertinent Standard of Conduct, National Grid and Eversource designated the individuals participating in the Solicitation process, and identified the role of each individual in the process. Utility individuals were allowed to be on either a Bid Team or an Evaluation Team within their respective companies (Unitil only had an Evaluation Team). No individual was allowed to be a member of both teams, and no individual was permitted to change from one team to the other during the solicitation process. However, some individuals who are neither members of the Bid Team or Evaluation Team but who provide guidance or advice to the Bid Team and/or Evaluation Team in the normal course of their responsibilities could be designated as Subject Matter Experts ("SMEs") and could communicate with members of both teams, although they could not be conduits for confidential information pertaining to the RFP. The Distribution Companies published the names of the individuals designated to be on the Evaluation Team and those designated as SMEs on the solicitation website. All team members were required to sign an agreement acknowledging that they would be bound by the Standard of Conduct and will be subject to training on the Standard of Conduct.

The IE had the opportunity to review and comment on the proposed Standards of Conduct. The IE expressed that it would be preferable that joint use of SMEs not be used in order to reduce the risk of transfer of confidential information between Bid Team and Evaluation Team and to enhance the

⁷¹ <https://macleanenergy.com/83d/83d-archived-documents-and-stakeholder-comments/>. The distribution list is derived from prospective bidders and other interested parties who signed up to receive notifications regarding the multi-state Clean Energy RFP and its associated website, <https://cleanenergyrfp.com>.

⁷² The Distribution Companies used the same distribution list as it used to solicit comments, as updated.

appearance of fairness and impartiality.⁷³ However, the IE stated that joint use of SMEs would be acceptable, with several modifications, including posting of the names of SMEs on the solicitation website and limiting the use of SMEs, which the Distribution Companies agreed to implement.⁷⁴ The Department approved this approach.⁷⁵

At the end of the process, after the contracts with HQUS and CMP had been executed, the IE asked National Grid and Eversource to state in writing whether they had complied with the standards of conduct. They responded affirmatively.

During the pendency of the RFP, the Evaluation Team did not provide the detailed evaluation framework or a summary of it to prospective bidders or the public. This is a common practice in the implementation of complex solicitations, such as 83D, and has been the Distribution Companies' practice in past solicitations. The rationale behind the practice is to encourage prospective bidders to put their best proposal forward rather than to facilitate their "gaming" of the evaluation system. In addition, putting together and making public a summary of the detailed evaluation framework prior to the submission of bids would have put an additional burden on the Evaluation Team, which was already struggling with timely meeting milestones for the solicitation process. Compliance with the transparency principle is typically assessed in the context of other procurement objectives and exigencies. In the IE's view, the principles of the evaluation framework set forth in the RFP, the bidder response package in the RFP, and the responses and public posting of over 100 bidder questions provided sufficient guidance for bidders to be able to submit competitive bids and for bidders to have a sufficient level of understanding as to basis upon which their bids would be evaluated.

Overall, the Distribution Companies and DOER implemented the RFP process in a manner that was open and that satisfies the transparency principle, in the IE's opinion.

2. Independent Oversight

The *Edgar-Allegheny* oversight principle provides that effective oversight of competitive solicitations can be accomplished by using an independent third-party with respect to the design and implementation of the competitive solicitation process. Ensuring that the third-party is independent and granting it at the outset oversight responsibility will help to ensure that the process will be conducted fairly throughout the process and will also minimize perceptions of affiliate abuse. 83D requires the appointment of an independent evaluator—selected jointly by DOER and the AGO—to monitor and report on the solicitation process and to provide its independent assessment of whether all bids were evaluated in a fair and non-discriminatory basis.

⁷³ IE RFP Design Report at 9-11.

⁷⁴ *Id.*

⁷⁵ D.P.U. 17-32 at 53-55.

Structurally, the 83D solicitation process contains numerous provisions for the independent oversight of the process. During the 83D RFP design phase, the process was subject not only to the independent oversight by the IE but also involved participation by DOER and the AGO. Importantly, the proposed RFP was the product of an agreement between three different Distribution Companies and DOER, and was subject to the Department's review and approval, after allowing comments by interested parties. Thereafter, DOER was a member of the Evaluation Team with the Distribution Companies and was intimately involved in developing the detailed evaluation framework, evaluating bids, and bid selection, with the IE actively involved in oversight of the entire process. DOER and the IE both had the opportunity to monitor contract negotiations between the Distribution Companies and selected bidders.

Solicitation processes have different strengths and weaknesses with respect to the oversight principle (as well as other considerations). While the degree of independent oversight was very strong, as outlined above, the process also had a few weaknesses. The IE was not brought into the deliberations regarding the RFP design until several weeks after they commenced. However, the IE had the opportunity to review drafts of the RFP and issues lists and participate in discussions with the Distribution Companies, DOER and the AGO on RFP design issues, so the impact was *de minimis*.

Another weakness was the limitations on IE (and DOER) access to draft contracts and substantive emails between the EDCs and the winning bidders during contract negotiations. The IE was only allowed physical access to these documents without the ability to retain them. Typically, the industry practice is that the IE is copied on all communications between bidders and the utilities, including throughout contract negotiations. However, the IE was able to monitor the contract negotiations throughout, provide comments to the EDCs during intra-EDC conference calls, and review the draft documents in person on request.

On the whole, there was strong independent oversight over the entire process.

3. Disclosure of Affiliate Relationships

The Independent Evaluator provided input into provisions of the RFP, the form of bidder certification, and the bidder response package to require bidders to identify any affiliate relationship with a Distribution Company or any financial interest that a Distribution Company had with the bidder or the proposed project.⁷⁶ The purpose of this was to ensure that there are no proposals where a Distribution Company has an undisclosed affiliate or financial interest in a bidder or proposed project. The IE had, as a team member, a forensic accountant, who provided assistance on these matters.⁷⁷ The accounting firm, Meaden & Moore, concluded that the utility affiliates who submitted bids, Northern Pass, Granite

⁷⁶ RFP sections 1.8, 2.2.1.5, and parts of Appendix B, Section 5.

⁷⁷ The use of a forensic accountant for this purpose was required, or at least encouraged, in the DOER RFQ for independent evaluator services.

State Powerlink, and Northeast Renewable Power Partners, properly disclosed their affiliate relationships, and that there were no bidders that failed to properly disclose any affiliated relationships.

B. Fairness of the Bid Evaluation Framework

An important part of the RFP process is the evaluation framework that is described in the RFP and the detailed evaluation framework that is developed to implement the provisions of the RFP. Under the *Edgar-Allegheny* principles, there are two guidelines that are of particular applicability to this part of the solicitation process—product definition and evaluation.

In *Allegheny*, FERC stated with respect to the “product definition” guideline:

The product or products sought through the RFP should be defined in a manner that is clear and nondiscriminatory. The RFP should state all relevant aspects of the product or products sought.

An RFP should not be written to exclude products that can appropriately fill the issuing company’s objectives. This is particularly important if such exclusions tend to favor affiliates.⁷⁸

Another of the four *Allegheny* criteria is:

Evaluation: evaluation criteria should be standardized and applied equally. . . .

To fulfill the evaluation principle, RFPs should clearly specify the price and nonprice criteria under which the bids are evaluated.⁷⁹

In this section of the report, the evaluation framework set forth in the RFP and the detailed evaluation framework developed after the RFP was issued will be analyzed in terms of (a) fairness and non-discrimination toward any types of bids and non-favoritism toward affiliates and (b) whether the detailed evaluation framework fairly implemented the more general provisions of the RFP. For purposes of this section of the report, the detailed evaluation framework includes the evaluation protocols developed after the RFP was issued, written answers to bidder questions, and the base case developed in connection with the evaluation of bids.

1. Interconnection Requirements

There are three principal requirements in the RFP pertaining to interconnection and delivery.

- Bidders are required to interconnect to the ISO-NE grid based on the CCIS (as well as the minimum interconnection standard);

⁷⁸ 108 FERC ¶ 61,082 (2004) at 8.

⁷⁹ 108 FERC ¶ 61,082 (2004) at 7, 8.



- Bidders must demonstrate that their proposed delivery into the ISO-NE grid, along with proposed transmission network upgrades, is sufficient to ensure “full dispatch” of the proposed clean energy deliveries; and
- Bidders that do not have certain interconnection studies completed by ISO-NE are required to submit technical reports or system impact studies under the current serial study process, even though ISO-NE was at the time in the process of converting to a cluster study process, subject to FERC approval, which affected certain projects in Maine.

In our RFP Design Report, the IE concurred with the use of the CCIS standard in the 83D solicitation (pp. 13-15), recognizing that this higher standard of interconnection than the “energy only” standard for Network Interconnection Service required in prior solicitations under Section 83 and 83A was justified in the context of 83D’s greater emphasis on reliability, noting the 83D statutory criteria that clean energy generation “contribute to reducing winter electricity price spikes” and “guarantee energy delivery in winter months.”

However, the IE was uncomfortable with the requirement that bidders demonstrate that proposed delivery, along with transmission network upgrades, is sufficient to ensure “full dispatch” of proposed energy deliveries. There is no ISO-NE study or requirement that is based on that standard. In fact, the “full dispatch” standard is substantially stricter than the CCIS standard, and ISO studies do not review for “full dispatch.” Moreover, how to “ensure” full dispatch is unclear, which is undesirable for a RFP threshold requirement. Finally, the issue of transmission constraints and impacts on delivered energy prices and project curtailment can, and was planned to be, evaluated in the quantitative nodal energy market simulation modeling.

The Evaluation Team addressed this issue, with the input of the IE, in response to a bidder question, with the answer posted to the RFP website. After explaining that a bidder would need to provide an ISO study based on the CCIS standard or a technical study provided by the bidder that would approximate an ISO study, the Evaluation Team explained:

The delivery profile submitted by the bidder should reflect any remaining projected constraints or curtailments, if any, associated with the proposal (after inclusion of any network upgrades associated with application of the CCIS-equivalent interconnection standard). If a bidder desires to reduce further any constraints or curtailments associated with its proposals, it must identify additional network upgrades (which would be instituted through an elective process with ISO-NE), estimated costs to achieve this result, proposed cost containment measures, and the delivery profile associated with the proposed level of network upgrades, all with supporting studies and information.⁸⁰

⁸⁰ Answer to Question 16, 83D Q&A Set 8. <https://macleanenergy.files.wordpress.com/2017/03/83d-ga-set-8.pdf>.



In practice, the Evaluation Team interpreted “full dispatch” as an obligation to incorporate any expected curtailments in the delivery profile submitted by the bidder, plus a bidder option, rather than a requirement, to identify additional upgrades to achieve “full dispatch.” The IE found this approach to be reasonable.

Following the issuance of the RFP, ISO-NE proposed to FERC modifications to its interconnection process to provide for a cluster study process for certain projects interconnecting in Maine, which FERC approved on October 31, 2017 and made effective on November 1, 2017.⁸¹ The Evaluation Team applied the interconnection requirements applicable to cluster-eligible projects under FERC’s revised rules (to the extent different from pre-existing requirements), both from a threshold requirements standpoint and in its qualitative evaluation of bids. The IE concurred with this approach, which relied on currently effective rules.

There were a number of bidders that sought clarification regarding the standards the Evaluation Team would apply based on the applicable RFP provisions. The Evaluation Team provided clarification in written responses, after seeking input from ISO-NE, with the answers being reviewed and concurred in by the IE.⁸² On the whole, the IE was satisfied that the interconnection requirements in the RFP as further interpreted in answers provided to bidders were designed and articulated in a fair, clearly stated, transparent and non-discriminatory manner.

2. Detailed Evaluation Framework

The Evaluation Team devoted considerable time and effort to develop a detailed quantitative evaluation framework pursuant to the more general provisions set forth in the RFP. The model used by TCR—ENELYTIX—allowed for more sophisticated quantitative evaluation than in prior solicitations. Also, this was the first Massachusetts RFP process where GWSA compliance value was part of the evaluation process. Finally, the evaluation process evolved following enactment of the CES and Evaluation Team review of initial quantitative results, with the concurrence of the IE.

The evaluation framework properly considered the projected market value of energy purchased under the proposed contracts. This was based on running ENELYTIX with the proposed project in service and determining the value of energy at the proposed delivery point. This is the point at which the EDCs would purchase the proposed energy (and, in all likelihood, sell the energy back into the market at the same point).

The environmental attributes and the market products embodying them were incorporated in the evaluation in three ways:

⁸¹ ISO New England Inc., 161 FERC ¶ 61,123 (2017).

⁸² See answers to questions 15, 16, 31, 36, 72, 82, 117, 118, and 119, 83D Q&A Set 8. <https://macleanenergy.files.wordpress.com/2017/03/83d-ga-set-8.pdf>

- The direct benefits associated with RECs and CECs
- The indirect benefits associated with the reduction of REC and CEC prices that EDCs and other retail electric suppliers would need to pay for these products other than those that the EDCs are or will be procuring under long-term contracts
- The value associated with reduction of emissions pursuant to the GWSA

At the time the RFP was issued, the Clean Energy Standard was a proposed rule (issued as a proposal in December 2016). The rules were finalized in August 2017 and then amended in December 2017. The evaluation performed incorporated the rules as they were finalized and amended. One major impact of the CES rules was that it greatly expanded the demand for clean energy—both RPS eligible generation and hydroelectric generation procured under 83D—and, hence, their value in the evaluation.⁸³

Important aspects of the evaluation included:

- Using the ENELYTIX model, REC and CEC values are based on the “missing money” required to meet RPS and CES requirements above market energy value (and applicable capacity value), subject to ACP values under the RPS and CES, which act as price caps
- CEC values in many years were based on the ACP, which, in most years, is 50% of the RPS ACP value⁸⁴
- Where RECs or CECs were projected to be retained by the EDCs, the value of the RECs or CECs in the evaluation was assumed to be their avoided cost; where they were assumed to be sold (because the amount purchased was in excess of the EDCs assumed basic service obligations), the value was based on the projected sale price.⁸⁵
- The value of the RECs/CECs purchased were treated as a direct benefit of the project proposal.

⁸³ The CES requires Massachusetts retail suppliers (excepting municipal utilities) to obtain Clean Generation Attributes (including those from RPS Class I generating units) in amounts equal to 16 percent of their sales in 2018, increasing by 2 percent per year until 80 percent in 2050. 310 CMR 7.75(4). In contrast, the percentage requirement applicable to RPS Class I (subject to the solar carve outs) is 13 percent in 2018 and increases by 1 percent per year thereafter. 225 CMR 14.07.

⁸⁴ With respect to the RPS, it was assumed that merchant RPS qualifying generation would meet RPS demand beyond existing RPS qualifying generation, assumed imports, and projected offshore wind projects to be procured under 83C. The ENELYTIX model did not specifically “solve” for CES compliance, thus, did not assume that merchant generation would be built to meet CES demand (unless such CES-qualifying generation would be built for economic reasons). The IE was satisfied that these assumptions were reasonable in light of the relatively small amount of new large clean generation that has been built in the region in the absence of long-term contracts.

⁸⁵ Under 83D(h), “a distribution company shall retain renewable energy certificates that are not attributed to Class I renewable portfolio standard eligible resources.” Under the CES rules, as amended, all generation attributes retained under this statutory provision are clean generation attributes qualifying under the CES. 310 CMR 7.75(2) (definition of “Clean Generation Attribute”), which are clean generation attributes from hydro facilities procured under 83D. Under the amended rule, these retained CECs “shall be assigned to all end use customers served by all retail sellers subject to 310 CMR 7.75(4) [which exclude municipal electric departments and municipal light boards]”.



- The impact on future REC and CEC prices as a result of the proposed increment of RECs and CECs being created as a result of the proposed projects and the resulting impacts on the cost of RECs and CECs required to be purchased to serve Massachusetts retail load—an indirect benefit;
- The economic value on a \$/MWh basis associated with GHG emissions reductions attributed to Massachusetts under the GWSA based on the manner in which Massachusetts accounts for GHG emissions attributable to Massachusetts under the GWSA—using the GHG inventory accounting methodology, another indirect benefit.

The IE views the evaluation framework regarding environmental attributes, described in more detail at Section III.B.3.b. of this report, as being fair, non-discriminatory and reasonably based on the applicable statutory and regulatory provisions and practices under the RPS, CES, and GWSA. The IE appreciates that strong arguments can be made for the different approaches regarding whether the REC and CEC market values should be considered as being part of the GWSA compliance value—the position taken by DOER with the support of Eversource and Unitil—or whether it should be considered as separate and distinct and therefore additive—the position taken by National Grid. As previously indicated in this report, the IE supports the approach taken by DOER, with the support of the majority of the Evaluation Team, primarily because deference should be given, in the IE’s opinion, to the agency and its sister agency, DEP, who are charged with implementing the pertinent statutes and regulations and which are responsible for energy and environmental policy.⁸⁶ As it turned out, the different approaches regarding environmental attribute valuation did not appear to make a major difference in the evaluation results when different projects/portfolios were compared against each other. NECEC Hydro was the top-ranked portfolio based on the real levelized \$/MWh evaluation metric under both approaches.

Another indirect benefit was the impact of the project proposals on projected energy prices for Massachusetts EDC customers, which was an output from the ENELYTIX modeling. For most of the project proposals, this was a benefit, as injecting low marginal cost energy into the grid would reasonably be expected to reduce LMPs throughout New England, in the absence of material transmission constraints. Based on the initial evaluation results for small projects, it appeared that the outputs reflected modeling “noise” more than reasonable energy price changes, especially because the LMP price increases or decreases were divided by a small number of project MWhs to produce a \$/MWh value. It was reasonable, in the IE’s opinion, not to include the energy price change value (as well as other indirect benefits) in the evaluation of individual small projects, but to include it in both the Stage 2

⁸⁶ While Evaluation Team members may certainly assert their right to express their opinions regarding evaluation framework matters, it is difficult to manage a decision making process operating on a consensus basis where dissenting parties are unwilling to accede to the majority. At least, there was only one instance of this occurring. The IE does not know whether this was due only to a strongly held opinion of National Grid or whether it was influenced by the likelihood that National Grid’s preferred approach would be more favorable to National Grid’s affiliate wind and wind/hydro bids than the approach preferred by other members of the Evaluation Team (one of which, it should be noted, had an affiliate hydro and hydro/wind bid).

evaluation for large projects and the Stage 3 portfolio evaluation, which included aggregations of small projects in a number of the portfolios created for Stage 3.

The IE was also comfortable with the “hedge value” that TCR created to measure the extent to which a proposal/portfolio would mitigate price increases in the winter months due to unusually high natural gas prices in the winter months. In the IE’s opinion, this was a reasonable way to address the “economic impacts associated with resource firmness,” a criterion set forth in Section 2.3.1.2 of the RFP and 83D’s criterion of “contribut[ing] to reducing winter electricity price spikes.”⁸⁷ The particular formulation was the result of a collaboration with the Evaluation Team and TCR after consideration of several alternative approaches.

Other potential quantitative evaluation measures were considered but were not included for reasons that the IE found to be sound—such as the future impact on the needs for additional ancillary services and associated costs associated with intermittent generation, because of the lack of appropriate data. Another instance was the decision not to use outputs of the ENELYTIX model regarding the impact on capacity prices, because the model results did not appear to be reliable and consistent and that recent changes to ISO-NE’s Competitive Auctions with Sponsored Resources (“CASPR”) proposal made it less likely that new state-sponsored resources would impact capacity market prices.⁸⁸ These factors, however, were generally considered in the qualitative evaluation under the “Reliability” category.⁸⁹

The IE found the detailed qualitative evaluation framework—which addressed indicia of project viability, benefits not quantified in the quantitative evaluation, and cost and contractual risks not considered in the quantitative evaluation—to be reasonably based on the provisions of the RFP, fair to different types of allowable bids, and consistent with the statutory intent of 83D. The Stage 3 evaluation protocol followed the RFP provisions applicable to Stage 3.

The resulting evaluation framework was standardized for application to all proposals and portfolios of proposals and, in the IE’s opinion, was fair and non-discriminatory toward all proposals and not unduly influenced by the fact that there were several bidders who were affiliates of two of the EDCs.

In addition, the products being solicited—energy and RECs for RPS Class 1 resources and energy and environmental attributes for hydro resources—along with variants involving combinations of the foregoing products and for proposals involving proposed transmission projects were, in the IE’s opinion, stated with sufficient clarity. This was improved through the question and answer process, pursuant to

⁸⁷ 83D(d)(5)(ii).

⁸⁸ FERC approved the CASPR proposal in March 2018. *ISO New England Inc.*, 162 FERC ¶ 61,205 (2018).

⁸⁹ Included for consideration in this category was the extent to which the proposed project MWhs were firm or firming, the percent of project MWhs proposed for delivery during winter and summer peak hours, the reduction in natural gas burn during winter months relative to project MWhs, whether the proposed project is being paired with energy storage, and whether a proposed project is being delivered to eastern Massachusetts, rest-of-system in ISO-NE that is neither import nor export constrained, or in an export-constrained zone.

which the Evaluation Team provided written answers to more than 100 questions posed by prospective bidders, which were posted on the RFP website.

There were, however, several weaknesses in the evaluation framework. One weakness was the lack of a form Transmission Service Agreement for transmission bidders, which would have focused bidders on desired terms and conditions and facilitated Evaluation Team review of the bids. However, this was not at all a fatal weakness, and was favored by the EDCs due to their lack of experience with these types of agreements in a competitive bidding context (in contrast to PPAs) and the desire to facilitate creative proposals.

Another weakness, in the IE's opinion, was a difference in the change in law requirements for RPS Class I project bidders and firm hydro bidders. For RPS Class I projects, if there was a change in law such that the RECs ceased to conform with RPS Class I eligibility criteria, the EDCs could purchase only the energy under the PPA at the price specified for energy and not pay for the RECs. For firm hydro bidders, there was no similar requirement if the generation attributes no longer complied with the CES due to a change in law. In the RFP design report, the IE recommended deletion of the change in law requirement applicable to RPS Class I projects "if RPS Class I RECs and the associated environmental attributes are being evaluated in a manner that is comparable to that of the hydro environmental attributes."⁹⁰

While a weakness in terms of treating different types of generating resources fairly, the IE does not find this to be a major weakness in the context of the solicitation overall. First, the Department rejected the recommendation of the IE and several stakeholders to eliminate the RFP's RPS change in law requirement.⁹¹ Hence, it was appropriate for the Distribution Companies to implement the RFP with that requirement. Second, the CES was made final after the submittal of bids, and the RFP and the form agreements for firm hydro bids were not structured with a change in law provision regarding the CES which was then not in effect. It would not have been fair to apply to firm hydro (or firming hydro) bids a requirement that they take CES change in law risk after they had submitted their bids. Moreover, these bidders had not been required to bid separate pricing for energy and CES-compliant attributes in a similar way that RPS Class I qualifying bids were required to provide separate pricing for energy and RECs so the firm hydro bids did not provide a mechanism by which CES change in law risk could be limited to a specified \$/MWh amount.

For the foregoing reasons, it is the IE's opinion that the evaluation framework overall was standardized, fair, non-discriminatory, and non-preferential.

⁹⁰ RFP Design Report at 22.

⁹¹ Fitchburg Gas and Electric Company et al., D.P.U. 17-32 at 47-52.

C. Fairness of the Bid Evaluation and Selection Process

1. Threshold Evaluation

As indicated in Section III.C.1 of the report, 17 of the 53 project proposals were determined not to meet eligibility and threshold requirements. This is an unusually large percentage of projects that were disqualified for failure to meet minimum requirements for a competitive solicitation of this type. The primary reasons were the unusually strict minimum standards set forth in the RFP—particularly with respect to the interconnection and delivery requirements, which was the cause for the majority of disqualifications. Other reasons for failure to meet minimum RFP standards were failure to demonstrate site control, failure to provide financial information/demonstrate financial viability, and ineligibility based on existing hydro facilities in ISO-New England not providing incremental hydro.

The Evaluation Team considered many bids that different members of the Evaluation Team claimed did not meet one threshold requirement or another. In some cases, there were different interpretations of what was or was not a threshold requirement or how it should be applied in the context of a particular proposal. The IE took the position that threshold requirements should be narrowly construed and that only bids that clearly failed to pass threshold/eligibility requirements after bidders were given an opportunity to cure any deficiencies (or even where the deficiency was not reasonably curable, to explain their situation relative to the RFP requirement). The IE was satisfied that the Evaluation Team's decisions to disqualify bids was justified based on the application of RFP requirements to the particular proposal.

There were several other bids that the Evaluation Team considered as to whether they should be disqualified, but for which there was not unanimity in support of disqualification. None of these bids were competitive in the Stage 2 and Stage 3 evaluations, so that any failure to disqualify these bids was not material to the result of the solicitation.

2. Stage 2 and Stage 3 Evaluation and Bid Selection

Key to evaluation and bid selection is whether the evaluation framework was properly followed and applied in the evaluation of specific proposals and done so on a non-preferential and non-discriminatory basis. This applies for the quantitative analysis, the qualitative evaluation, the Stage 3 evaluation process and bid selection.

The IE saw some issues with the evaluation and selection process. 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, including [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.

However, the evaluation process conducted by the Evaluation Team, with the oversight of the IE, counteracted any favoritism on the part of Eversource, such that the IE was comfortable that the resulting Stage 2 and Stage 3 evaluations were fairly conducted and not unduly preferential toward any bid nor unjustly discriminatory toward any bid. As mentioned previously, some of the issues, such as the interest rate to be used in the quantitative evaluation for NPT, was not properly addressed until toward the end of the evaluation process. In the IE's opinion, a reasonable forecasted interest rate, rather than the bidder-supplied very low interest rate, based on then-current interest rate levels, should have been used in the Stage 2 evaluation. However, a reasonable forecasted interest rate was finally applied in the Stage 3 evaluation, and DOER's ultimate decision was based on the quantitative evaluation using the forecasted 4.45% interest rate recommended by TCR, the Evaluation Consultant, with the support of the IE and National Grid.

Ultimately, the decision regarding which proposal to select was made by DOER because the EDCs did not agree on the selection decision. DOER followed the directives of 83D and consulted with the IE prior to making a decision. Generally, DOER's decision to select Northern Pass (it's initial decision) was within the guidelines that the IE provided for decision making:

- The decision was among the two proposals that the EDCs had recommended for selection and which were the two top-ranked bids (other than mutually exclusive bid variants of which NECEC was the major component);
- DOER used the 4.45% interest rate forecast for NPT in its decision making, rather than the bidder-supplied [REDACTED] % estimate;
- DOER viewed the net present value benefits for NPT as being comparable to those for NECEC (they were within [REDACTED] percent).

DOER concluded that NPT deserved selection for a number of reasons (as set forth in the memo explaining DOER's determination):

- NPT had an earlier proposed on-line date and was more advanced in permitting and interconnection processes, supporting a stronger likelihood of an earlier on-line date
- By coming online earlier, NPT would provide additional and earlier GHG reductions assisting the Commonwealth in meeting GWSA requirements and providing earlier insurance benefits against winter price spikes

In the IE's opinion, DOER's decisional memo should have given more weight or at least referenced the quantitative evaluations of the proposals using the metric of real levelized \$/ MWh net benefits chosen

by the Evaluation Team and the scoring and ranking of the bids using that metric.⁹² However, the IE was and is satisfied that DOER considered that the NECEC proposal was evaluated as having more net benefits in the quantitative evaluation. Moreover, the factors DOER cited in support of its decision were those that were proper for it to consider as the basis for its selection decision. Overall, it was the IE's opinion, that DOER's selection of NPT was one that was fairly made and within DOER's authority under the RFP and within the guidelines for decision set forth in the RFP and the Stage 3 evaluation protocol.

Following the decision by the NHSEC to deny NPT's siting authority permit a week later, DOER initiated a process that ultimately led to the conditional selection of NECEC, the termination of the conditional selection of NPT, and the negotiations leading up to the execution of agreements with HQUS and CMP. There was consensus among the EDCs that the NECEC bid was the best proposal to be the "back up" bid to NPT after NPT's site authority permit was denied. Again, it was DOER that ultimately decided to terminate NPT's conditional selection. The IE believed that the decision made by DOER was appropriate in the particular context, given the unanimous NHSEC permit denial and no indication that it would be reversed in time for NPT to start construction by [REDACTED], as proposed.⁹³ It also allowed the EDCs to focus negotiations on NECEC and the accompanying HQUS PPA, which facilitated the conduct and completion of the contract negotiations.

In the IE's opinion, the decision to select NECEC (first, as an alternative to NPT and, then, as the project for which contract negotiations would be conducted exclusively) was amply warranted. The NECEC 100% hydro proposal was the top-ranked proposal and was highest ranking in the quantitative evaluation. It also had the highest benefits based on NPV total \$, an alternative economic metric. While NECEC was at an early stage in the interconnection process, which was subject to the Maine cluster study process, and at a relative early stage in the permitting process as well, it, at least, had not received a unanimous denial of a required permit.⁹⁴ The next mutually exclusive bid in rank order was [REDACTED], which already had achieved many major project development milestones but had higher costs and lower net

⁹² DOER's ranking of bids using both the real levelized \$/MWh metric and the NPV \$ alternative metric prior to selection and the IE's consultations with DOER prior to and after its selection decision indicate that DOER considered and did give some weight to the bid evaluations using the real levelized \$/MWh metric.

⁹³ Of note, Section 83D(d)(5)(vii) provides that a proposal must "adequately demonstrate project viability in a commercially reasonable timeframe." It is the IE's view that DOER's decision to terminate negotiations with a project whose key siting authority application had been unanimously denied by the siting authority was consistent with the statutory intent of 83D.

⁹⁴ [REDACTED]



benefits and a lower total score and ranking. The decision to select NECEC over [REDACTED] was fairly and reasonably made.

D. Contract Negotiation Process

As indicated previously, the IE monitored the contract negotiations, subject to limitations. However, the IE was able to discuss with the EDCs outside of the negotiations the scope and focus of the IE review and any matters that were of concern to the IE. Finally, the IE was able to review the contract drafts when negotiations were at an advanced stage and the final execution copies of the agreements.

There were several issues that were presented during the contract negotiation from the IE's perspective.

First, National Grid wanted to obtain a contractual commitment from HRE that it would deliver from HQ hydro resources a substantial amount of energy over the term of the 20-year HRE contract outside of the contract such that the deliveries under the 20-year HRE contract would be considered "Incremental Hydroelectric Generation" within the meaning of the RFP. Under the RFP, "Incremental Hydroelectric Generation" is defined 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.⁹⁵

In Section 4.1 of the Bidder Response Form (Appendix B to the RFP), hydropower bidders were required to provide the following information:

Describe why the generation proposal qualifies as Incremental Hydropower Generation. If the entire project is not new, specify the amount of power provided to or sold into the ISO-NE market during 2014, 2015, and 2016. Provide information which demonstrates that the resources and transmission capacity described in your proposal are capable of providing an increase in the amount of such power compared to the average power deliveries in ISO-NE over those three years.

The form PPA did not contain any specific provision requiring that a seller of existing hydropower generation deliver any amount of energy other than that being committed to under the proposed contract. Neither the IE, the other EDCs nor DOER agreed with National Grid that the RFP or form PPA required the type of commitment that National Grid was seeking [REDACTED]. Imposing a major obligation or liability on a bidder that was not contemplated by the form PPA and was not included within the scope of a bidder's proposal raised a fairness question. However, the IE noted that this

⁹⁵ 83D RFP, p. B.



matter had been raised by a number of parties, including HQUS, during the RFP approval process before the Department. HQUS, concerned that it could be required to deliver the historical amount of generation into New England outside of the contract, sought a modification to the definition of “Incremental Hydroelectric Generation” to simply refer to generation that is *capable* of delivering a net increase in hydropower deliveries into New England. This proposed modification was opposed by several commenters. The Department stated:

The Department agrees that there would be a risk to ratepayers if an electric distribution company entered into a contract with a bidder based on a bidder’s capability to provide a net increase in MWh/year of hydroelectric generation. If the bidder subsequently failed to provide a net increase in generation, ratepayers would have paid for a service (i.e., Incremental Hydroelectric Generation) that the bidder did not deliver.⁹⁶

On the other side of the argument, a commenter argued that the RFP definition be modified so that the proposed deliveries must be in addition to historical deliveries without any exceptions. The Department rejected this proposed modification as well.⁹⁷

The IE noted that while there was a fairness issue because a contractual requirement for deliveries outside of the proposed contract was not clearly stated either in the RFP or form PPA, the IE also noted that whether proposed imports would in fact be incremental to other deliveries HQUS would make was a matter of concern to the Department. The IE recommended that the Department’s decision with respect to this matter be raised with HQUS in the negotiations. Under the totality of the circumstances, the IE advised that it was acceptable for National Grid to negotiate to obtain a contractual commitment from HQUS on this matter, but cautioned that it be pursued in a manner that would not cause a collapse of the negotiations.

Another key issue in the negotiations involved the termination payments for which HQUS would be responsible for in the event that CMP defaulted on its obligations under the TSA (non-excused transmission outages) resulting in a contract termination by the EDCs. [REDACTED]

[REDACTED]
[REDACTED]
[REDACTED]

[REDACTED] The IE advised that it was appropriate for the EDCs to seek to negotiate full cover damages in this circumstance, but it was not a requirement of the RFP.

The RFP clearly states that for firm hydro proposals, the seller will be responsible for liquidated damages for failure to deliver (RFP section 2.2.1.3.i) and where transmission is part of a packaged bid, the bidder will be responsible for both liquidated damages for the energy and liquidated damages for associated

⁹⁶ D.P.U. 17-32, at 33.

⁹⁷ *Id.* at 31-33.

transmission support costs (RFP section 2.2.1.3.iv). However, “liquidated damages” is not further defined in the RFP (although “cover damages” was defined in the form PPA as the remedy for seller unexcused failure to deliver). When several commenters had asked the Department to modify the RFP to more clearly define “liquidated damages,” the Department declined to do so and stated that “we expect parties to address the particulars of any liquidated damages provisions during the course of contract negotiations.”⁹⁸

[REDACTED]

[REDACTED] Overall, however, each of the three EDCs were able to negotiate risk allocation provisions, including seller damage provisions, that were significantly better from an EDC/EDC customer standpoint than those included in the NECEC/HRE bids.⁹⁹

Another issue was how to address what HQUS’ contractual obligations should be with respect to the CES, which was not promulgated until after HRE’s bid was submitted. The parties agreed to seek an interpretive ruling from DEP to obtain confirmation that its proposed manner of complying with the CES was appropriate (or be notified of any other applicable requirements or guidelines), with the right of either party to terminate if the interpretive ruling was unsatisfactory to it. Absent a termination, HQUS would be obligated to comply with the CES, and it would be obligated to use commercially reasonable efforts to comply with the CES if there was a change in law. This result seemed fair under the circumstances that the CES rules were not in effect at the time of bid submittal and the form PPA did not address CES rule compliance.

Finally, toward the end of the negotiations, [REDACTED]

⁹⁸ *Id.* at 45.

⁹⁹ In its RFP design report (p.25), the IE expressed concerns that the RFP allowed bidders to seek to recover abandoned plant costs at FERC if they failed to obtain required permits. In its bid, NECEC [REDACTED]. In the contract as executed, abandoned plant cost recovery is allowed only where abandonment of the project is caused by a change in Massachusetts law, with a cap on the EDCs’ potential liability, and only after non-appealable FERC and Department regulatory authorizations for the proposed project has been obtained.

¹⁰⁰ [REDACTED]



All in all, the IE found that the contracts that resulted from the negotiation process were no less adverse to the EDCs than the proposals and associated contracts submitted by HRE and CMP and, in many cases, were more favorable to the EDCs and their customers. This satisfied the criterion that the resulting contracts were consistent with, or at least no less favorable, than the proposals that were evaluated by the Evaluation Team.¹⁰¹

Neither CMP nor HQUS are affiliates of any of the EDCs. Hence, there was no issue of any undue preference given to affiliates in the negotiations. Nor was any such undue preference provided to HQUS or CMP.

The IE also monitored the negotiations and reviewed the contracts with respect to whether the contracts or any provision thereof violated any threshold requirement of the RFP. Neither the HQUS PPA nor the CMP TSA violate any RFP threshold requirement, in the IE's opinion.

All in all, the EDCs fairly negotiated the terms of the HQUS PPA and CMP PPA consistent with the requirements of the RFP.

VI. Conclusions

In this report, Peregrine, the Independent Evaluator for the 83D solicitation, has summarized and analyzed the entire solicitation, bid evaluation, selection and contract negotiation process which resulted in the execution, and filing for Department approval, of a power purchase agreement between the EDCs and HQUS and an accompanying transmission service agreement between the EDCs and Central Maine Power Company. These agreements are the result of a competitive bidding process for approximately 9,450,000 of annual MWh of Clean Energy Generation resources, as defined in 83D and the RFP previously approved for issuance by the Department. The Independent Evaluator has been closely involved in the entire solicitation process and has had access to all information and data related to the competitive solicitation and bid selection process necessary for the IE to perform its monitoring, oversight, and reporting functions, as more fully described in this report. It is the IE's conclusion that, in the phraseology of 83D, that "all bids were evaluated in a fair and non-discriminatory manner" and that the New England Clean Energy Connect 100% hydro bid, with energy supplied solely from Hydro Quebec hydroelectric generation resources, was fairly selected as the winning bid (after a proposal from

¹⁰¹ As part of the NECEC proposal, CMP proposed to contribute funding of \$50 million in total over a 40-year period following commercial operation of the NECEC project to provide benefits to low-income Massachusetts electricity customers (\$700,000 in Years 1-20 and \$1.1 million per year thereafter) and to promote innovative investments in customer-facing energy technologies targeting low-income Massachusetts households, such as applied energy storage technology (\$300,000 in Years 1-20 and \$400,000 per year thereafter). To effectuate this commitment, CMP has entered into a Memorandum of Understanding with Action, Inc. and Action for Boston Community Development, Inc. (collectively, "The Low Income Energy Affordability Network" or "LEAN") ("CMP/LEAN MOU"). The CMP/LEAN MOU is consistent with CMP's representations in the NECEC bid, based on the IE's review.

Northern Pass had been conditionally selected but whose conditional selection was terminated due to a denial of siting approval for the proposed Northern Pass transmission line). The NECEC 100% hydro bid was the highest ranking bid in the final evaluation of project portfolios (with quantities that approximated the 9,450,000 annual MWh procurement target) as well as the proposal with the highest net benefits and lowest cost per MWh in real levelized \$2017.

DOER, with the concurrence of the EDCs, requested that Peregrine also monitor the contract negotiations between the EDCs and the selected bidders, and Peregrine performed this function and has reported on its monitoring in this report.¹⁰² It is Peregrine's assessment that overall the EDCs fairly negotiated the contracts that have been submitted for the Department's approval, that the negotiated terms are at least as favorable as those included in HQUS' and CMP's winning proposals (as they were modified in the bidding process) for the NECEC 100% hydro bid, and that the resulting contracts satisfy the requirements of the 83D RFP. Moreover, the IE notes that the EDCs were able to negotiate improvements in certain risk allocation features in the PPA and TSA from HQUS' and CMP's proposals, thereby improving on them from the standpoint of the EDCs and their distribution customers.

Finally, as described in this report,¹⁰³ the solicitation was implemented in a manner that appropriately addressed or rendered moot the concerns the IE had noted in its RFP Design Report regarding interconnection requirements, the application of change in law provisions, and abandonment cost recovery for transmission projects.

¹⁰² This monitoring started when negotiations were expected to be exclusively with Northern Pass, an Eversource affiliate, and HRE, but continued throughout the time that negotiations were with NECEC and HRE/HQUS, non-affiliates of the EDCs.

¹⁰³ See Section II.B at p. 6 (IE suggested modifications in RFP Design Report), Section III.C.2.a at p. 24 (abandonment cost liability), Section V.B.1 at pp.41-43 (interconnection-related requirements), Section V.B.2 at p. 47 (change in law), and Section V.D at p. 53, n. 99 (abandonment cost liability) .



Appendix A - Qualifications and relevant experience of the Peregrine independent evaluator team

The Independent Evaluator for the 83D RFP consists of Peregrine Energy Group, Inc. (“Peregrine”) as the contracting party to the Massachusetts Department of Energy Resources (“DOER”), with four subcontractors--New Energy Opportunities, Inc. (“NEO”), Merrimack Energy Group, Inc. (“Merrimack”), Power Consulting Services, LLC, and Meaden & Moore, LLP (Meaden & Moore). The key individuals for the project team are:

- Paul Gromer, CEO of Peregrine
- Barry Sheingold, President of NEO
- Wayne Oliver, President of Merrimack
- David Andrus, Principal of Power Consulting Services, LLC
- Patrick Kelleher, Partner, Investigative Accounting Group, Meaden & Moore

Overall, Paul Gromer is responsible for management of the Independent Evaluator team, with Barry Sheingold serving as project lead for the 83D solicitation, Wayne Oliver as co-lead, David Andrus as transmission consultant, and Patrick Kelleher advising on affiliate relationships.

Mr. Gromer, CEO of Peregrine, is an attorney and former Massachusetts Commissioner of Energy Resources. He has led Peregrine in providing consulting and related services in the renewable energy, energy efficiency, and competitive retail energy fields over the past 25 years.

Barry Sheingold and Wayne Oliver have collaborated as IEs or consultants on a more than a dozen clean and alternative energy solicitations for long-term contracts, including:

- Southern California Edison Renewable Portfolio Standard solicitations for long-term contracts—4 solicitations (2009, 2013, 2014, 2015);
- NV Energy Emission Reduction and Capacity Replacement Renewable Energy RFPs—3 solicitations (2014, 2015 and 2016);
- Southern California Edison Company Request for Offers for Combined Heat and Power—3 solicitations (2012, 2013, 2014);
- PacifiCorp Request for Proposals for Renewable Electric Resources (2008);
- Delmarva Power solicitation for long-term contracts (2006).

In addition, NEO and Merrimack Energy have advised Massachusetts state agencies relating to the development and implementation of competitive procurement processes for long-term contracts to facilitate financing of renewable energy projects.



- Massachusetts Utilities Long-Term Contracting Requirements for Renewable Resources under Section 83 of the Green Communities Act (2009-2010);
- Massachusetts Technology Collaborative RFP for Options Agreements on Renewable Energy Certificates (2003-05).

Over the past 18 years, Mr. Sheingold has served as IE or provided consulting assistance in the clean energy field, with a specialty in power procurement. Mr. Sheingold served as DOER's principal consultant with respect to DOER's role in the design and implementation of two prior RFPs for long-term renewable energy contracts under Section 83A of the Green Communities Act ("GCA") and was the project lead on a study prepared on behalf of DOER for the Massachusetts legislature on the long-term contracting solicitation processes under Section 83 of the GCA. He has advised the New York State Energy Research and Development Authority regarding various rounds of its long-term contracting program for renewable energy attributes and related procurement matters. Mr. Sheingold has also performed an independent evaluator function for renewable energy RFPs in Oklahoma and Hawaii. He has submitted testimony or other assessments on a variety of renewable energy projects and utility procurement-related matters in a number of states and provinces. Mr. Sheingold has a broad electric industry background. Prior to founding NEO, Mr. Sheingold served in a business or legal role for an electric utility company, a power marketer, a power plant developer, and the Federal Energy Regulatory Commission.

Wayne Oliver, President of Merrimack, has served as IE or similar role on over 100 competitive procurement assignments dating back to 1989. His experience in this role has included RFPs for renewable resources, conventional generation options, energy storage projects and demand response and demand-side management resources. Mr. Oliver has reviewed and evaluated thousands of power supply proposals covering all types of technologies, fuel types, and financing and contractual structures.

Dave Andrus is a Vermont-based transmission consultant with over 30 years' experience. Mr. Andrus previously led a national transmission planning and analysis practice that provided consulting services in the areas of asset valuation, condition assessment, due diligence and owners engineer reviews, renewable energy integration analyses, interconnection/delivery/congestion studies, and market rules evaluations.

Patrick Kelleher is a partner in Meaden & Moore's Investigative Accounting Group and is in the firm's Boston office. The Investigative Accounting Group provides insurance services, forensic accounting, fraud evaluations examination assessment, measurement of economic damage and litigation support services among other things. As part of its responsibilities, the Investigative Accounting Group conducts forensic affiliate investigations between different business organization entities.



Appendix B - Key provisions of the 83D RFP

RFP Characteristics/ RFP Section	Summary/Description
Eligible Bid Categories Section 2.2.1.3	<p>There are four eligible bid categories:</p> <ol style="list-style-type: none"> 3. Proposal to sell Incremental Hydroelectric Generation (including environmental attributes) on a firm basis pursuant to a PPA; 4. Proposal to sell new Class I RPS eligible resources (energy and RECs or RECs only) pursuant to a PPA; 5. Proposal to sell new Class I RPS eligible resources firmed by Incremental Hydro Generation on a firm basis pursuant to a PPA; 6. Any of the foregoing types of PPA proposals packaged with a proposed transmission project with payments to be made under a FERC tariff and service agreement.
Contract term Section 2.2.1.6	The contract term is prescribed by statute—15 to 20 years.
Minimum Contract Size Section 2.2.1.7	20 MW.



Capacity, Interconnection and Delivery Requirements Sections 2.2.1.8; 2.2.1.9	<p>The Distribution Companies will not purchase capacity under long-term contracts.</p> <p>However, a proposal must describe the amount of capacity, and the capacity commitment period, for which the bidder expects the generation unit(s) in their proposal to qualify under the Forward Capacity Auction Qualification Requirements under the ISO-NE market rules.</p> <p>Each project must include a commitment to interconnect to an ISO New England Pool Transmission Facility (“PTF”) at the Capacity Capability Interconnection Standard. Bidders must demonstrate that the proposed point of delivery into ISO-NE, along with the proposed interconnection and transmission upgrades, is sufficient to ensure full dispatch of the proposal’s Clean Energy Generation profile.</p>
Bid fees Section 1.10	<p>The minimum bid fee is \$7,500 for a 20 MW bid, increased by \$375/MW to a maximum bid fee of \$100,000. For each price offer (above one), the bid fee will increase \$10,000 for projects of less than 100 MW in size and \$25,000 for all others.</p>
Allowable Pricing: PPAs Section 2.2.1.4	<p>Proposals to sell Clean Energy Generation and associated environmental attributes from Firm Service Hydroelectric Generation must be priced either (i) on a \$/MWh basis or (ii) indexed at or below the ISO-NE Locational Marginal Price at a defined pricing node on the PTF.</p> <p>Proposals to sell Clean Energy Generation and/or associated RECs from New Class I RPS eligible resources must be priced (i) on a \$/MWh basis or (ii) indexed at or below the ISO-NE Locational Marginal Price at a defined pricing node on the PTF. Separate pricing must be provided for energy and RECs. If the RECs cease to conform with RPS Class I eligibility criteria, the Distribution Companies may thereafter only pay for energy under the PPA. Pricing for Clean Energy Generation and RECs must closely align with the relative market value of these products.</p> <p>Alternative bids will be considered in which the Distribution Companies would obtain entitlements to RECs/environmental attributes from a Clean Energy Generation project for the life of the project, with payments to be made over the term of the long-term contract (15-20 years).</p>



Winter Months
Energy Delivery
Guarantee

Class I RPS eligible resources will be required to guarantee 70% of the energy in their delivery profile during the Winter Peak Period (7 am-11 pm, weekdays, excluding holidays, during the months of December through February).

Section 2.2.2.7

Firm Service Hydroelectric generation proposals will be required to submit a delivery profile with no Winter Peak Period hour less than 60% of the highest single hourly delivery proposed by the bidder, with delivery guaranteed during each hour in the Winter Peak Period.

Bidders not satisfying the guarantee will be responsible for liquidated damages for energy and associated RECs and environmental attributes not delivered, and as applicable, associated transmission infrastructure support costs.

Requirements
applicable to
transmission
proposals

Sections 2.2.1.4.ii,
2.2.2.6, 2.2.2.6.1,
2.2.2.6.2, and
2.2.2.6.3

Pricing for a transmission project should be proposed separately under a FERC-filed tariff.

Fixed prices are encouraged; cost of service pricing is allowed, but must include significant cost containment features. Bids that eliminate or limit customer risk to a greater degree will be evaluated more favorably. Cost containment features (protecting ratepayers from cost overruns) may include caps on project construction and capital costs, costs of related system upgrades, interconnection costs, and operations and maintenance costs.

If a transmission project accepted under this RFP is cancelled or abandoned, or its development is otherwise discontinued, the bidder shall be allowed to propose to recover prudently-incurred project-related costs ("abandonment costs") from the Distribution Companies in accordance with FERC rules and policies except that in no event may a bidder recover abandonment costs if the abandonment was caused directly or indirectly by some act or failure to act of the bidder.

The evaluation process will value more favorably proposals to the extent that the proposals eliminate or minimize ratepayer exposure to abandonment cost risk by not seeking abandonment cost recovery or including significant limitations, such as a proposal agreeing not to seek recovery for abandonment costs incurred prior to the issuance of this RFP, or a date certain to be proposed by the bidder.

In the event that generation as part of a packaged bid with transmission does not show up in accordance with a bidder's baseline schedule, transmission



payments will be reduced in proportion to the shortfall. The Evaluation Team will consider other mechanisms as proposed by the bidder to mitigate ratepayer risk. The evaluation process will evaluate more favorably proposals that include mechanisms to protect ratepayers from risks associated with payment for transmission costs when any associated expected Clean Energy Generation, as proposed by the bidder, is absent, reduced, or curtailed as compared to the baseline schedule.

Other threshold requirements

Sections 2.2.2 through 2.2.13

Bidders with generation proposals must demonstrate control over the site (which may be by option rights) for the generation project, including rights necessary to access the site. Bidders with transmission proposals must demonstrate a reasonable and achievable plan for obtaining site control for the transmission project.

Bidders must demonstrate the technical and financial viability of their proposed projects.

Bidders must demonstrate that they have sufficient relevant experience and expertise to successfully develop, finance, construct and operate the proposed project.

Bidders must show that the proposed project will “provide enhanced electricity reliability within the commonwealth,” as required by 83D.

Bidders must demonstrate that they can develop, finance, and construct their proposed project within a commercially reasonable timeframe.

Bidders must demonstrate that they will utilize an appropriate tracking system to account for the delivery of clean energy.

Bidders must demonstrate that a long-term contract will facilitate the financing of their proposed project. The bidder may specify how a long-term contract would permit it to finance a proposal that would otherwise not be financeable or assist it in financing of its proposal.

Security

Section 2.2.2.11

For RPS Class I Renewable Generation Units, the required level of contract security is \$20,000 multiplied by the maximum allowable energy delivery in MWh per hour (\$2 million for 100 MW), with 50% due on contract execution and the remaining 50% due after regulatory approval.



For hydroelectric generation, the required security is similar, except additional security may be required after regulatory approval is received based on market exposure.

The required level of security for transmission projects is \$10,000 per MW, with 50% due on selection and 50% due upon FERC acceptance of the rate schedule or tariff and service agreement.

Proposal
evaluation—Stage
Two

Section 2.3

Proposals that meet threshold requirements (Stage One evaluation) will be subject to a quantitative and qualitative evaluation in Stage Two. Stage Two scoring will be based on a 100-point scale, with 75 points for quantitative factors and 25 points for qualitative factors. The product of the analysis will be a relative ranking and scoring of proposals.

Quantitative
Evaluation

Section 2.3.1

The Evaluation Team may conduct an initial screening and may determine (by consensus) that one or more proposals are not economically competitive. Proposals that proceed to the quantitative evaluation will be evaluated on their direct and indirect economic and environmental costs and benefits based on a combination of their direct contract price cost and benefits and other costs and benefits to retail customers where applicable.

Direct costs are the costs to be paid by the Distribution Companies for generation and/or transmission (including upgrade costs associated with transmission). Direct benefits will include the projected revenues from the sale of energy and RECs based on forecasted market prices and any revenue from sales of excess transmission capacity, if applicable.

Other benefits and costs may include but not be limited to:

- The impacts of changes in LMP paid by customers in the Commonwealth and/or impact on production costs;
- The environmental attributes of generation from incremental hydroelectric generation and new Class I RPS eligible resources using an economic proxy value for contribution to GWSA requirements, and any additional impacts on the overall ability to meet GWSA requirements;
- Economic impacts associated with resource firmness; and
- Indirect impacts, if any, for retail customers on the capacity or ancillary services markets with the proposed project in service.



The evaluation process will include an evaluation of benefits using the outputs from an electric market simulation model. For purposes of computing net present value, a discount factor consisting of the weighted average value of the Distribution Companies' cost of capital will be used.

Qualitative
Evaluation

The qualitative evaluation will consist of factors mandated by 83D as well as other factors considered important by the Evaluation Team. These include:

Section 2.3.2

- Project viability;
- Extent to which the project can support the Commonwealth's GWSA requirements by delivering Clean Energy Generation and/or RECs or environmental attributes on or before December 31, 2020;
- Siting and permitting;
- Reliability benefits;
- Price risk/price firmness;
- Environmental impacts from siting;
- Economic benefits to the Commonwealth;
- Extent to which proposals combine new Class I renewable resources and firm hydroelectric generation and demonstrate a benefit to low-income ratepayers in the Commonwealth without adding cost to the project.

Following the State Two Evaluation, the Evaluation Team will determine which proposals proceed to the Stage Three evaluation based on the following considerations: (1) the rank order of the proposals at the end of the Stage Two evaluation; (2) the cost effectiveness of the proposals based on the Stage Two quantitative evaluation; and (3) the total annual MWh/year quantities of the proposal(s), relative to the annual procurement target.

Stage Three
Evaluation

In Stage Three the Evaluation Team will evaluate the remaining proposals based on the Stage Two evaluation criteria and, at their discretion, the following additional factors:

Section 2.4

Portfolio effect:

- Overall impact of various portfolios of proposals on the Commonwealth's policy goals, as directed by the DOER, including GWSA goals
- Overall cost effectiveness of various portfolios of proposals



Risks associated with project viability of the proposals

Any risks to customers that may be associated with projects proposing to recover transmission costs through transmission rates not fully captured in the Stage Two evaluation

Any benefits to customers that may not have been fully captured in the Stage Two evaluation

Any other considerations, as appropriate, to ensure selection of the proposal(s) which provide the greatest impact and value consistent with the stated objectives and requirements of Section 83D, as set forth in this RFP.

Under Section 83D, if the Distribution Companies are unable to agree on the selection of proposals among themselves, then the DOER, in consultation with the Independent Evaluator, shall make the final binding determination of the winning bid(s).

Contracting Process;
Regulatory
Approvals

The Distribution Companies will negotiate to contract with selected bidder(s) based on their load ratio share. With regard to any transmission tariff or contract, allocation of rights and obligations will also be based on the Distribution Companies' load ratio share.

Sections 2.5, 2.6

The Distribution Companies intend to submit any long-term contract for Department regulatory approval within 45 days of executing a long-term contract; Department regulatory approval is required for the contract to become effective. Any FERC-jurisdictional rate schedule or tariff and service agreement agreed upon by the Distribution Companies will be filed with FERC under Section 205 of the Federal Power Act, which must be accepted by FERC before becoming effective.

RFP Schedule

Section 3.1

The proposed schedule covers a 13-month period, with the following anticipated dates (which are subject to change):

- Issue RFP – 3/31/2017
- Bidders conference – 4/14/2017
- Submit notice of intent to bid—4/21/2017
- Deadline for bidder submission of questions—4/21/2017
- Proposals Due – 7/27/2017
- Selection of projects for negotiation – 1/25/2018



- Finalize contract negotiations – 3/27/2018
- Submit contracts for Department approval – 4/25/2018

Role of the
Independent
Evaluator

The role of the Independent Evaluator is described in Section 1.5 of the proposed RFP.

Section 1.5

Bidder Certification

Section 1.8

Each bidder is required to certify, with submission of its proposal, that, *inter alia*, it has no knowledge of confidential information associated with development of this RFP and, except as disclosed in relevant portions of its response, the bidder is not an affiliate of any Distribution Company and no Distribution Company has a financial or other affiliate interest in the bidder or the bidder's proposed project.

Information
Required of Bidders

Appendix B

The RFP contains a Bidder Response Package (Appendix B) which contains information requests for bidders; each bidder was required to provide its responses to the Appendix B questions as part of its proposal. Appendix B was been provided with the proposed RFP; a Certification, Project and Pricing data form (Excel format), in which bidders are required to provide proposed pricing and forecasted generation is described but not included in Appendix B and was posted on the RFP website.

Forms of
Agreements

Appendix C;
Appendix B,
Section 15.

Forms of PPAs for the three types of generation proposals were posted on the RFP website following Department approval of the issuance of the RFP. Also posted was a document summarizing provisions to be included by bidders for proposed transmission service agreements.

PPA bidders were required to state any exceptions and include specific alternative language to the applicable form PPAs.

Transmission bids were required to contain a proposed transmission agreement and contain a summary of material provisions.

Utility Standard of
Conduct

Eversource and National Grid posted standards of conduct on the RFP website. Generally, they provide for separation, and prohibit communication between, an



Appendix G

Evaluation Team and a Bid Team, with respect to the RFP and solicitation process.



APPENDIX C
BIDS THAT DID NOT MEET THRESHOLD/ELIGIBILITY REQUIREMENTS

[illegible]

APPENDIX D

LARGE PROJECTS: STAGE 2 EVALUATION

Table 1: Summary of the 2022-2023 Hydroelectric Bidding Process																
Bid No.	Project	Bidder(s)	Max.	Proposal Type	Generator Location	Delivery Zone	Start Date	Proposal Cost (PPA + Transm.)*	GWh/ year	Net Direct Benefit*	Net Indirect Benefit*	Net Total Benefit*	Net Benefit NPV\$ (000)	Quant. Score	Qual. Score	Total Score
			Contract Amt. (MW)													
										\$23.23	\$23.24	\$46.47	\$2,049,673	75.00	10.94	85.94
										\$22.26	\$19.92	\$42.18	\$1,664,569	68.08	12.16	80.24
	40 NECEC Hydro	HRE/CMP	1090	Hydro/transm.	Quebec	ME	12/31/2022	\$59.34	9,555	\$15.41	\$24.32	\$39.73	\$3,875,670	64.12	15.63	79.75
										\$10.31	\$25.87	\$36.18	\$3,890,386	58.38	18.25	76.63
										\$9.63	\$26.08	\$35.71	\$3,284,303	57.62	18.13	75.75
										\$8.97	\$26.08	\$35.05	\$3,223,570	56.56	19.13	75.69
										\$15.40	\$21.07	\$36.47	\$3,557,166	58.86	15.68	74.54
										\$9.63	\$23.99	\$33.62	\$3,606,849	54.25	16.98	71.23
										\$8.55	\$22.72	\$31.27	\$2,876,789	50.47	18.14	68.61
										\$7.89	\$22.72	\$30.61	\$2,816,055	49.41	19.14	68.55
										\$10.27	\$23.24	\$33.51	\$1,477,913	54.08	9.85	63.93
										\$16.21	\$12.59	\$28.80	\$564,722	46.47	12.16	58.63
										\$3.06	\$22.46	\$25.52	\$1,508,211	41.19	9.31	50.50
										\$16.76	\$5.83	\$22.59	\$519,171	36.46	13.69	50.15
										\$15.62	(\$6.86)	\$8.76	\$253,627	14.14	12.79	26.93
										\$12.64	(\$5.52)	\$7.12	\$206,097	11.49	14.04	25.53
										(\$7.30)	\$15.77	\$8.47	\$238,200	13.67	9.75	23.42

* Costs and Net Benefits are in 2017 Real \$/MWh Levelized

REDACTED

D.P.U. 18-64/18-65/18-66

IIJJJ69

APPENDIX E
SMALL PROJECTS: STAGE 2 EVALUATION

Bid No.	Project	Bidder(s)	Max. Contract Amt. (MW)	Technology	Generator Location	Delivery Zone	Start Date	Proposal Cost (PPA + Transm.)*	GWh/ year	Net Direct Benefit*	Net Benefit NPV\$ (000)	Quant. Score	Qual. Score	Total Score
										\$27.89	\$93,359	75.00	12.25	87.25
										\$21.71	\$253,650	58.38	11.00	69.38
										\$17.33	\$119,890	46.60	18.75	65.35
										\$13.71	\$107,547	36.87	10.00	46.87
										\$12.98	\$8,057	34.92	10.00	44.92
										\$9.86	\$760,807	26.51	12.13	38.64
										\$10.34	\$141,781	27.81	10.00	37.81
										\$10.52	\$91,957	28.29	9.25	37.54
										\$9.11	\$35,761	24.51	10.00	34.51
										\$7.25	\$52,054	19.49	10.00	29.49
										\$5.85	\$20,603	15.72	10.00	25.72
										\$2.14	(\$8,189)	5.76	10.50	16.26
										\$1.08	\$21,284	2.91	10.00	12.91
										(\$0.26)	\$22,471	-0.70	10.50	9.80
										(\$0.86)	\$625,904	-2.32	10.25	7.93
										(\$7.79)	\$27,371	-20.96	10.00	-10.96
										(\$18.67)	\$169,744	-50.22	10.00	-40.22
										(\$31.97)	\$227,793	-85.99	7.31	-78.68
										(\$36.68)	(\$5,768)	-98.65	10.00	-88.65
										(\$37.99)	(\$51,283)	-102.17	0.00	-102.17
										(\$48.28)	(\$574,031)	-129.85	10.50	-119.35

* Costs and Net Benefits are in 2017 Real \$/MWh Levelized

Appendix F: Stage 3 Portfolio Summary															
Proposal/Portfolio	Portfolio Number/ Description	Capacity--MW Installed	Technology	Delivery Location ISO-NE Zone	Start Date	Contract Cost* PPA + Transm.	Annual Energy GWh	Net Direct Benefit*	Net Indirect Benefit*	Net Total Benefit*	Net Benefit NPV \$(000)	Quant. Score	Qual. Score	Total Score	Rank
NECEC Hydro**	Portfolio 6	1090	Hydro	ME	12/31/2022	\$59.05	9,555	\$15.70	\$24.32	\$40.02	\$3,903,686	75.00	15.63	90.63	1
	Portfolio 12							\$15.96	\$22.47	\$38.43	\$3,879,300	72.02	15.50	87.52	2
	Portfolio 3							\$15.59	\$21.89	\$37.48	\$3,900,618	70.24	15.39	85.63	3
	Portfolio 8							\$9.74	\$25.87	\$35.61	\$3,829,761	66.74	18.25	84.99	4
	Portfolio 9							\$8.97	\$26.08	\$35.05	\$3,223,570	65.69	19.13	84.82	5
	Portfolio 7							\$15.69	\$21.07	\$36.76	\$3,585,182	68.90	15.68	84.58	6
	Portfolio 14							\$9.32	\$25.16	\$34.48	\$3,314,317	64.64	18.87	83.51	7
	Portfolio 5							\$9.30	\$23.32	\$32.62	\$3,255,600	61.14	18.55	79.69	8
	Portfolio 10							\$7.89	\$22.72	\$30.61	\$2,816,055	57.38	19.14	76.52	9
	Portfolio 4						8,317	\$17.96	\$11.33	\$29.29	\$2,616,587	54.90	11.45	66.35	10
	Portfolio 2							\$15.70	\$9.91	\$25.61	\$2,550,522	47.99	11.30	59.29	11
	Portfolio 13							\$20.24	\$4.62	\$24.86	\$2,733,562	46.59	11.85	58.44	12
NECEC Hydro Delay	Portfolio 6 Sensitivity	1090	Hydro	ME	12/31/2023	\$57.90	9,555	\$18.65	\$22.81	\$41.46	\$3,854,921				
								\$10.85	\$25.87	\$36.72	\$3,948,938				
								\$10.29	\$25.87	\$36.16	\$3,888,747				
								\$13.16	\$24.89	\$38.05	\$3,892,475				
								\$14.24	\$24.89	\$39.13	\$4,003,083				
* Real Levelized 2017\$/MWh															
** NECEC Hydro	Escalating Transmission Rate	1090	Hydro	ME	12/31/2022	\$58.92	9,555	\$15.83	\$24.32	\$40.15	\$3,916,299				
** NECEC Hydro	HQ Deliveries of 110 MW	1200	Hydro	ME	12/31/2022	\$58.92	9,555	\$15.42	\$26.37	\$41.79	\$4,076,609				
** These evaluations were conducted after selection and would not have affected the ranking of the NECEC Hydro proposal:															
Escalation Transmission Rate: TCR discovered and corrected an error on CMP's escalating transmission rate proposal; this is the proposal reflected in the executed Transmission Service Agreement															
HQ Deliveries of 110 MW: Assumed that HQUS would deliver 110 MW on a baseload basis using its rights on the NECEC transmission line															

APPENDIX G: STAGE 3 PORTFOLIO SUMMARY--SCORING BASED ON ALTERNATIVE \$NPV QUANTITATIVE EVALUATION METRIC AS REPORTED BY DOER															
Proposal/Portfolio	Portfolio Number/ Description	Capacity--MW Installed	Technology	Delivery Location ISO-NE Zone	Start Date	Contract Cost* PPA + Transm.	Annual Energy GWh	Net Direct Benefit*	Net Indirect Benefit*	Net Total Benefit*	Net Benefit NPV \$(000)	Quant. Score	Qual. Score	Total Score	
NECEC Hydro***	Portfolio 6	1090	Hydro	ME	12/31/2022	\$59.05	9,555	\$15.70	\$24.32	\$40.02	\$3,903,685	75.00	15.63	90.63	
NECEC Hydro Delay	Portfolio 6 Sensitivity	1090	Hydro	ME	12/31/2023	\$57.90	9,555	\$18.65	\$22.81	\$41.46	\$3,854,921	74.06	15.63	89.69	
	Portfolio 3														
	Portfolio 12														
	Portfolio 7														
	Portfolio 14														
	Portfolio 5														
	Portfolio 9														
	Portfolio 10														
	Portfolio 13														
	Portfolio 4														
	Portfolio 2														
* Real Levelized 2017\$/MWh															
*** NECEC Hydro	Escalating Transmission Rate	1090	Hydro	ME	12/31/2022	\$58.92	9,555	\$15.83	\$24.32	\$40.15	\$3,916,299				
*** NECEC Hydro	HQ Deliveries of 110 MW	1200	Hydro	ME	12/31/2022	\$58.92	9,555	\$15.42	\$26.37	\$41.79	\$4,076,609				
*** These evaluations were conducted after selection															
Escalation Transmission Rate: TCR discovered and corrected an error on CMP's escalating transmission rate proposal: this is the proposal reflected in the executed Transmission Service Agreement															
HQ Deliveries of 110 MW: Assumed that HQUS would deliver 110 MW on a baseload basis using its rights on the NECEC transmission line															