PUBLIC VERSION (REDACTED)

NECEC TRANSMISSION PROJECT: BENEFITS TO MAINE RATEPAYERS

Quantitative & Qualitative Benefits

SEPTEMBER 27, 2017

PREPARED FOR

Central Maine Power

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EXECUTIVE SUMMARY

Central Maine Power (CMP or the Transmission Sponsor) has proposed to build the New England Clean Energy Connect Transmission Project (NECEC Transmission Project) as part of an offering of two project bids (NECEC Project Bids) in response to the "*Request for Proposals for Long-Term Contracts for Clean Energy Projects*" (Massachusetts RFP) issued jointly by the Massachusetts Department of Energy Resources (MA DOER) and the Distribution Companies of the Commonwealth of Massachusetts[1], collectively referred to herein as the Soliciting Parties.

Each bid requires the construction of the NECEC Transmission Project in order to deliver clean energy to Massachusetts via the CMP transmission system from the point of delivery in Lewiston, Maine. At no cost to Maine ratepayers, each bid will, as a consequence of providing clean energy to Massachusetts, result in significant benefits to Maine ratepayers, as well. The significant benefits to Maine ratepayers are the focus of this report.

A. NECEC Transmission Project

The NECEC Transmission Project provides for the reliable delivery of up to 1,200 megawatts (MW) of energy per hour into the New England grid. The total cost of the project will be paid for in two ways. The NECEC Project Proponents[2] have included the cost of [redacted] MW of the transmission capacity from the NECEC Transmission Project as part of their bid. This represents the portion of the transmission capacity needed to deliver the clean energy included in their bid. Hydro Renewable Energy, Inc., an affiliate of Hydro-Québec, has agreed to be financially responsible for the remaining [redacted] MW of transmission capacity on the line. None of the cost of the NECEC Transmission Project will be borne by Maine ratepayers.

B. NECEC Project Bids to Massachusetts

The two NECEC Project Bids (collectively referred to as Bids, individually as Bid 1 and Bid 2) have been offered as separate and exclusive offers to deliver a minimum of [redacted] gigawatt-hours (GWh) and up to [redacted] GWh of clean energy generation per year, each to be delivered via the NECEC Transmission Project to a delivery point at the existing Larrabee Road substation in Lewiston, Maine.

Bid 1 includes firm delivery of incremental hydroelectric generation, and Bid 2 includes Class I RPS eligible energy from [redacted] MW of new wind generation, firmed by incremental hydroelectric generation.

[1] Per Section 1.1 of the Massachusetts RFP, the Distribution Companies are: Fitchburg Gas & Electric Light Company d/b/a Unitil, Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, NSTAR Electric Company and Western Massachusetts Electric Company d/b/a Eversource.

[2] The NECEC Project Proponents includes CMP, Hydro Renewable Energy, Inc., and SBx, a joint venture of Gaz Metro Limited partnership (Gaz Metro) and Boralex Inc. (Boralex).

C. NECEC Benefits to Maine Ratepayers

The Transmission Sponsor retained Daymark Energy Advisors (Daymark) to evaluate the NECEC Project and provide an analysis of the benefits of the project to Maine ratepayers associated with the public benefits determination required for a Certificate of Public Convenience and Necessity (CPCN) from the Maine Public Utilities Commission (the Commission). This report and its associated appendices provide Daymark's estimation of these benefits, as well as our methodology and assumptions used to derive the benefit values.

The benefits analyzed are:

- Energy and Capacity price impacts;
- Greenhouse gas (GHG) reductions;
- Additional hedging benefits;
- Impacts on Ancillary Services; and
- Other benefits.

Price Impacts

In consideration of a CPCN petition, the Commission may consider many factors, including the economics associated with the proposed project.[3] In addition, Maine has a long-established goal of reducing energy prices and volatility for ratepayers in Maine.[4] The delivery of low-cost, firm power will exert downward pressure on both energy and capacity market clearing prices throughout New England. While Massachusetts Distribution Companies are contracting for the energy, all New England ratepayers will see lower energy prices with the NECEC Project in place due to the reduction in locational marginal prices (LMPs) system-wide.

Depending on the amount of energy ultimately delivered by the NECEC Project, Maine ratepayers will benefit from between $40 million and $44 million annually in levelized LMP savings. The LMP reduction and cumulative NPV benefits of both the minimum contract and the additional clean energy potential can be seen in Figure 1.[5]

Considering only the assumed additional energy associated with the RFP contract, Maine ratepayers will yield levelized benefits of $40 million per year (present value $454 million) resulting from LMP reductions averaging $3.38/MWh. When including energy from the full capacity of the line, the additional energy that may be imported on a market price basis will increase total benefits to Maine ratepayers $44 million per year (present value $496 million) resulting from LMP reductions averaging $3.70/MWh.

[3] 35-A M.R.S. § 3132(6).

[4] CPCN Petition, Section IV.B.3. provides a detailed discussion of Maine policy regarding energy prices and volatility.

[5] Present value savings are provided in 2023 dollars, the first full year the project is expected in service.

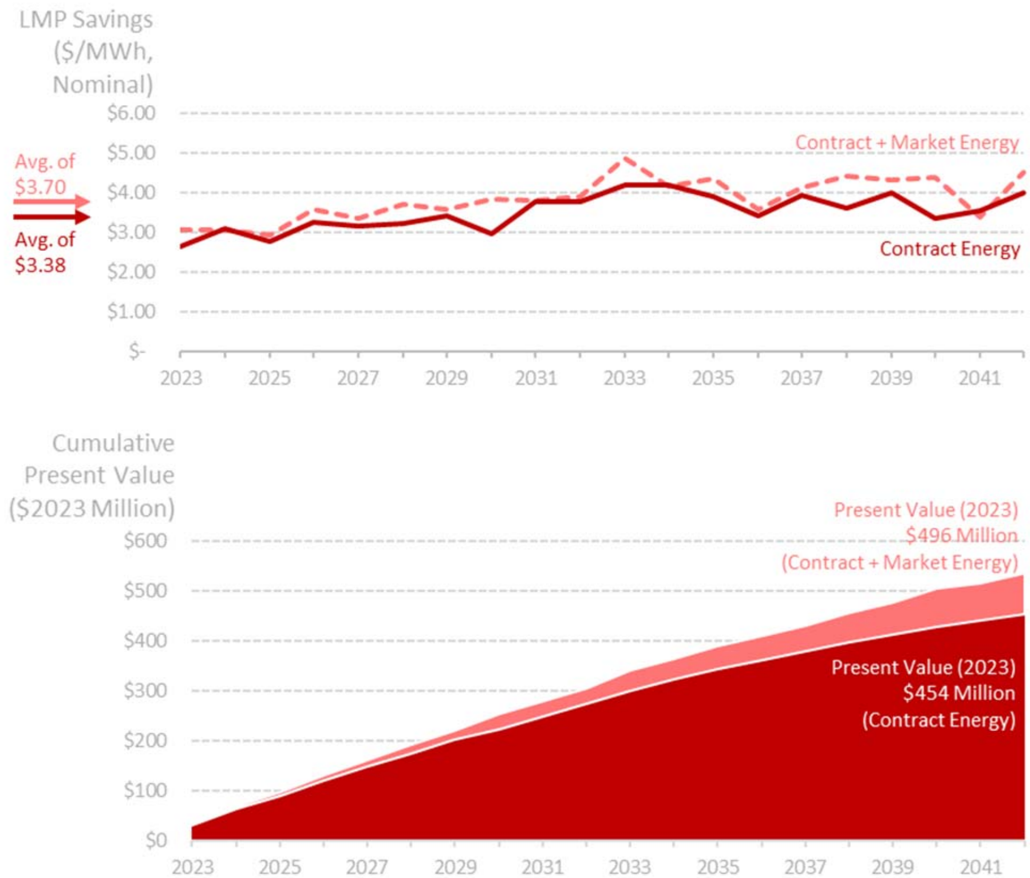

Figure 1. LMP Savings Benefit ($/MWh) and Present Value of Cumulative Benefit to ME Ratepayers ($2023 Millions).

Greenhouse Gas Reductions

Maine has established public policies and actions to mitigate climate change by reducing greenhouse gas (GHG) emissions.[6] As a large source of non-emitting generation, the NECEC Project will help contribute to Maine's efforts to achieve its policy goals.

The NECEC Project will provide clean, inframarginal energy, displacing significant generation from primarily GHG-emitting resources in the ISO New England (ISO-NE) system. Our analysis concludes that the NECEC Project will induce annual CO_2 emission reductions of approximately 3.1 million metric tons across New England. As a result, the net emissions from the portion of regional generation serving Maine load is reduced by approximately 264,000 metric tons per year.

6 CPCN Petition, Section IV.B.2. provides a detailed discussion of Maine GHG reduction policy.

Additional Hedging Benefits

The generation portfolio in ISO-NE has become dominated by natural gas in recent years. Natural gas provides nearly half of the total electric energy produced in New England and is the marginal fuel setting electric market prices in more than three-fourths of the year.[7] As a result, volatility in the cost of fuel has exposed ratepayers in Maine and across the region to higher electric energy prices when the natural gas prices are high. The addition of a large source of firm, unconstrained, low-cost renewable energy and capacity provides a valuable hedge against natural gas price swings.

Energy from the NECEC Project reduces the portion of the resource mix that is subject to fluctuating fuel prices, allowing greater market flexibility under high gas prices that can drastically impact energy prices. As natural gas prices impact energy prices system-wide, the hedging benefits will be shared by Maine ratepayers, as well as ratepayers throughout the region.

On the capacity side, the ISO-NE capacity market may be experiencing thermal and nuclear resource retirements in the coming years, potentially exposing ratepayers to capacity price escalation. The NECEC Project also represents incremental clean, low-cost capacity that provides hedging benefits in the capacity market.

Impacts on Ancillary Services

Backed by Hydro-Québec's significant hydroelectric facilities, the resources available to provide the clean energy under the NECEC contract will be available in all hours. This firmness provides several benefits to the New England Ancillary Services markets. Firm power will provide strong value by being available when it is most needed, such as in stress conditions due to high load or outages. The firm power of the NECEC Project may also free up other resources to provide more reserve or other ramping capabilities, ensuring a more robust grid.

Ancillary services are centrally coordinated and procured by ISO New England, with load in each state paying for its proportional share of the costs. By providing firm energy, the NECEC Project will likely reduce the cost of providing ancillary services to the grid. Maine ratepayers will benefit proportionally from the consequent reduction in ISO-NE ancillary services costs.

[7] *2016 Annual Markets Report, ISO New England's Independent Market Monitor*, May 30, 2017. The IMM reports that, in 2016, 49% of total generation was fired by natural gas (page 14) and was the marginal fuel 77% of the time (page 91).

Other Benefits

The NECEC Project provides several other benefits to Maine ratepayers, including the following:

Reduction in Natural Gas Consumption

The NECEC Project will help displace some natural gas consumption. This is particularly impactful in winter months, when gas pipeline constraints can have severe impacts on pricing for electricity generation.

Congestion

The NECEC Transmission Project includes system upgrades sufficient to ensure deliverability of the energy and capacity to southern New England. The project creates virtually no congestion and allows the full delivery of the energy and capacity.

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ACRONYMS AND DEFINED TERMS

AEO	Annual Energy Outlook
AURORA	AURORAxmp®
CMP	Central Maine Power
CPCN	Certificate of Public Convenience and Necessity
Daymark	Daymark Energy Advisors
Distribution Companies	Distribution Companies of the Commonwealth of Massachusetts
EIA	U.S. Energy Information Administration
ETU	Electric transmission upgrade
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
GHG	Greenhouse gas
GWh	Gigawatt hours
GWSA	Global Warming Solutions Act
HRE	Hydro Renewable Energy
HVDC	High Voltage Direct Current
IMM	Internal Market Monitor
Incremental Transmission Capacity	Remaining [redacted] MW of transmission capacity on the line
LCOE	Levelized cost of energy
LDCs	Local Distribution Companies
LMP	Locational Marginal Price
MA DOER	Massachusetts Department of Energy Resources
MassDEP	Massachusetts Department of Environmental Protection
MMBtu	Millions of British Thermal Units
MW	Megawatts
MWh	Megawatt hours
NECEC Project	New England Clean Energy Connect
NECEC Wind Developer	A Joint venture of Gaz Metro Limited Partnership and Boralex Inc.
Net CONE	Net Cost of New Entry
NPV	Net present value
REC	Renewable energy credit
Solar PV	Solar photovoltaic
Soliciting Parties	MA DOER and Distribution Companies
Transmission Sponsor	Central Maine Power

I. INTRODUCTION

A. The NECEC Transmission Project

The Transmission Sponsor is proposing, as part of the NECEC Project Bids discussed below, to develop the NECEC Transmission Project designed to reliably deliver the clean energy from either Bid to Massachusetts and the region.

The NECEC Transmission Project consists of a high voltage direct current (HVDC) transmission line that runs from the Québec-Maine border in Beattie Township to a substation in the Lewiston area, a new HVDC converter station and related alternating current (AC) interconnection facilities in Lewiston, and all related transmission network upgrades on the U.S. side of the border. The NECEC Transmission Project includes upgrades to the AC transmission system in Maine that will increase the transfer capability at the Surowiec-South interface by approximately 1,000 MW and provide a pathway for up to 1,200 MW of new clean energy resources from Québec via the proposed HVDC transmission line.[8]

B. The NECEC Projects Bids to Massachusetts

Each Bid offers a minimum of [redacted] GWh and up to [redacted] GWh of firm service clean energy to be delivered to Massachusetts.

In Bid 1, Hydro Renewable Energy LLC (HRE)[9] provides the energy being delivered to Massachusetts ratepayers from incremental hydroelectric resources at a fixed price for energy and transmission.

In Bid 2, SBx, a joint venture of Gaz Metro Limited Partnership and Boralex Inc. (collectively, the "NECEC Wind Developer") provides [redacted] MW of Class I qualifying wind generation, producing 1,100 GWh of clean energy generation and 1.1 million renewable energy credits (RECs) backed by firm service hydroelectric generation. The remaining clean energy generation is hydroelectric energy offered by HRE. Bid 2 is also a fixed price to Massachusetts for energy, RECs and transmission.

The NECEC Project Bids include the use of and the cost for sufficient NECEC Transmission Project transfer capability to deliver the contracted energy without constraint. HRE has agreed to pay for any remaining MW of the Transmission Project capacity, which will be available to HRE to deliver additional energy and capacity to the New England. This could include additional deliveries of clean energy to the Soliciting Parties or to others in the New England market. Thus, all the transmission cost will be borne by Massachusetts or HRE and none of the cost will be borne by Maine ratepayers.

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[8] For a full description of the NECEC Transmission Project attributes, refer to the NECEC CPCN Petition, Section V.

[9] HRE is an affiliate of Hydro-Québec.

C. Evaluation of NECEC Project Benefits to Maine Ratepayers

This report presents the results of our evaluations of the economic and environmental benefits that will accrue to Maine ratepayers from the development of the NECEC Project and is presented for consideration by the Commission in the evaluation of the NECEC CPCN submission.

Our quantitative analysis simulates the regional electric market operations, comparing market price and environmental performance changes in cases with and without the NECEC Project. This analysis uses a current Reference Case analysis in a zonal model of the regional markets using the AURORAxmp® (AURORA) software. Using this model, we provide quantitative analysis to assess the impact of the NECEC Project Bids on regional market prices, production cost, GHG emissions, and congestion at key interfaces in the region.

For purposes of this report, the amount of contracted energy was assumed to be 8,600 GWh, derived from a contracted capacity of [redacted] MW, operating at a [redacted] capacity factor. This was modeled as 981 MW of clean energy delivered over the NECEC Transmission Project in each hour. Except where noted, no additional energy from the last [redacted] MW of transmission reservation was included in the determination of benefits. There are additional benefits to Maine ratepayers that will likely result from this extra [redacted] MW of capacity.

D. Maine CPCN and Public Policy Objectives

This report supports the Transmission Sponsor's CPCN petition. In considering the petition, Maine's CPCN statute requires the Commission to consider a variety of factors, including economics, reliability, public health and safety, scenic, historic and recreational values, state renewable energy generation goals, the proximity of the proposed transmission line to inhabited dwellings, and alternatives to construction of the transmission line, including energy conservation, distributed generation or load management.[10]

In addition, Maine has established public policies of lowering electricity prices for the benefit of customers, as well as public policies to encourage development of renewable energy resources and to reduce greenhouse gas emissions to mitigate the effects of climate change.

This report demonstrates the value of the NECEC Project in the context of several of these CPCN factors and public policies, as described below.

Electric Energy Price Reductions

The Maine CPCN statute lists "economics" as a primary factor in considering a petition. In addition, Maine has a long-established goal of reducing energy prices and volatility for ratepayers in Maine.[11]

[10] 35-A M.R.S. § 3132(6).

[11] See, e.g. Maine's capacity resource adequacy statute, 35-A M.R.S. § 3210-C(2). See also the 2013 Maine Energy Cost Reduction Act, P.L. 2013, Ch. 369, Part B (codified at 35-A M.R.S. § 1901 *et seq.*).

As our analysis shows, the provision of nearly 1,000 MW of low-cost, firm power will exert downward pressure on both energy and capacity market clearing prices throughout New England. Market prices in central Maine will be most directly affected, as the ISO New England energy market design is locational, causing reduced market prices at the delivery point and in Maine pricing zones. Analysis of the impact on energy and capacity market clearing prices is discussed in Section III.

GHG Reductions

In addition to the goal of reducing energy prices, Maine has established public policies to support of the reduction of GHG. In 2003, the Maine Legislature enacted the Act to Provide Leadership in Addressing the Threat of Climate Change (the "Climate Change Act"), which established GHG reduction goals for 2010, 2020, and beyond. As part of that Act, Maine set the following objectives:

- In the short term, by January 1, 2010 to 1990 levels;
- In the medium term, by January 1, 2020 to 10% below 1990 levels; and
- In the long term, reduction sufficient to eliminate any dangerous threat to the climate. To accomplish this goal, reduction to 75% to 80% below 2003 levels may be required.

In addition, Maine participates in the Regional Greenhouse Gas Initiative (RGGI) CO_2 Cap-and-Trade Program, which establishes multistate CO_2 budgets designed to reduce regional GHG emissions.

The NECEC Project contributes to these goals by inducing reductions in GHG emissions region-wide. Our analysis quantifies these benefits in Section IV.

Renewable Energy

Maine has a mandatory Renewable Portfolio Standard (RPS) requiring any competitive energy provider (CEP) serving load in Maine to procure Class I RECs at an increasing percentage of its portfolio over time. The required percentage currently tops out at 10% from "new" resources[12] in 2017. NECEC Bid 2 includes significant generation from Class I qualifying wind resources. While the RECs associated with the contracted energy would be committed to Massachusetts for the contract term, there may be the potential for additional Class I energy to be imported over any portion of the NECEC Transmission Project not contracted for under the Massachusetts RFP.

To the extent that load growth, changes in Maine RPS policy, or retirement of other REC producing resources lead to future needs for Maine CEPs, the addition of incremental REC supply to the regional REC markets also may produce a future beneficial effect for Maine ratepayers.

[12] 35-A M.R.S. § 3210(3-A)

II. EVALUATION METHODOLOGY

This section provides a description of the analysis methodology used to conduct our evaluation of the NECEC Transmission Project and associated clean energy Bids. We evaluated the broad range of benefits of the NECEC Project to Maine. The models, evaluation methodology, and key assumptions are described in this section.

A. Methodology & Tools Used

The quantification of benefits of the NECEC Project is derived from analysis using the AURORAxmp® zonal model for the Eastern Interconnect (AURORA), developed by EPIS, Inc. The results of the market simulation performed with AURORA provided the data upon which we relied to prepare estimates of the following benefits:

- Changes in LMPs and wholesale costs of energy for the ratepayers; and
- Reductions in greenhouse gas emissions in Maine.

Other benefits assessments were derived using our proprietary market modeling and spreadsheet models, including our New England Forward Capacity Market (FCM) model.

Appendices A, B, and C provide documentation of the models, methodologies, and assumptions used for the benefits evaluations presented in this report.

B. Key Assumptions

Our analysis relies on a set of Reference Case assumptions on future market conditions in New England. The analytical basis of our analysis reflects a reasonable set of reference assumptions, derived from public sources, including ISO-NE and the U.S. Energy Information Administration (EIA). The results of the modeling form the foundation of our analysis of the full range of benefits of the NECEC. This section provides summary-level descriptions of key assumptions and methods. Appendix A to this report provides a full description of our assumptions.

Natural Gas

Natural gas is the predominant marginal fuel in New England and is a significant factor in determining LMPs, wholesale energy costs, and production costs. Our analysis used natural gas price forecasts from the 2017 Annual Energy Outlook (AEO)[13] published by the EIA. The AEO forecasts used in this analysis include ISO-NE's Algonquin Citygates pricing index, the Henry Hub index, as well as the primary trading markets neighboring ISO-NE that are represented in our model.

For our Reference Case, we used the AEO's "Reference" forecasts. Figure 2 below depicts the key natural gas price assumptions.

[13] https://www.eia.gov/outlooks/aeo/

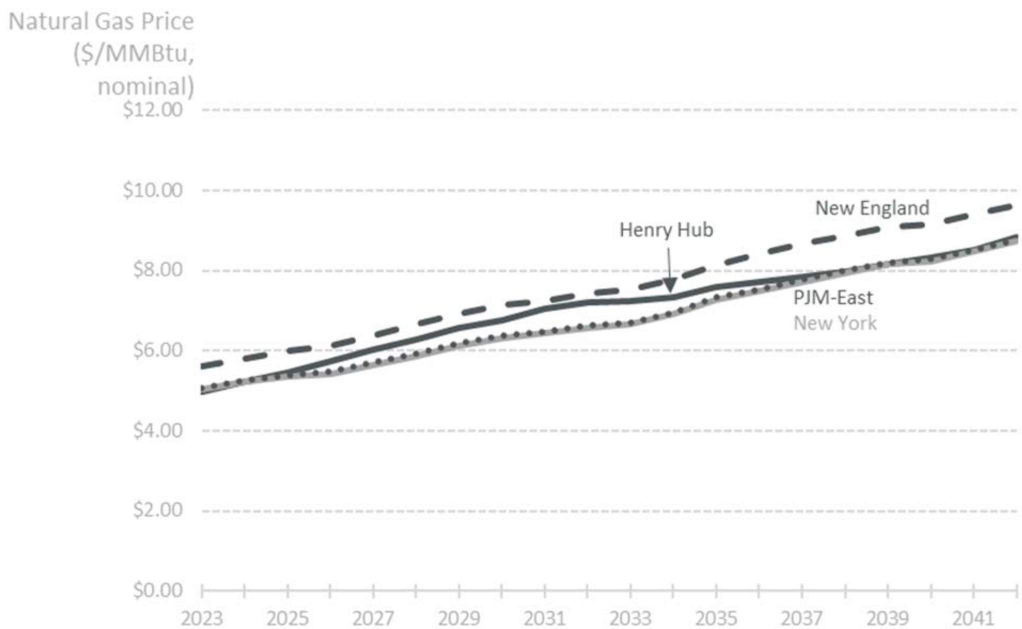

Figure 2. Natural Gas Price Assumptions ($/MMBtu, nominal)

Generator Additions and Retirements

Our analysis relies on assumptions of generator retirements and additions based on known and forecasted retirements and additions for generators in the ISO-NE market. The primary sources of the known resource designations are the results of the ISO-NE Forward Capacity Auctions (FCA), the most recent of which (FCA11) determined capacity obligations for the 2020-2021 commitment period. In addition to the generators that cleared in that most recent auction, further retirements and additions are based on results of analysis conducted with our New England FCM model. This model is described in Appendix C.

Renewable Resources

Our Reference Case assumptions of utility-scale renewable resources include all existing projects, projects currently under construction, and the approximately 460 MW of renewable projects selected under the 2015-16 Three State Clean Energy RFP jointly conducted by Massachusetts, Connecticut, and Rhode Island. These projects are all assumed to be in service by the beginning of the evaluation period. We have also assumed a total of 1,600 MW of new offshore wind capacity contracted under the upcoming Massachusetts Offshore Wind RFP[14], phased in as 400 MW tranches every other year beginning in 2024.

[14] For details on the MA Offshore Wind RFP see https://macleanenergy.com/83c/

In addition, we assumed a solar photovoltaic (solar PV) buildout that is consistent with the ISO-NE solar forecast conducted as part of the CELT report process, and a continued growth of distributed solar deployment for the years beyond the end of the ISO-NE forecast period.

III. PRICE IMPACTS

The NECEC Project includes the construction of a 1,200 MW HVDC line and the injection of firm clean energy into the New England markets. The addition of these firm, low-cost resources will have significant impacts on both the energy and capacity markets of ISO-NE.

A. Energy Market Impacts

Maine ratepayers will receive substantial energy market benefits from the NECEC Project. The cost of energy supply in Maine is based on the hourly ISO-NE Maine Load Zone LMP, which is derived from the more granular prices at dozens of load and generator nodes across the state. The addition of low marginal cost energy will deliver the greatest LMP reductions in nodal prices at and near the injection location (Larrabee Road in Lewiston, Maine), but will also reduce LMPs throughout the state and larger ISO-NE region.

We evaluated the energy market benefits of the NECEC Project Bids, and the potential additional energy, through market simulation with AURORA. As noted above, the NECEC Project Bids were simulated in the model as delivering 981 MW of clean energy each hour. For the analysis evaluating the potential benefits of the additional energy that could be delivered using the full capacity of the NECEC Transmission Project, the energy delivery was modeled as 1,086 MW of clean energy each hour.

By comparing simulations with and without the NECEC Project Bids in service, we quantified the change in LMPs that results from the incremental clean energy. This reduction in LMPs directly reduces the wholesale energy costs of serving New England customers. Figure 3 below depicts the cumulative NPV of LMP savings for each state in New England, corresponding to the lower estimate of delivered energy.

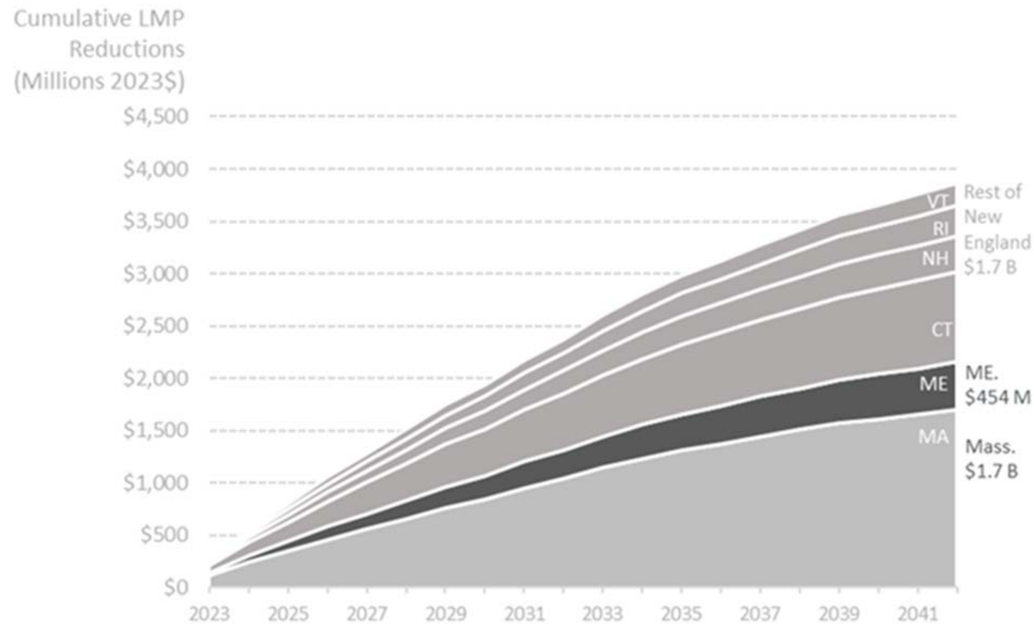

Figure 3. Cumulative LMP reductions by state, 981 MW Scenario

Figure 4 below depicts the reductions in Maine LMPs and the resulting cumulative NPV of the benefits resulting from the addition of the NECEC Project. The dark red corresponds to the benefits associated with the 981 MW portion of the project, whereas the light red corresponds to the additional benefits from the additional [redacted] MW portion of the project.

The injection of clean energy from the NECEC Project will yield significant price impacts to ISO-NE energy prices that will benefit ratepayers, with the impacts being most pronounced in Maine.

Considering only the assumed additional energy associated with the RFP contract, Maine ratepayers will yield levelized benefits of $40 million per year (present value $454 million) resulting from LMP reductions averaging $3.38/MWh. When including energy from the full capacity of the line, the additional energy that may be imported on a market price basis will increase total benefits to Maine ratepayers $44 million per year (present value $496 million) resulting from LMP reductions averaging $3.70/MWh.

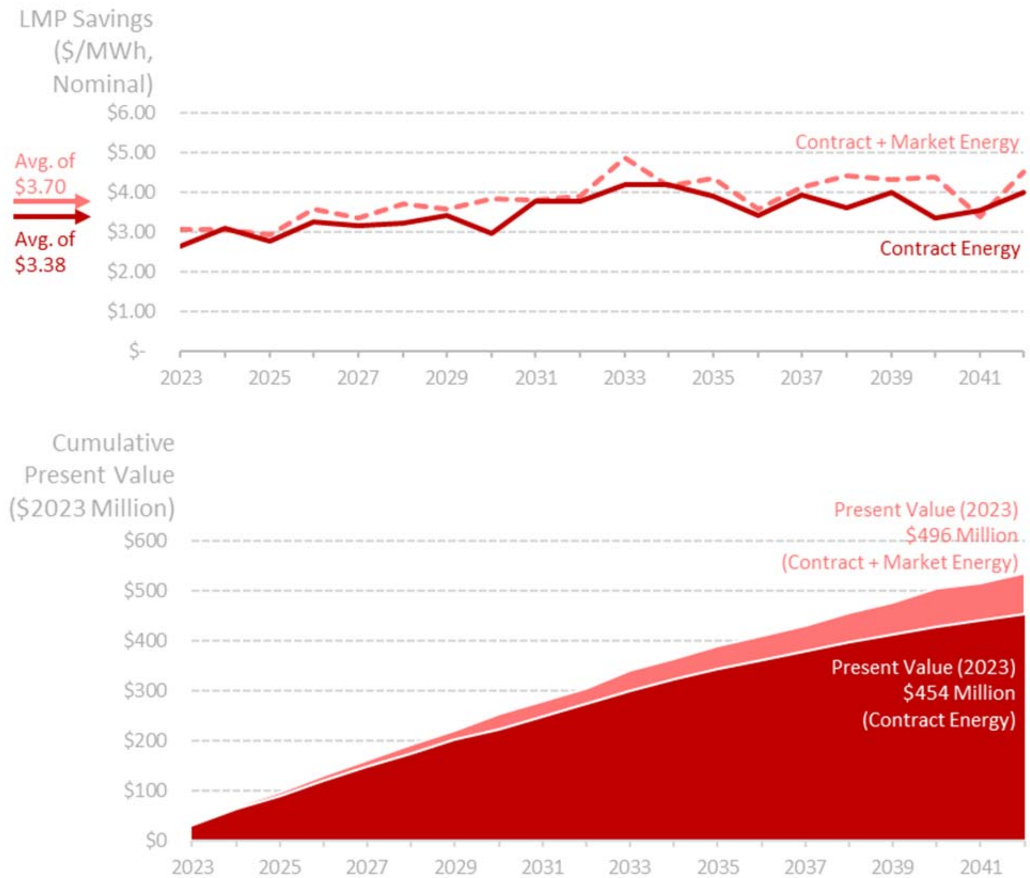

Figure 4. LMP Savings Benefit ($/MWh) and Present Value of Cumulative Benefit to ME Ratepayers ($2023 Millions)

B. Capacity Market Impacts

As a large source of clean, firm, low-cost generation, the NECEC Project Bids have the potential to provide significant benefits to the ISO-NE capacity market. The Massachusetts RFP requires that all proposed projects satisfy the Capacity Capability Interconnection Standard.[15] For capacity market purposes, either of the NECEC Project Bids would be considered an import resource associated with an elective transmission upgrade[16] and, given that the Bids are being offered in accordance with the appropriate interconnection standards, would be eligible to offer incremental capacity into the ISO-NE FCM. The offer price for the capacity would be subject to review and potential mitigation by the ISO-NE Internal Market Monitor (IMM).[17]

We analyzed the potential impact of the NECEC Project Bids on the ISO-NE capacity market and the resulting benefits to Maine ratepayers. Each year, ISO-NE procures capacity through the Forward Capacity Auction (FCA) and allocates the cost of that capacity – determined primarily by clearing price and amount procured – based on the load-ratio share of the system's coincident peak.[18]

For the purposes of this analysis, we assumed that the NECEC Project Bids result in REDACTED MW of incremental qualified capacity starting in FCA14, with a capacity delivery period of June 2023 – May 2024. The NECEC Project will be subject to several tests in order to qualify to participate in the market, and then must offer its capacity at a competitive price in order to clear the market. To assess the potential impact of the capacity for this analysis, we assumed that the capacity qualifies and offers at a price that clears the market in every year. We used our New England FCM model to determine the changes in the types and timing of capacity supply (imports, resource retirements, new generation additions) and changes in market clearing prices due to the addition of REDACTED MW from the NECEC Project Bids.

Our New England FCM model is a standalone tool used to simulate future FCAs. The model incorporates several generator-specific cost and revenue components, including energy revenue data from the AURORA production cost modeling, to compile resource going-forward costs (also known as "delist bids"). The model incorporates these delist bids along with forecasts of Cost of New Entry (CONE) to clear or retire resources using the ISO-NE demand curve.[19]

Our analysis found that the addition of the new low-cost capacity initially displaces other price-sensitive import resources. The impact of the additional capacity supply also advances the retirement of a small amount of capacity in the region that was dependent on capacity revenue for viability.

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15 The Capacity Capability Interconnection Standard (CCIS) ensures that a new resource can interconnect into the New England transmission system and fully deliver its capacity without compromising the reliability, stability, and operability of the larger grid.

16 An elective transmission upgrade (ETU) is generally comprised of a transmission element with interconnection points within the New England Control Area tied to one or more generation resources.

17 Appendix C discusses these interconnection, qualification, and offer pricing issues in more detail.

18 The ISO-NE CELT report forecasts Maine's portion of system coincident peak to average 7.5%.

19 Appendix C provides additional detail on the FCM model.

The addition of either NECEC Project Bid yields benefits due to reduced capacity clearing prices for the first 8 years of the project. After this point, the market approaches equilibrium, with the cost of new incremental capacity (also known as the Net Cost of New Entry, or "Net CONE") setting the market clearing prices. Once the market reaches this point and new supply is clearing the market, the NECEC Project Bids no longer yield benefits over a market future without the NECEC Project Bids.

Based on the results of this analysis, we calculated the FCM-related benefits of the NECEC Project Bids on Maine ratepayers by comparing the Maine allocations of ISO-NE capacity costs between the two cases (with and without NECEC Project Bids).

During the first 8 years of the project, assuming it clears in each year, the NECEC Project Bids produce an average of $50 million per year in benefits to Maine ratepayers, and a total NPV of $312 million (2023$) over the study period.

Since the FCA clearing price determines capacity costs across the ISO-NE region, there are even broader benefits to New England as a whole. The NPV of benefits to the region total $4.17 billion over 8 years.

This analysis is subject to key uncertainties including inherent market uncertainty. While we have assumed that the NECEC Project Bids will clear REDACTED [redacted] MW beginning in 2023, this assumption depends on factors such as the ISO-NE IMM review of bid prices, the amount of qualified capacity that can be sold in the market, and the price and amount that clears in the market. Furthermore, potential ISO-NE Market Rule changes in the qualification and capacity auction clearing process – such as the proposed two-tiered auction – can change how an import resource associated with an ETU will participate in the market and its likelihood of obtaining a capacity supply obligation. Nevertheless, our analysis indicates that under plausible assumptions, the benefits of reduced capacity costs of the NECEC Project Bids to Maine and New England ratepayers could be substantial.

IV. GHG REDUCTIONS

As discussed in Section I.D., Maine has established goals for long term GHG reductions. The NECEC Project will contribute to the state's efforts to achieve those goals through the guaranteed delivery of emission-free energy.

Maine is part the New England Control Area, an integrated system where generation from units in Maine may be needed to serve load outside of Maine. Likewise, Maine electricity demand can be served by units located outside Maine.

Therefore, to determine Maine's share of the New England emissions reductions caused by the NECEC Project, we first derived New England-wide emissions reductions and then allocated to Maine based on the ratio of Maine load to total New England load. Compared to a case without the NECEC Project, New England-wide CO_2 emissions are reduced by approximately 3.1 million metric tons of carbon emissions annually. Since Maine represents just over 8.5% of New England load, the NECEC Project would lead to approximately 264,000 fewer metric tons of carbon emissions annually from electric load in Maine as compared to a status quo case. This is roughly a 10% reduction in carbon emissions related to Maine electric load.

V. ADDITIONAL PRICE BENEFITS FROM A REGIONAL CLEAN ENERGY HEDGE

As the ISO-NE market has become more reliant on natural gas as the primary marginal fuel, Maine customers have been impacted by volatile fuel prices in recent years. This impact has been felt both on a short-term basis (daily or weekly price spikes typically experienced in winter months) and a medium-term basis (months or years with higher prices). There have been several state and regional efforts to increase supply of natural gas to the region, but many have so far been delayed. The NECEC Project's delivery of firm, unconstrainted, clean energy into New England reduces reliance on energy from natural gas generators, allowing greater market flexibility under high gas prices that can drastically impact energy market prices, such as have occurred in the recent past in New England. While a firm price contract serves as a hedge for Massachusetts load, the NECEC Project will also serve as a hedge for the rest of New England load through the delivery of firm, all hours inframarginal clean energy. This delivery will help protect Maine customers from multiple high gas price scenarios, as described below.

A. Sustained High Gas Price Scenario

To calculate the potential for the NECEC Project to hedge against high gas prices, we first analyzed a scenario with systematic high natural gas prices persisting throughout the contract period. For this scenario, we utilized the highest gas price scenario included in U.S. EIA's 2017 AEO.[20] The figure below compares the Reference and High prices for gas delivered to New England.

[20] The AEO's highest gas price scenario is termed "Low Oil and Gas Resource and Technology", and represents a future in which oil and gas supply is low, and technological advancement in recovery techniques is delayed, causing high prices.

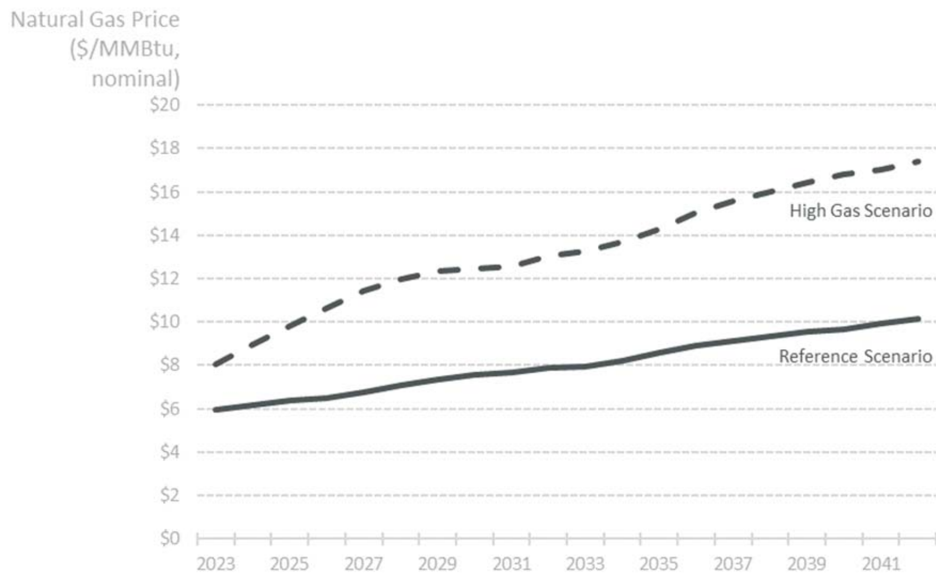

Figure 5. Algonquin Citygates, Reference and High Gas Scenarios

In a high gas future, the value of low-cost firm energy increases. We calculated the incremental LMP-related savings to Maine ratepayers in this kind of future; the additional savings totaled $83 million (2023$ NPV) over the study period. These additional savings illustrate the benefit that Maine ratepayers receive even without being the purchaser of the clean energy low-cost clean energy.

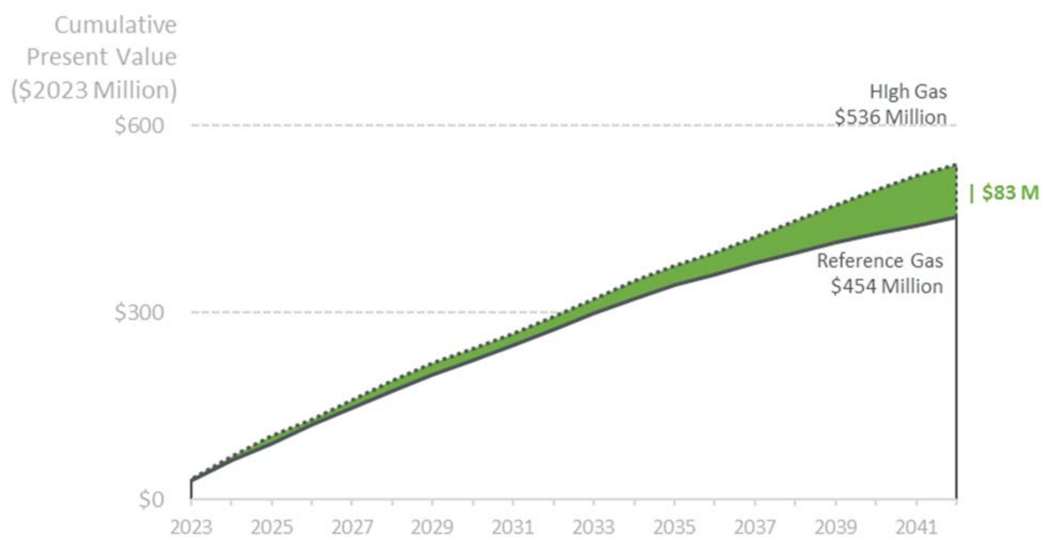

Figure 6. Present Value of Cumulative Benefit to ME Ratepayers, Reference and High Gas Price Scenarios ($2023 Millions)

B. Temporary High Gas Price Scenario (i.e., Polar Vortex)

The second scenario analyzed relates to recent winter price spikes experienced in the region. The ISO-NE market has been subject to severe winter electricity price spikes in several recent years. In many cases these price spikes have been temporary and episodic, but have exposed Maine ratepayers to extreme volatility and high wholesale energy prices.

This condition arises most frequently during cold winter periods when the natural gas pipeline capacity is being used by the natural gas Local Distribution Companies (LDCs) for space heating purposes, resulting in a lack of available supply for natural gas generators in the region. With insufficient supply, natural gas prices spike and less-efficient and normally higher-priced oil units are dispatched to meet demand. This ultimately results in an escalation in electricity market clearing prices.

This market condition is distinct from the persistent high natural gas price scenario described in the context of firmness benefits in Section V.A. above. Long-term high natural gas prices are the result of broader market conditions impacting supply and demand. These short-term spikes, by contrast, are the result of acute system conditions, but can have severe customer impacts in only a small number of days or hours.

We evaluated the benefits that the NECEC Project Bids would provide under these high winter price spike conditions. For the Reference Case analysis, the monthly natural gas price shape modeled reflects average conditions, with no extreme price conditions. For the analysis of the impact of NECEC Project Bids on winter electricity price spikes, we modeled the 2024-2025 winter period assuming that natural gas prices mimicked the daily price shape for the 2013-2014 winter period, when “polar vortex” conditions caused extreme natural gas and electricity prices in New England.

The figure below compares the winter natural gas basis (difference between the Henry Hub and Algonquin Citygates prices) used in the Reference Case analysis with the daily basis used to replicate the conditions of the 2013-2014 winter. No other changes were made to the model assumptions.

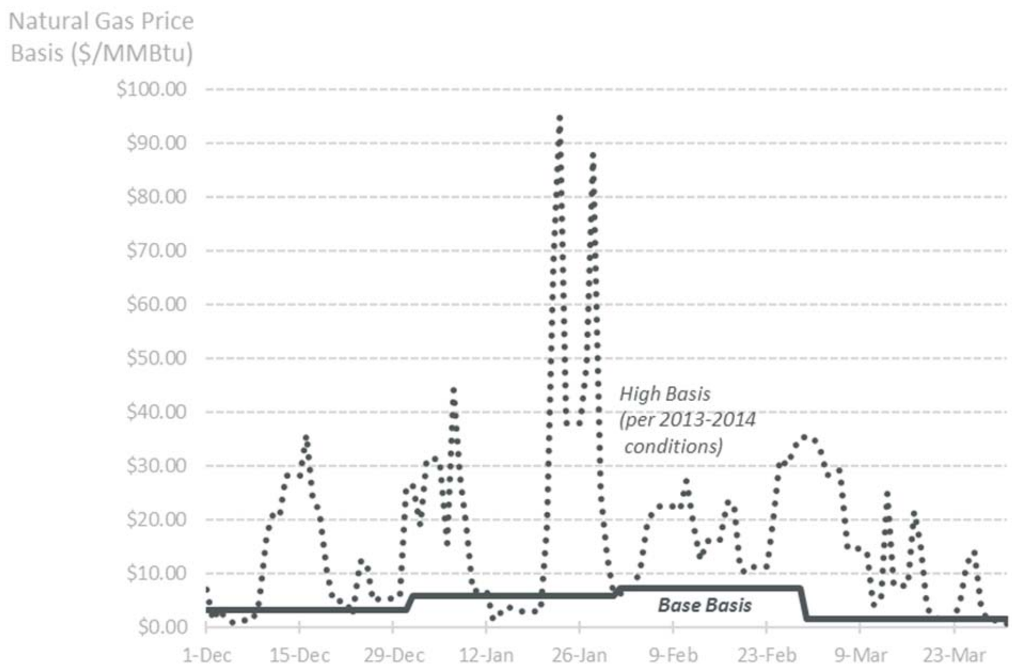

Figure 7. Natural Gas Price Basis from Henry Hub to Algonquin Citygates ($/MMBtu)

We evaluated the NECEC Project under both conditions for the 2024-2025 winter to assess the value of the project under these extreme conditions. The results show that in the high winter price spike scenario, the NECEC Project Bids produce LMP-related savings to Maine ratepayers of $51 million (nominal) for the period from December through March, as compared to $9 million in the Reference Case for the same period. The figure below depicts the Maine LMPs for the modeled futures, each with and without the NECEC Project.

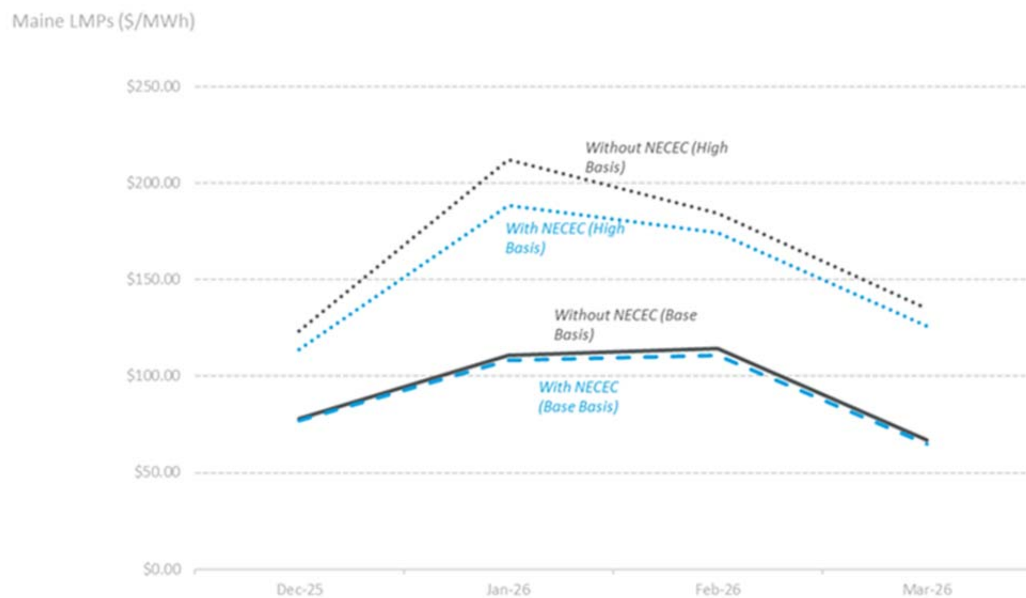

Figure 8. Maine Locational Marginal Prices under Base and High Basis Assumptions ($/MWh)

Because it is unlikely that the conditions of the winter of 2013-14 will be precisely replicated, these results should be viewed as directional and indicative of the possible scale of savings. These indicative results demonstrate, however, the value of the NECEC Project Bids as a hedge against extreme gas price conditions. When gas prices spike and LMPs escalate, the NECEC Project's value in reducing LMPs also increases. Spread across all load in Maine, these LMP reductions can generate large benefits over a short period of time.

The beneficial impact on ratepayers of the hedge provided by the NECEC Project Bids could be very substantial for Maine load in the short run and, as noted above, reduce the long-term costs for ratepayers by reducing the impact of price volatility.

C. Hedging Value Against Thermal Generation Retirements

The NECEC Project provides additional hedging value as a large source of clean, firm capacity that is not subject to volatile fuel prices, and therefore can mitigate the impact of potential future thermal generation retirements.

Maine and New England customers are exposed to ongoing electricity supply cost risk due to the potential for conventional thermal and nuclear resources in the region to retire in coming years. The regional supply of dispatchable thermal resources predominantly consist of natural gas resources. There are just a small number of coal units remaining online in New England and a larger number of oil-fired generators, though many of these resources are older.

Several of the non-gas generators are potentially at risk of retirement in the near future due to increasing operating and maintenance costs and a potential decline in energy and capacity revenues. As these units retire, the further dependence of the ISO-NE market on natural gas generators exposes Maine and New England customers to increased risk of the high gas price scenarios discussed above.

The NECEC Project serves as a hedge against the market effects of these potential resource retirements by adding a large source of firm capacity while enhancing the fuel diversity of the ISO-NE supply mix.

Additionally, retirements put upward pressure on the ISO-NE FCM. The addition of [redacted] MW of low-cost firm power that, by the requirements of the Massachusetts RFP, must pass the necessary tests for deliverability into the capacity market will act a hedge against increases in capacity costs to ratepayers.

VI. IMPACT ON ANCILLARY SERVICES

One of the issues frequently discussed in relation to renewable energy is the impact on ancillary services. Intermittent resources can, depending on circumstances, place extra burden on a system's ability to ramp up or down, leading to the need for more fast start resources to provide regulation and operating reserves. The NECEC Project avoids this potential issue by providing firm power to the grid based on an agreed upon schedule that will be part of the contracts with the Massachusetts electric Distribution Companies. Backed by Hydro-Québec's significant hydroelectric facilities, the resources available to provide the clean energy under the NECEC contract will be available in all hours.

As ancillary services are centrally coordinated and procured by ISO-NE, system-wide costs for these services are allocated to the system on a load-ratio share basis. As a large source of firm energy with a predictable schedule, the NECEC Project will likely reduce the cost of providing ancillary services to the grid. Maine ratepayers will therefore benefit proportionally from the reduction in ISO-NE ancillary services costs.

We have not quantified these benefits for this report, but have described the impacts below.

A. Operating Reserves

Units that provide operating reserves in New England are generally unavailable to provide energy, as they are required to bid at a level well above their cost, therefore ensuring they only dispatch rarely. This means that the operating reserve and energy markets compete for resources. Providing a large block of firm, low-cost power will move higher-cost units further up the supply stack, leading some to seek revenue by providing operating reserves instead of energy. The provision of firm energy will therefore exert downward pressure on the various operating reserve markets in New England by increasing supply.

Highly reliable power such as is provided by the NECEC Project, will also assist ISO-NE operations with non-performance issues when the system is under stress. ISO-NE has experienced high system stress instances in the past, where resources fail to respond to instructions due to various reasons such as gas limitations, weather induced derates, or other issues. By having roughly 1,000 MW of highly reliable power, the impact of these non-performing assets will be reduced because ISO-NE may be able to rely on them less.

B. Ramping

In addition to pushing units up the supply stack and out of the energy market, the NECEC Project will also allow some units to operate at levels that will allow for more ramping capability in New England. This is a significant benefit, as more ramping capability in any given hour means that it is easier to absorb more intermittent resources. So not only will the NECEC Project provide a large block of firm clean energy, but it will assist the system in absorbing even more clean energy over time.

VII. OTHER BENEFITS

In addition to the benefits discussed in Sections III. through VI. above, we studied the following additional benefits and issues that the Commission may wish to consider as it evaluates the NECEC Project:

- Regional and Maine reductions in electric sector natural gas consumption; and,
- Energy congestion mitigation considerations.

A. Energy Sector Reductions in Consumption of Natural Gas

In addition to the impacts on energy, capacity, and REC prices, plus the reductions in Maine and New England CO_2 emissions, the NECEC Project Bids will help reduce the electric sector demand for natural gas. This reduction in natural gas demand will provide downward pressure on the spot market for natural gas. Because New England marginal wholesale electric costs are based almost exclusively on natural gas, this will also provide an additional benefit in the form of further lowering LMPs. In addition, lower regional natural gas prices will benefit all natural gas consumers, including those that use natural gas for heating or other residential, commercial, or industrial purposes.

While we do not attempt to quantify these additional benefits in this report, we did quantify the reduction in natural gas burn in Maine and in the region resulting from the addition of the NECEC Project. The NECEC Project induced an average annual reduction of 54.2 million MMBtu of natural gas burn in the ISO-NE region, and an average of nearly 8 million MMBtu annually in Maine.

Figure 9 provides the monthly natural gas burn in ISO-NE in 2023 to illustrate the shape of the impact of the NECEC Project.

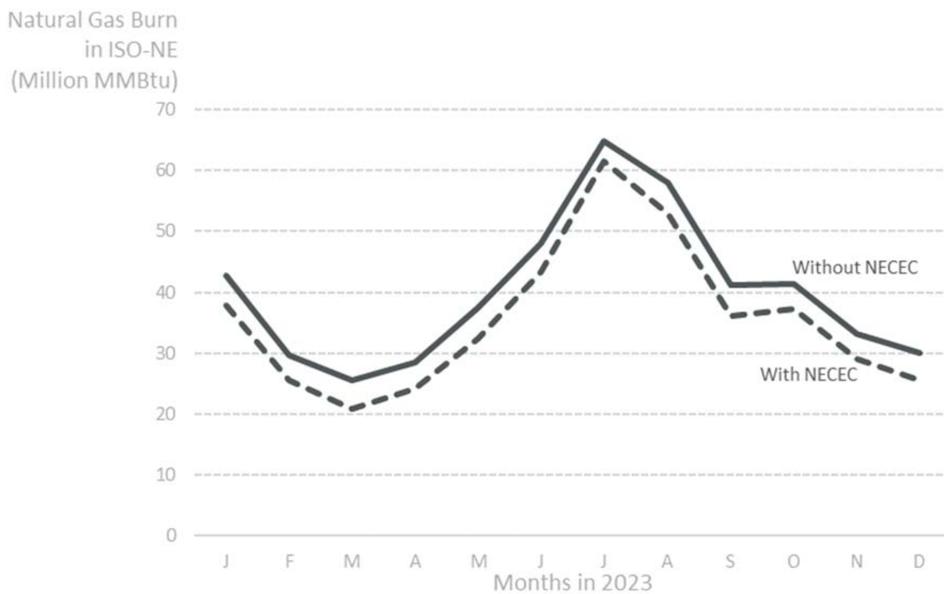

Figure 9. ISO-NE Natural Gas Consumption, 2023 (Million MMBtu)

As can be seen in Figure 10 below, the impact, on a percentage basis, is greatest in the winter. This is beneficial, as the supply of natural gas to electric generators is tightest in the winter months, making a larger reduction in those months desirable.

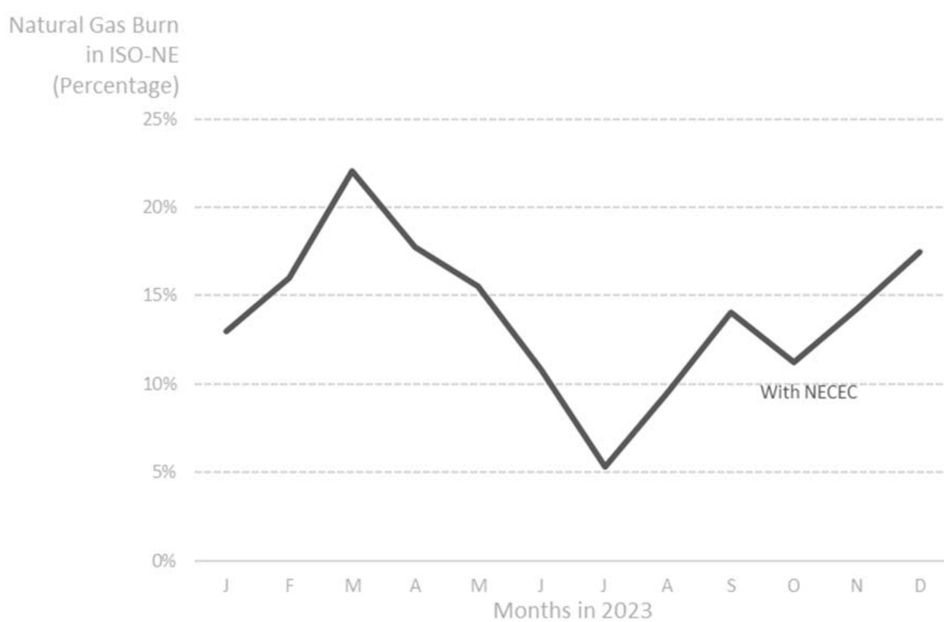

Figure 10. Monthly Natural Gas Consumption by ISO-NE Generators, Percent Reduction With NECEC Project, 2023

B. Energy Congestion

We performed two analyses designed to review the impact of the NECEC Project on regional and Maine-specific congestion. First, we reviewed the annual results for the 20-year Reference Case at two key interfaces:

- Surowiec South Interface; and
- Maine-New Hampshire Interface.

The results of the long-term analysis shows that the NECEC Project Bids do not create material congestion at Maine interfaces, with results showing: (1) uncongested deliveries on the Surowiec South interface more than 99.9% of all hours; and (2) uncongested deliveries on the Maine-New Hampshire interface more than 99.2% of all hours.

In addition to the zonal analysis, we reviewed the hourly data for key interfaces that could represent bottlenecks for new renewable energy deliveries from western Maine to southern New England. The interfaces reviewed in this detailed manner included:

- Surowiec South Interface;
- Maine-New Hampshire Interface;
- NNE-Scobie+394 Interface; and
- New England North-South Interface.

These interfaces were evaluated using a nodal representation of the New England grid, modeling an "all lines in" condition for one year (2025). In all cases, following the construction of the NECEC Project, the key interfaces were unconstrained a minimum of 99% of the hours in the year.[21] To provide a conservative estimate of potential congestion, the DC line was assumed to be running at its full 1,200 MW capability all hours of the year for this test. No congestion resulted at Surowiec South. Figure 11 through Figure 14**Error! Reference source not found.** below depict duration curves of the hourly flow over each of the four tested interfaces for 2025, with and without the NECEC Project in place.

[21] See Technical Appendix A, Section V for discussion of these calculations.

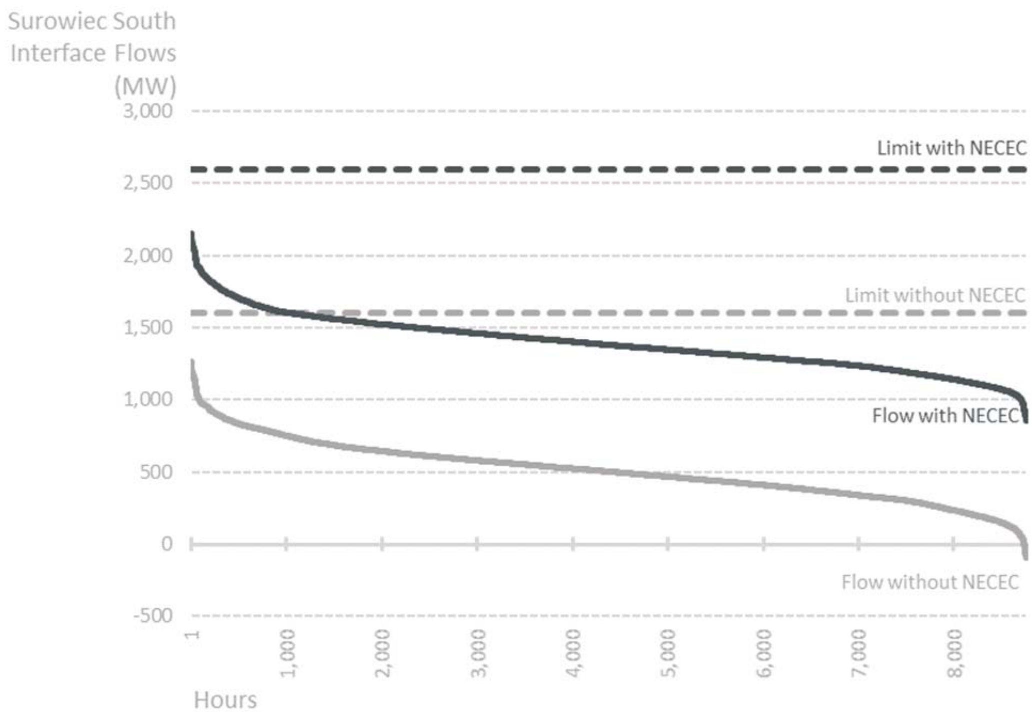

Figure 11. Surowiec South Interface Hourly Flow Duration Curve (2025)

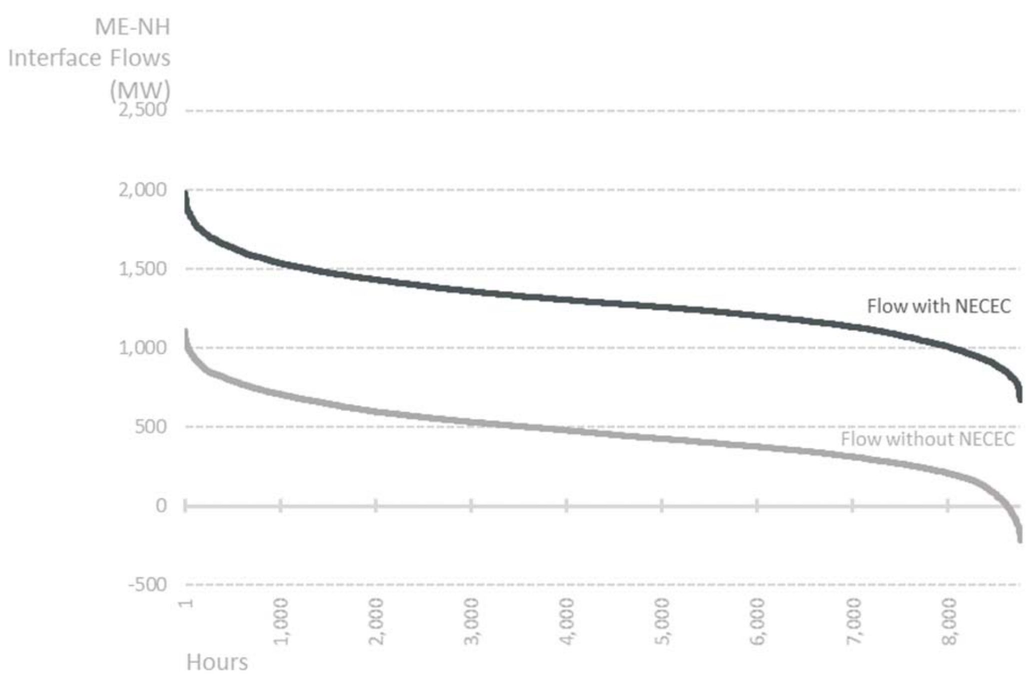

Figure 12. Maine-New Hampshire Interface Hourly Flow Duration Curve (2025)

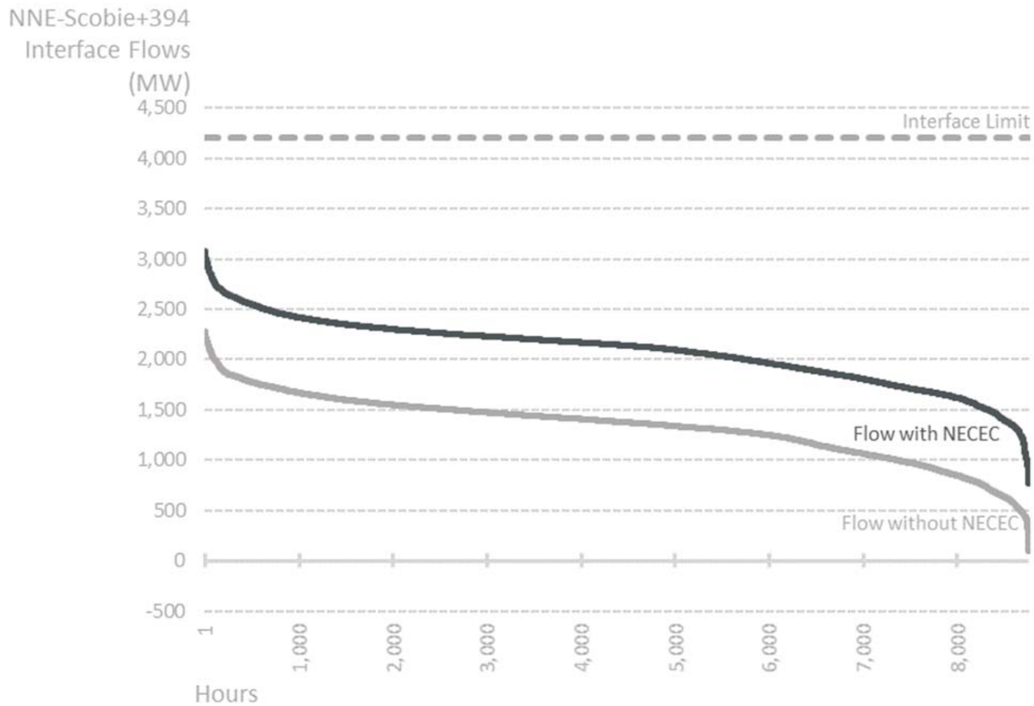

Figure 13. NNE-Scobie+394 Interface Hourly Flow Duration Curve (2025)

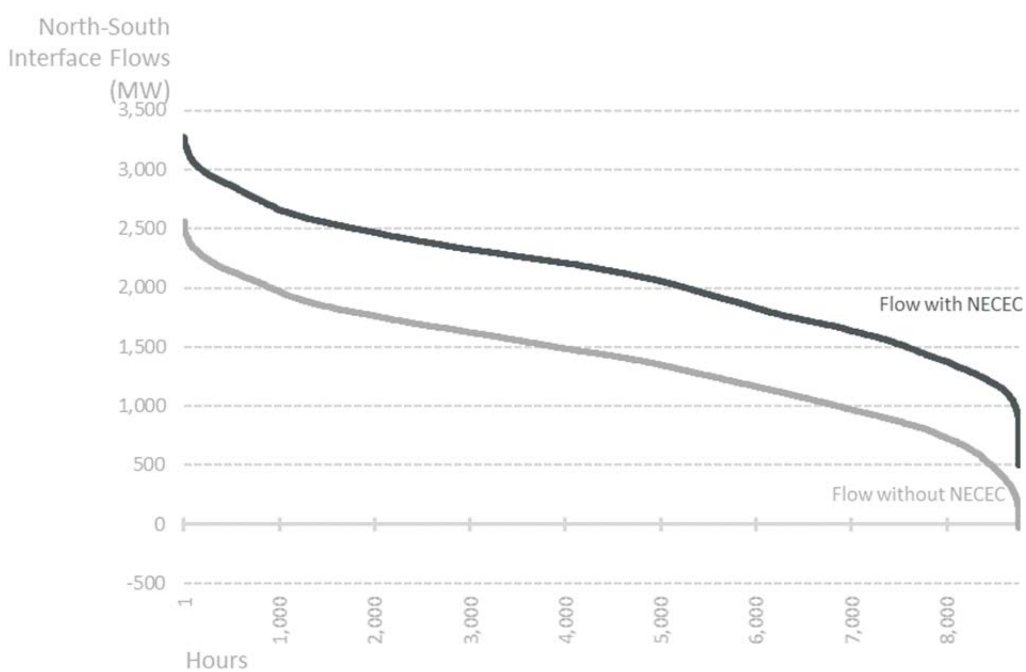

Figure 14. North-South Interface Hourly Flow Duration Curve (2025)

APPENDIX A: ENERGY MARKET MODELING DETAILS AND METHODOLOGY

SEPTEMBER 27, 2017

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I. INTRODUCTION

Daymark Energy Advisors performed energy market analysis in support of the New England Clean Energy Connect (NECEC) Project Bids. The analysis utilizes production cost modeling to examine the benefits of the proposed transmission upgrades and incremental hydroelectric and wind generation capacity.

The two NECEC Project Bids (collectively referred to as the Bids, individually as Bid 1 and Bid 2) are being offered as separate and exclusive offers of Clean Energy Generation, each to be delivered via the NECEC Transmission Project. Each Bid includes a combination of Clean Energy Generation and the NECEC Transmission Project.

In Bid 1, Hydro Renewable Energy LLC (HRE)[1] is sponsoring firm service hydroelectric generation. Bid 1 includes [redacted] megawatts (MW) of hydroelectric energy, offered at a [redacted] capacity factor, providing approximately 8,600 gigawatt hours (GWh) of firm service clean energy being delivered to the Commonwealth's ratepayers at a fixed price for energy and transmission.

In Bid 2, HRE is joined by a joint venture of Gaz Metro Limited Partnership and Boralex Inc. (collectively, the "NECEC Wind Developer") to offer a combined bid of wind energy and renewable energy credits (RECs) and firm service hydroelectric generation. Bid 2 includes [redacted] MW of wind energy backed by firm service hydroelectricity, collectively offered at a [redacted] capacity factor by the NECEC Wind Developer and [redacted] MW of hydroelectric energy, offered at a [redacted] capacity factor by HRE. The combination of these two elements of Bid 2 provide approximately 8,600 GWh of firm clean energy plus the delivery of approximately [redacted] million Massachusetts Class 1 renewable energy credits (RECs).

Central Maine Power (CMP or the Transmission Sponsor) joins each bid offering the NECEC Transmission Project to deliver the Clean Energy Generation[2]. The NECEC Transmission Project provides for the reliable delivery of up to 1,200 MW of Clean Energy per hour into the New England grid. The NECEC Project Proponents include the costs for the [redacted] MW of transmission capacity from the NECEC Transmission Project needed to deliver the Clean Energy Generation proposed in Bids 1 and 2. HRE has agreed to be financially responsible for the remaining [redacted] MW of transmission capacity on the line.

Daymark's NECEC Project Benefits report (the "Daymark Report") provides a discussion of the results of our analysis. This appendix to the Daymark Report provides additional detail on the evaluation and describes the energy market modeling methodology and analysis which informed our conclusions. The analysis described in this appendix yielded the following results and conclusions in the Daymark Report:

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1 HRE is an affiliate of Hydro Québec.

2 CMP proposes to develop, construct and own the NECEC transmission facilities on the U.S. side of the border. The transmission facilities located on the Canadian side of the border will be developed, constructed and owned by Hydro Québec TransEnergie, Inc. (HQT), an affiliate of Hydro Québec and HRE, in accordance with HQT's Open Access Transmission Tariff.

- Direct Contract Benefits – RFP Section 2.3.1.1
- Other Costs and Benefits to Retail Customers
  - LMP impact – RFP Section 2.3.1.2(i)
  - Production cost impact – RFP Section 2.3.1.2(i)
  - GWSA impacts – RFP Section 2.3.1.2(iii)
  - Resource firmness benefits – RFP Section 2.3.1.2(iv)
- Qualitative Benefits of Reliability – RFP Section 2.3.2(iv)
  - Contribution to reducing winter electricity price spikes
- Other Benefits and Considerations
  - LMP reductions in other states in region
  - Reduced natural gas consumption

This appendix describes the energy market analytical methodology and provides details on key assumptions.

II. ANALYTICAL FRAMEWORK

Daymark was retained, in part, to conduct an evaluation of the NECEC Project Bids using the quantitative and qualitative criteria and methodologies specified in the RFP, and using methods and assumptions that are representative of those that are likely to be used by the Soliciting Parties in evaluation of the proposals. To evaluate the impacts on the New England energy markets and fully account for the combined benefits of the NECEC Transmission Project and a combination of incremental clean energy projects proposed in conjunction with the NECEC Transmission Project, we performed production cost modeling using our in-house zonal energy model, the Daymark Energy Advisors Northeast Market Model (NMM). We have also conducted nodal modeling to assess the deliverability of the Bids.

To evaluate the benefits of the NECEC Bids, we analyzed multiple scenarios, each featuring a "Without NECEC Case" and "With NECEC Case". Each Without NECEC Case includes a set of our "status quo" assumptions (described below). Each With NECEC Case makes two changes to the associated Without NECEC Case. First, the Surowiec South interface limit is increased to 2,600 MW, attributable to the upgrades from the NECEC Transmission Project. Second, each With NECEC Case includes delivery of incremental clean energy generation via the NECEC Transmission Project, delivered into the Central Maine Zone.

By comparing the results of each pair of runs – LMPs, production cost, emissions, fuel burn, etc. – we calculate the economic benefits of the NECEC Bids.

The following sections describe the NMM and provide details on our key modeling assumptions.

A. NMM Overview

The Daymark Energy Advisors NMM uses an hourly chronologic electric energy market simulation model on the AURORAxmp® software platform ("AURORA"). The model provides a zonal representation of the electrical system of New England, New York and the neighboring regions.

The underlying technology, AURORA, is a well-established, industry-standard simulation model that uses and captures the effects of multi-area, transmission-constrained dispatch logic to simulate real market conditions. AURORA captures the dynamics and economics of electricity markets.

AURORA realistically approximates the formation of hourly energy market clearing prices on a zonal basis using all key market drivers, including fuel and emissions prices, loads, demand-side management (DSM), generation unit operating characteristics, unit additions and retirements, and transmission congestion and losses.

The NMM utilizes a comprehensive database representing the entire Eastern Interconnect (the North American interconnected power system east of the Rocky Mountains), including representations of power generation units, zonal electrical demand and transmission configurations. Daymark constructed this database from a number of established sources of information, including:

1. A comprehensive database issued by EPIS, Inc., the developer of AURORA.
2. The U.S. Department of Energy's Energy Information Administration (EIA).
3. The Independent System Operator of New England (ISO-NE).
4. The New York Independent System Operator (NYISO).
5. The New York Mercantile Exchange (NYMEX).

Daymark supplements the EPIS database with custom updates and revisions of key inputs for the New England and New York markets, as well as more limited updates to neighboring control areas.

III. SYSTEM TOPOLOGY

The NMM is a zonal model, where each defined zone represents a "bubble" of load and generation. Transmission is represented as single composite links between zones with constraints on certain combinations of links to represent interfaces. Key attributes that can be defined for each individual link are wheeling costs, transfer losses and transfer capability. The topology of ISO-NE and contiguous areas used to model the NECEC Project is shown in Figure III-1 below.

The zones modeled in Maine include:

- Southern Maine (SME): Generation and load between New Hampshire and the Surowiec South interface.
- Central Maine (CME): Generation and load bounded by the Surowiec South interface to the south and Orrington South to the northeast. The NECEC Clean Energy is delivered to this zone.
- Bangor Hydro Electric (BHE): All ISO-NE generation and load north and east of the Orrington South interface. This zone is also interconnected to the New Brunswick zone.
- Northern Maine Independent System Administrator (NMISA): Primarily the Emera territory known as the Maine Public District, this zone includes all Maine load not interconnected with ISO-NE. This zone is only connected to the New Brunswick zone.

The zonal topology remains the same in both the Without NECEC and With NECEC model runs. As noted above, the only change in the With NECEC cases is an increase in the Surowiec South transfer limit due to the upgrades associated with the NECEC Transmission Project.

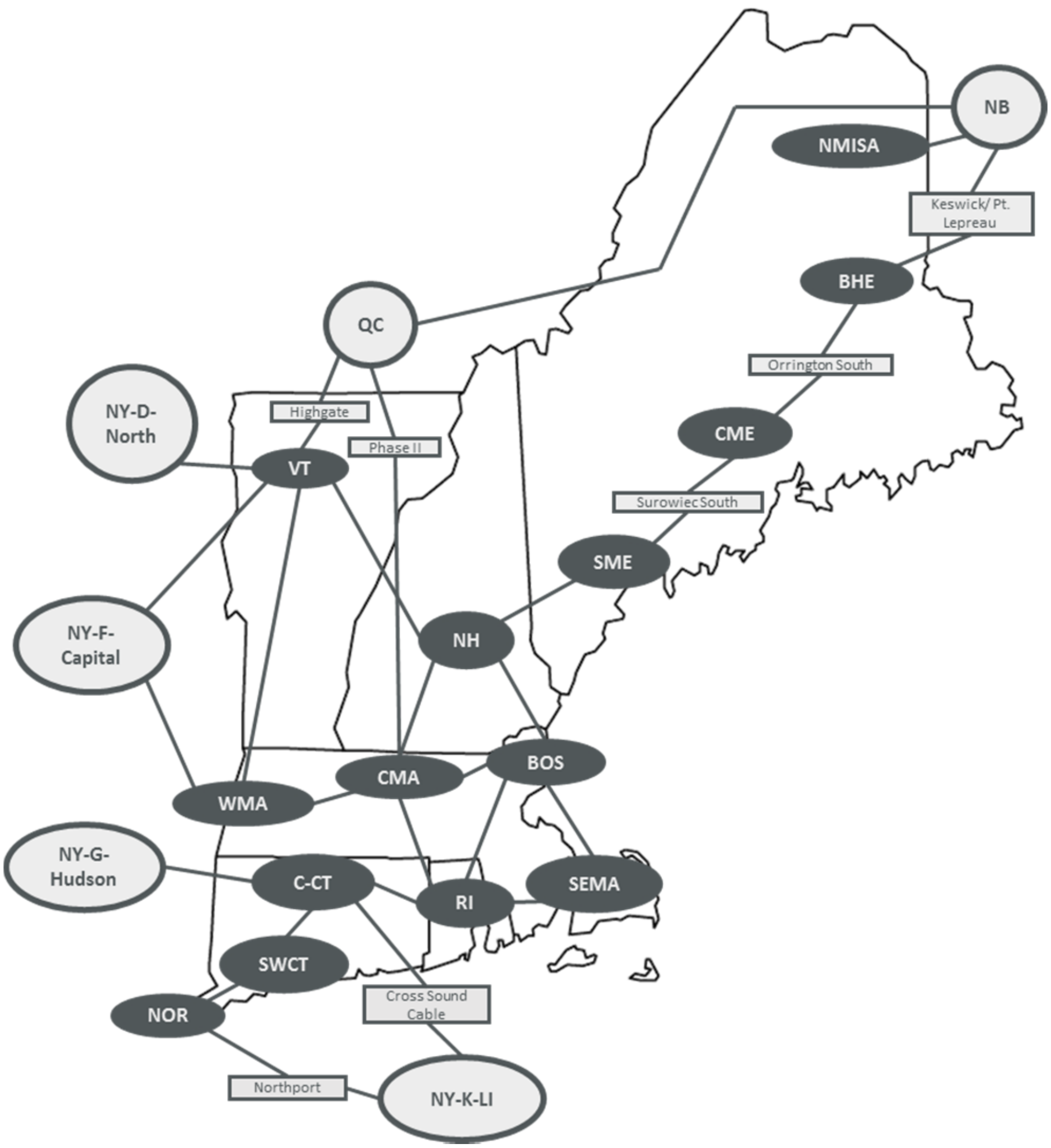

Figure III-1. NMM Model Topology: ISO-NE and regional interconnections

IV. KEY INPUTS

As discussed in the Daymark Report, Section II.C., the goal of Daymark's analysis is to conduct an evaluation of the NECEC Project using the quantitative and qualitative criteria and methodologies specified in the RFP, using methods and assumptions that are representative of those that are likely to be used by the Soliciting Parties in evaluation of the proposals.

This section provides details on the key modeling inputs and assumptions used in the NMM energy market analysis.

A. Load

Section 2.3.1.2 of the RFP notes that "[t]he reference case system topology will be based on the 2016 ISO New England Capacity, Energy, Load and Transmission (CELT) report."

Therefore, the load forecast used in the NMM for New England is based on the 2016 CELT report. Since the zones modeled in the NMM align with the RSP zones, we used the forecast values directly from the CELT report.

For the forecast years through 2025, the 2016 CELT report provided gross peak and energy load and peak and energy load net of energy efficiency (EE).[3] ISO-NE's EE forecast in the CELT report includes estimates based both on the resources cleared in the ISO-NE FCM and the load reduction projected due to state-sponsored EE programs. For extrapolation in modeled years after 2025, gross load is assumed to grow at the compound annual growth rate from 2020-2025. EE reductions are extrapolated such that EE's percent of gross load, both peak and energy, in 2025 remains constant through the rest of the study period. These extrapolations are done separately for each zone in the system.

Figure IV-1 below shows the 2016 CELT forecasts of gross and net coincident peak load and Figure IV-2 shows the gross and net energy demand for the New England Control Area.

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3 ISO-NE refers to EE as "passive demand resources" (PDR).

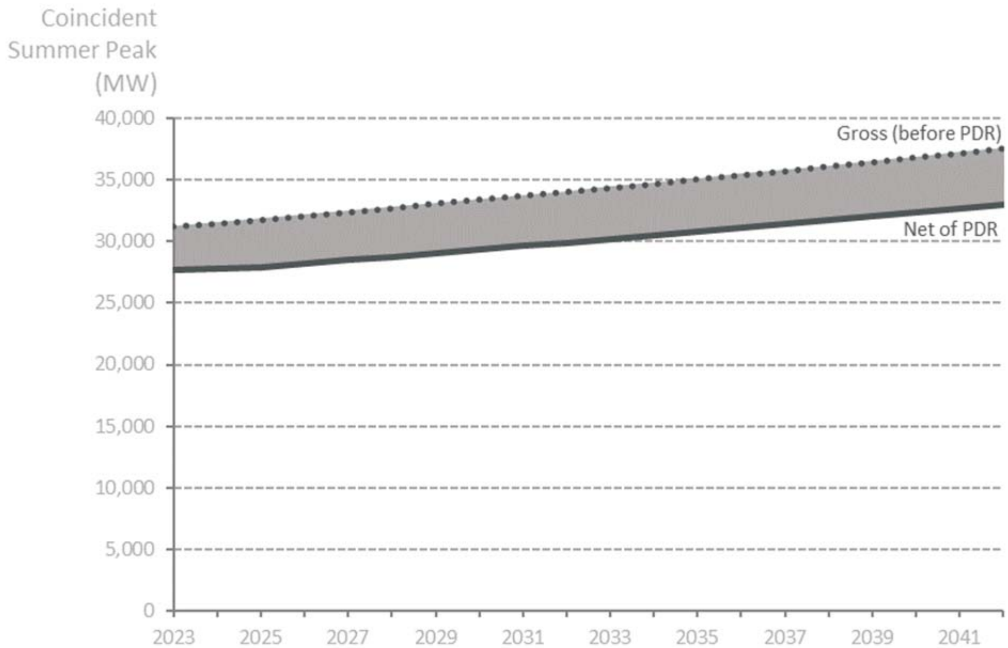

Figure IV-1: New England Coincident Peak Load, Gross and Net of Energy Efficiency

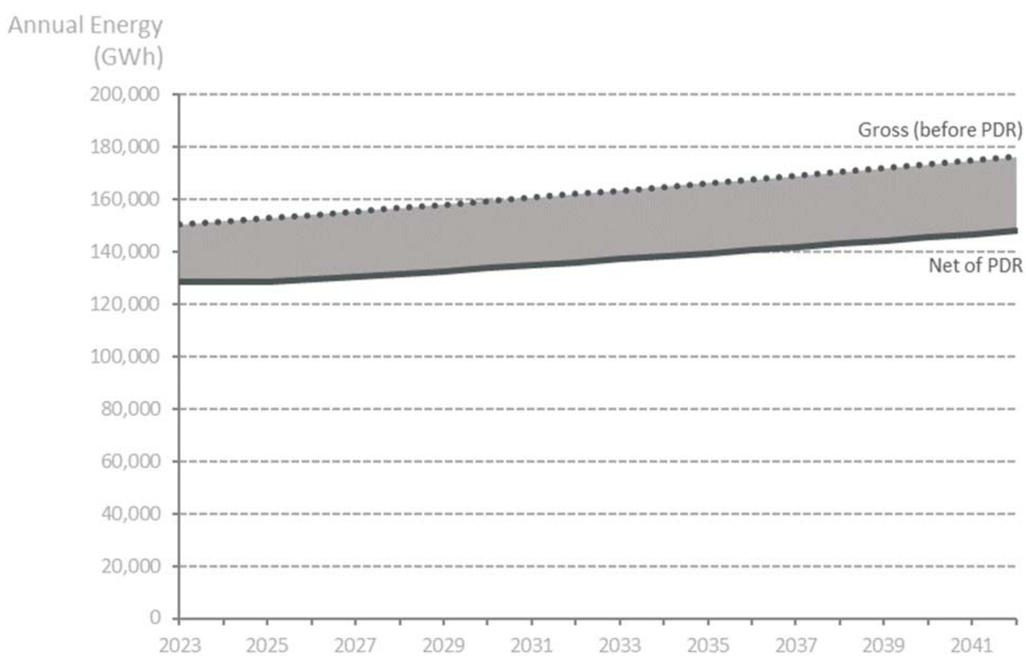

Figure IV-2: New England Energy Load, Gross and Net of Energy Efficiency

Dispatchable Demand Response (DR) units are added to New England in the NMM based upon the level of DR that has cleared in the ISO-NE Forward Capacity Market (FCM). In the market's Forward Capacity Auction (FCA) 7, the level of DR dropped precipitously from the level that had been clearing previously, and continued to decline in FCA 9 and FCA 10. Total cleared DR has declined from approximately 1,000 MW in FCA 8 to only 378 MW in FCA 10. DR capacity (in MW) for years beyond the last FCA period is assumed to remain constant at the level of the last FCA. Therefore, for the NECEC modeling, the assumption is that this lower level of 378 MW of DR persists through the end of the study period. These units are modeled as "load control" units in the NMM, and therefore when dispatched they act to reduce load instead of providing generation.

B. Fuel Prices

Fuel prices are key assumptions for the NMM, and are subject to a large amount of uncertainty. As a key component of dispatch cost, fuel prices are an important to price formation and regional market dynamics. In the NMM production cost model, each generator is assigned a fuel price based on the type of fuel, unit type, and plant location.

The following sections describe how fuel price assumptions are developed.

Natural Gas Index Prices

The ISO-NE market is currently dominated by natural gas generation and will likely remain so throughout the study period. Therefore, the natural gas price assumptions are a critical driver to our modeling and results.

For this analysis, Daymark utilized the U.S. EIA's 2017 Annual Energy Outlook (AEO) Reference Case assumptions of natural gas price indices. The AEO is a publicly available long-term forecast that is commonly used in the energy industry.

Daymark used the AEO forecast for the Henry Hub Index, as well as region-specific indices for New England, New York, and the PJM RTO (Figure IV-3 below).

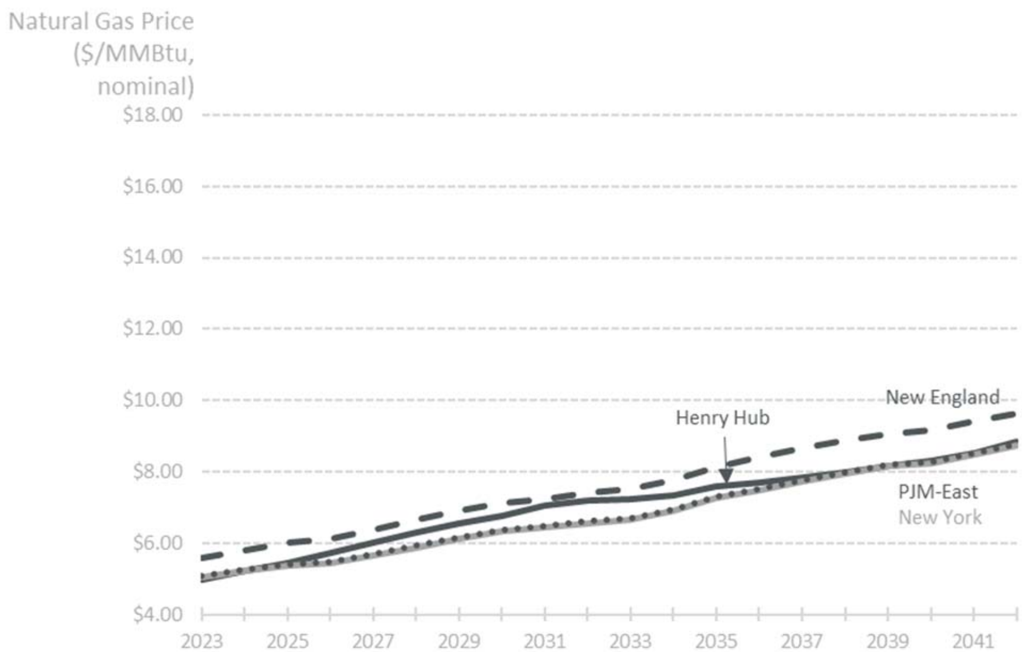

Figure IV-3. Natural Gas Price Assumptions ($/MMBtu, nominal)

In addition to the AEO Reference Case, Daymark also used AEO's high gas forecast[4] for the analysis of the value of firmness (see Section IV.D. of the Daymark Report). Figure IV-4 below depicts the price assumptions for the four indexes.

[4] The highest natural gas scenario in the 2017 AEO is the "Low Oil and Gas Resource and Technology". This scenario represents a future in which there are low physical reserves available for recovery, and the speed of technological advancement in recovery techniques is slow, resulting in low supply and high prices.

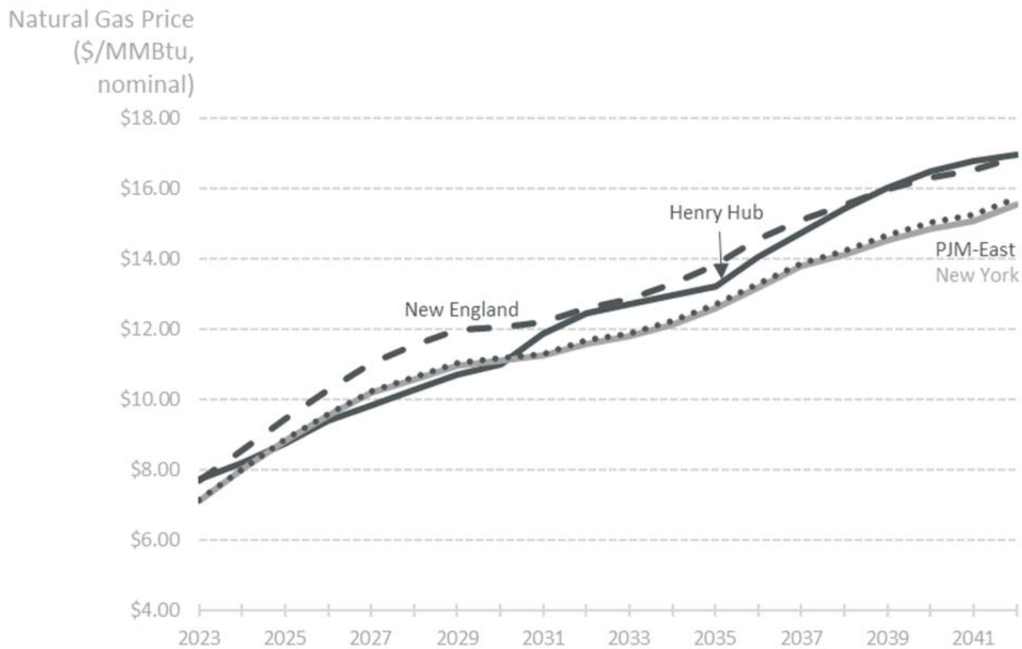

Figure IV-4. High Natural Gas Price Assumptions ($/MMBtu, nominal)

Figure IV-5 below compares the Reference Case assumption with the High Case natural gas price assumption.

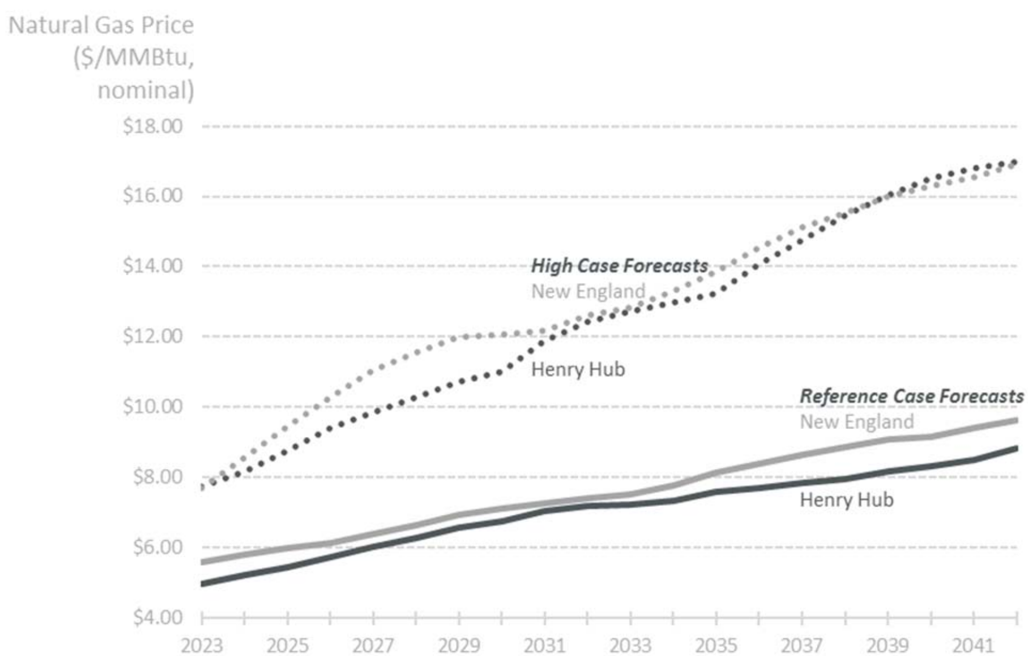

Figure IV-5. Comparison of Reference and High Natural Gas Cases

The index prices represent one component of the actual gas price used by the production cost model in each hour to determine economic dispatch of resources. For example, the price of natural gas for each New England generator is constructed according to the following basic formula for year *y*, month *m*:

$$\mathbf{DP_{y,m} = (IP_y * MS_m) + R_m + p}$$

Where:

DP	=	Delivered price to generator
IP	=	Index price, annual average
MS	=	Monthly shape factor for index price
R	=	Regional adder, if any
p	=	Peaking unit adder

The index price is sourced from the AEO as described. The derivation of each of the remaining components of the equation above is explained in the sections below.

Monthly Shape Factor for Index Prices

Annual average natural gas prices are shaped monthly to reflect seasonal trends and variation in The monthly shape vector for the index prices is based on analysis of historical trends. These values are applied to the annual index prices to yield monthly values. Figure IV-6 below displays the monthly shapes for the four primary indexes used in this analysis.

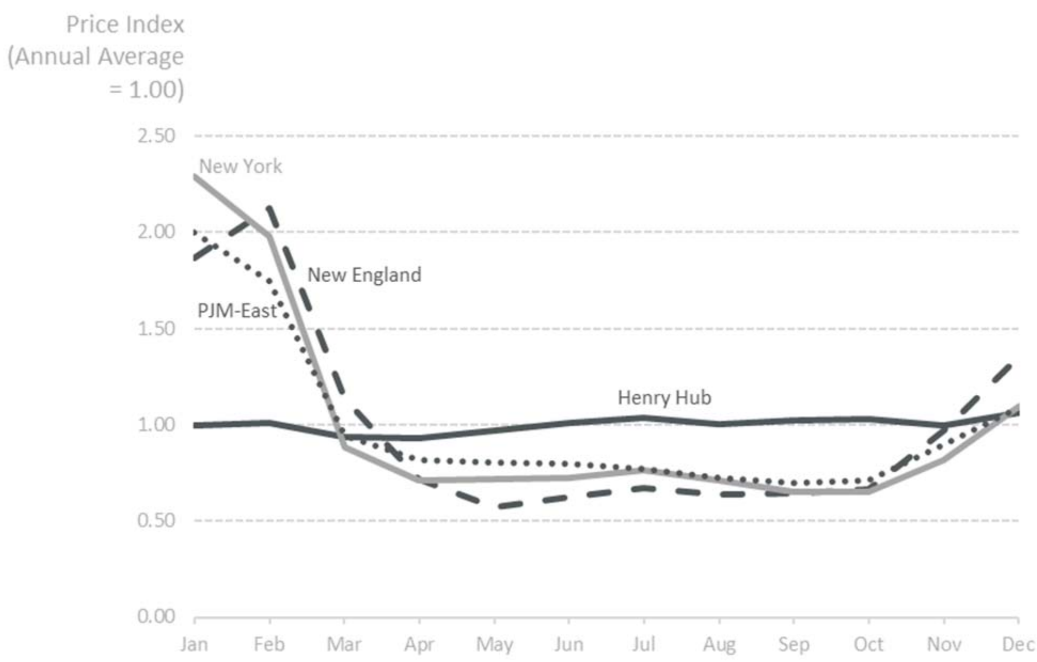

Figure IV-6. Natural Gas Index Monthly Shapes

Regional Adder

The Algonquin Citygates price provides a reasonable proxy for delivered natural gas prices for generators in southern New England. However, natural gas-fired generators in northern New England (Maine, New Hampshire, and Vermont) face additional expense due to the additional distance from gas supplies to the southwest. The NMM forecast of this additional basis is $0.59/MMBtu on an annual average basis, with seasonal range of $0.35 - $0.88/MMBtu (see Figure IV-7). The forecast is based on backhaul usage rates on the Maritimes and Northeast Pipeline and Portland Natural Gas Transmission System short term reservation rates.

Figure IV-7. Northern New England Basis Differential to Rest of New England (Algonquin Citygates)

Peaking Unit Adder

Some units are assumed to pay for fuel at prices above the monthly average price for delivered natural gas because they tend to only be dispatched on peak days when the daily gas price is likely higher. Our assumptions are summarized in the table below.

Natural Gas Delivery Class	Fuel Adder (2017$/MMBtu)	Resources in Class
Peaking	$0.89	New Haven Harbor Units 2-4 (151MW); Androscoggin Energy Center CT03 (51MW); Swanton Peaking Generation Project #10 (40MW); Algonquin Windsor Locks (38MW); Lowell Cogeneration #GEN1-2 (32MW); Capital District Energy Center STG (29MW); Waters River #1 (20MW); Pawtucket Power #1 (20MW); 15 smaller units totaling 33MW.
Super Peaking	$1.74	Devon 11-14 (161MW); Cleary Flood #9a (106MW).
Standard (Non-Peaking)	$0.00	All Remaining units.

Table IV-1. NMM Peaking Unit Fuel Price Adder Assumptions

C. Emission Prices

The NMM incorporates emission prices into the production cost and commitment/dispatch of units in the model. We incorporate prices for CO_2, NOx, and SO_2 into the NMM.

All New England states currently participate in Regional Greenhouse Gas Initiative (RGGI) program, a cap-and-trade program aimed at reducing CO_2 emissions from the power sector. Pricing carbon emissions affects New England electric energy prices by increasing the variable costs of fossil fuel-fired generators that are almost always on the margin. RGGI allowance prices have been minimal since the program began in 2009 because actual CO_2 emission levels have fallen well below the initial program caps. On February 7, 2013, the RGGI states announced their commitment to an Updated Model Rule that tightened caps significantly in 2014.

Daymark assumes that the New England states will continue to be subject to CO_2 emission prices through the study period, either through the RGGI program or a national CO_2 emissions program. Consistent with industry estimates, we assume a price for carbon emissions of $15/ton in 2022, escalating to $30/ton at the end of the study period in 2042 (values in 2016$).[5]

NOx and SO_2 emission prices are a relatively minor component of LMPs in New England because of the low emission rates of marginal generators (mostly gas units). We have assumed that NOx and SO_2 emission prices decline to $0 by 2020, the start of the study period.

[5] Source: Synapse Energy Economics, Inc. *Spring 2016 National Carbon Dioxide Price Forecast*. March 16, 2016. Available at: http://www.synapse-energy.com/sites/default/files/2016-Synapse-CO2-Price-Forecast-66-008.pdf

D. Retirements and Thermal Capacity Additions

Daymark's modeling analysis relies on assumptions of generator retirements and additions. These resource changes impact the efficiency of marginal units and can impact pricing, emissions, and net imports to the region, among other factors.

Our assumptions on retirements are based on known and forecasted retirements the ISO-NE market. The primary source of the known resource designations is the results of the ISO-NE Forward Capacity Auctions (FCA), the most recent of which (FCA11) determined capacity obligations for the 2020-2021 commitment period. In addition to these resources, further retirements and resource additions are based on results of analysis conducted with Daymark's ISO-NE FCM model.

Daymark's ISO-NE FCM model forecasts the economics of existing generators in New England, incorporating revenues from energy and capacity sales, and netting out resource costs including fuel, operation and maintenance (O&M), emission allowance costs, etc. The model determines relative economics of over 12,000 MW of generation in ISO-NE to determine the timing of resource retirements and construction of new plants.

Appendix C provides a full description of the FCM model methodology.

Figure IV-8 details the cumulative capacity additions and resource retirements assumed in the NMM.

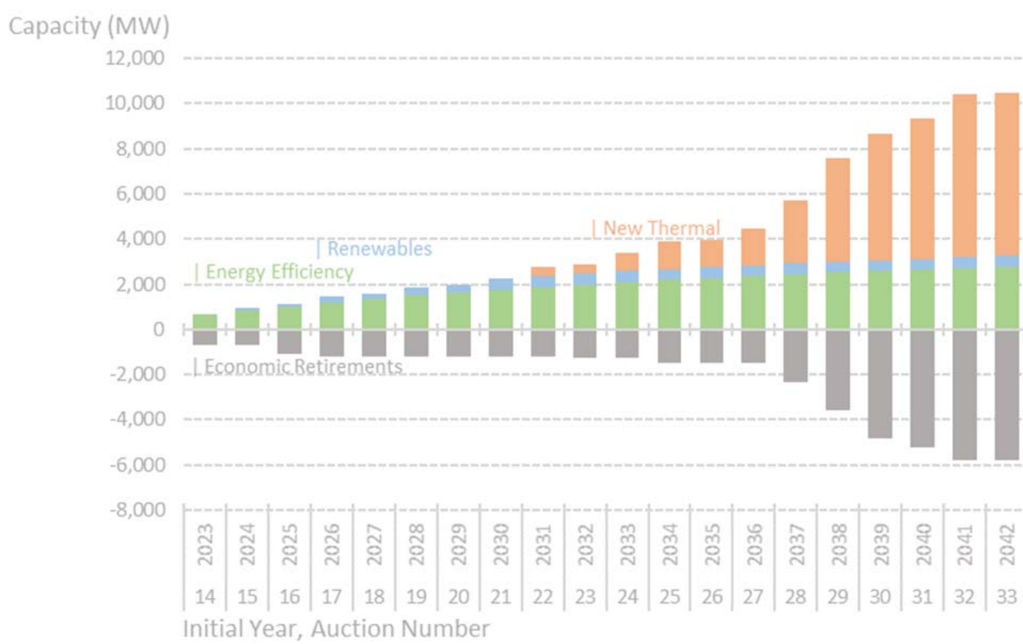

Figure IV-8. Cumulative Capacity Additions and Retirements

E. Renewable Additions

As noted above, our assumptions on renewable resources follow a “status quo” approach. Renewable projects modeled include:

- Existing and operational projects.
- Projects currently under construction.
- Projects with contracts resulting from the 2015-16 Clean Energy RFP issued by Massachusetts, Connecticut, and Rhode Island.
- New offshore wind assumed to be contracted as a results of Massachusetts Section 83C procurements.

With the exception of the offshore wind, we assume that all projects that fall under the preceding categories will be online at the start of the study period. Offshore wind is assumed to be added in 400 MW tranches every two years beginning in 2024. We also assume that all existing renewable projects will remain online through the end of the study period.

Distributed Solar Assumptions

The NMM includes a forecast of distributed, behind-the-meter solar. Our forecast is based on the ISO-NE distributed solar forecast, conducted as part of the annual load forecast and CELT report process.

The figure below summarizes our assumptions of distributed solar buildout by state.

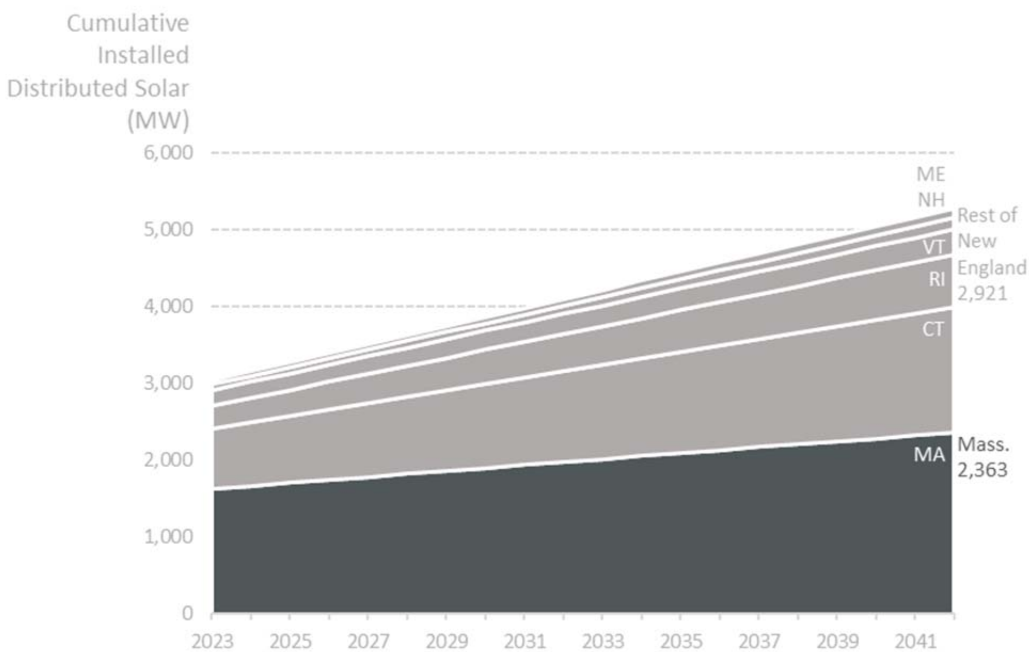

Figure IV–9. Distributed Solar Buildout (Cumulative MW)

APPENDIX B: RENEWABLE ENERGY CERTIFICATE MARKET ANALYSIS DETAILS AND METHODOLOGY

SEPTEMBER 27, 2017

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I. INTRODUCTION

Daymark Energy Advisors (Daymark) performed extensive benefits analysis in support of the New England Clean Energy Connect (NECEC) Project Bids. One component of our analysis is the mark-to-market analysis of the value of the renewable energy credits (RECs), as described in Section 2.3.1.1 of the RFP. Daymark's NECEC Project Benefits report (the "Daymark Report") provides a discussion of the results of our analysis. This appendix provides the details and analytical methodology supporting our analysis.

The two NECEC Project Bids (collectively "Bids", individually Bid 1 and Bid 2) are being offered as separate and exclusive offers of Clean Energy Generation, each to be delivered via the NECEC Transmission Project. Each Bid includes a combination of Clean Energy Generation and the NECEC Transmission Project. Bid 1 includes [redacted] megawatts (MW) of hydroelectric energy, offered at a [redacted] capacity factor, providing approximately 8,600 gigawatt hours (GWh) of energy. Bid 2 provides the same total quantity of clean energy, but instead of all hydro generation, it includes the output of [redacted] MW of new wind capacity, firmed up by the hydro to provide the same energy shape. The energy provided by the wind energy will generate approximately [redacted] million RECs that will be sold to the Distribution Companies at a fixed price.

Section II of this appendix provides an assessment and forecast of REC demand in New England. Section III provides Daymark's evaluation of existing and potential future REC supply in the region. Finally, Section IV of this appendix provides a review of historical pricing and describes Daymark's methodology for developing a REC price forecast.

II. NEW ENGLAND RENEWABLE ENERGY DEMAND FOR CLASS I RESOURCES

This section summarizes Daymark's forecast of demand for Premium Class I RECs in the New England region.

As used in this report, "Premium Class I RECs" refers to RECs eligible for compliance with Massachusetts (MA) Class I, Connecticut (CT) Class I, Rhode Island (RI) New, and New Hampshire (NH) Class I and II.[1] There are different eligibility requirements across each class and each state. Though some significant eligibility differences exist (particularly CT Class I), the markets sufficiently overlap to be thought of generally as a single market. While Maine and Vermont also have mandatory RPS standards, prices in these states are generally lower. Maine has made allowances for some existing biomass to qualify for Class I that does not qualify elsewhere, resulting in a significantly lower REC price than the other New England Class I markets. Vermont's new RPS is less stringent in its requirements than the other states as it has a low Alternative Compliance Payment (ACP) and allows large hydropower to fulfill requirements.

These premium REC classes generally contain more restrictions for eligibility and should carry higher prices due to the smaller pool of resource types that are eligible.[2] At the current time (and over the foreseeable future), Premium Class I RECs are the highest priced RECs in New England, but supply/demand dynamics for each of the REC classes ultimately determines prices. Not all classes permit participation by imported power as some classes require in-state locations (e.g., CT Class III) and have older vintage requirements (e.g., MA Class II) that reduce the applicability of the class to potential imports. Table II-1 summarizes the relevant definitions of the eligible resources for the premium classes, which are most relevant to import of certificates from outside of New England.

[1] Maine Class I was previously considered as a "premium" market but recent loosening of eligibility requirements has reduced the value of these RECs.

[2] Another factor is that the Alternative Compliance Payment, which is effectively a statutory or regulatory ceiling on prices for RECs, is generally set higher for Class I compared to other RPS classes.

RPS Class	Definition
CT Class 1[3]	Includes "energy derived from solar power, wind power, a fuel cell, methane gas from landfills, ocean thermal power, wave or tidal power, low emission advanced renewable energy conversion technologies, small (<5MW) run-of-the-river hydropower facility provided such facility has a generating capacity of not more than five megawatts, does not cause an appreciable change in the river flow, and began operation after July 1, 2003, or a sustainable biomass facility with an average emission rate of equal to or less than .075 pounds of nitrogen oxides per million BTU of heat input for the previous calendar quarter"
MA Class 1	New Renewable Generation Units are facilities that began commercial operation after 1997 and generate electricity using any of the following technologies: Solar photovoltaic, Solar thermal electric, Wind energy, Small hydropower, Landfill methane and anaerobic digester gas, Marine or hydrokinetic energy, Geothermal energy, Eligible biomass fuel
NH Class 1	Class I resources include generation facilities that began operation after January 1, 2006 and produce electricity from: wind energy; geothermal energy; hydrogen derived from biomass fuel or methane gas; ocean thermal, wave, current, or tidal energy; methane gas; or biomass Displacement of electricity by end-use customers from solar hot water heating systems, incremental new production from Class III and IV sources, and existing hydropower and biomass facilities that began operation as a new facility through capital investment also qualify as class I sources.
NH Class 2	Includes production of electricity from solar technologies, provided the source began operation after January 1, 2006.
RI New	Eligible renewable resources initially placed into commercial operation after December 31, 1997 that use direct solar radiation, wind, movement or the latent heat of the ocean, or the earth's heat; hydroelectric facilities up to 30 megawatts (MW) in capacity, Biomass facilities using eligible biomass fuels and maintaining compliance with current air permits (eligible biomass fuels may be co-fired with fossil fuels, provided that only the renewable-energy portion of production from multi-fuel facilities will be considered eligible), Fuel cells using renewable resources

Table II-1. Premium RPS Classes in New England (Definition Excerpts)

Compliance entities must purchase class-eligible RECs equivalent to a certain percentage of obligated load by a certain date each year. All four states allow some form of REC "banking", enabling compliance entities to apply a limited number of surplus RECs from one compliance year toward future obligations. The table below summarizes the minimum percentage requirements by class and by year for the 2020-2035 time period and beyond.

[3] CT Class 1 now has some allowance for large hydro to offset RPS requirements under certain conditions.

Year	CT Class 1	MA Class 1	NH Class 1	NH Class 2	RI New
2020	20.0%	15.0%	10.5%	0.3%	14.0%
2021	20.0%	16.0%	11.4%	0.3%	15.5%
2022	20.0%	17.0%	12.3%	0.3%	17.0%
2023	20.0%	18.0%	13.2%	0.3%	18.5%
2024	20.0%	19.0%	14.1%	0.3%	20.0%
2025	20.0%	20.0%	15.0%	0.3%	21.5%
2026	20.0%	21.0%	15.0%	0.3%	23.0%
2027	20.0%	22.0%	15.0%	0.3%	24.5%
2028	20.0%	23.0%	15.0%	0.3%	26.0%
2029	20.0%	24.0%	15.0%	0.3%	27.5%
2030	20.0%	25.0%	15.0%	0.3%	29.0%
2031	20.0%	26.0%	15.0%	0.3%	30.5%
2032	20.0%	27.0%	15.0%	0.3%	32.0%
2033	20.0%	28.0%	15.0%	0.3%	33.5%
2034	20.0%	29.0%	15.0%	0.3%	35.0%
2035	20.0%	30.0%+[4]	15.0%	0.3%	36.5%

Table II-2. Premium RPS Class Minimum Percentage Requirements, 2020-2035+

RPS policies in most states escalate annual until a certain target percentage is reached, with percentage requirements remaining static thereafter. By contrast, the Massachusetts RPS policy requires 15% renewable supply by 2020, and an additional 1% each following year, with no statutory end to the escalation. Figure II-1 shows the demand levels for the 2020-2035 period. Region-wide demand is expected to increase from 16 million RECs to almost 27 million Premium Class I RECs in 2035.

[4] After 2020, an additional 1% per year with no stated expiration date. Percentages include in-state solar carve-out.

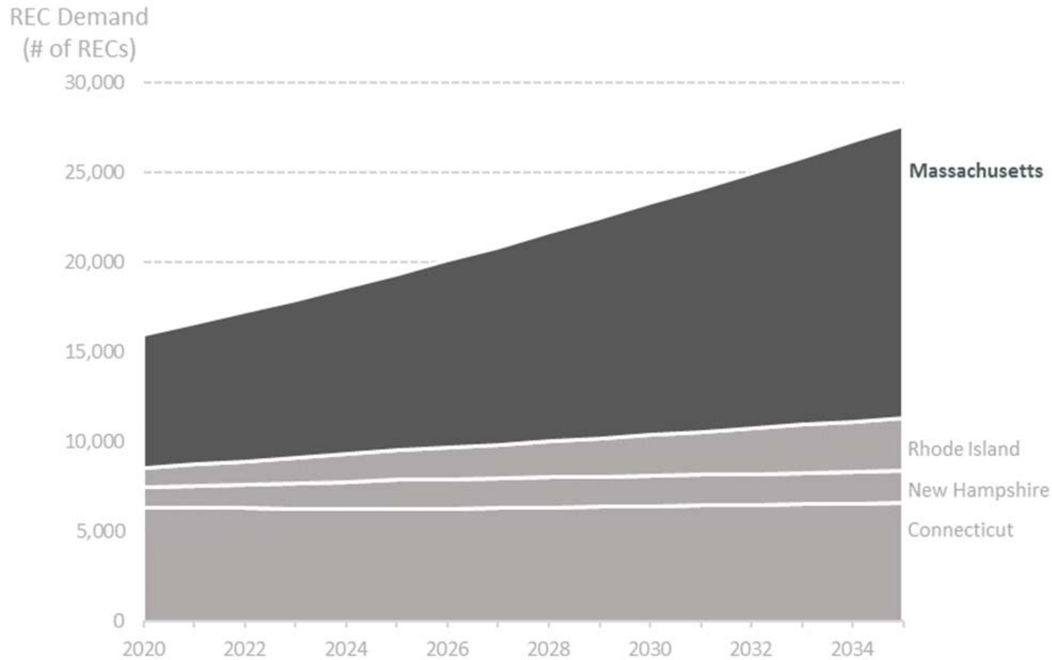

Figure II-1. Forecasted Premium Class I REC demand, 2020-2035

III. NEW ENGLAND REC SUPPLY

This section describes the existing and committed Premium Class I REC supply, the need for new supply to meet demand, and the potential impact of the NECEC project on that need.

A. Existing and Committed Premium Class I REC Supply

The New England Premium Class I REC supply includes RECs generated in New England and those generated in neighboring states or provinces that are delivered into the ISO-NE Control Area. Currently there are over 9 million Premium Class I RECs produced in New England annually and more than 2 million Premium Class I RECs imported from neighboring regions, which is approximately equal to the region's demand. Our baseline assumption is that solar installations in New England will continue over the study period at the rate predicted by ISO New England's 2016 solar forecast. We have also assumed that New York and Canadian renewable resources currently under contract to New England buyers will continue to provide Premium Class I RECs through the study period. Finally, we have also assumed that resources procured during the 2015-16 Three State Clean Energy RFP will be constructed and have included those resources in the baseline.

Figure III-1 below shows the gap between the baseline level of class I REC supply and demand in the region between 2020 and 2035. This shows a deficit of about 2,000 GWh of renewable energy in 2020 growing to about 9,000 GWh of renewable energy in 2035.

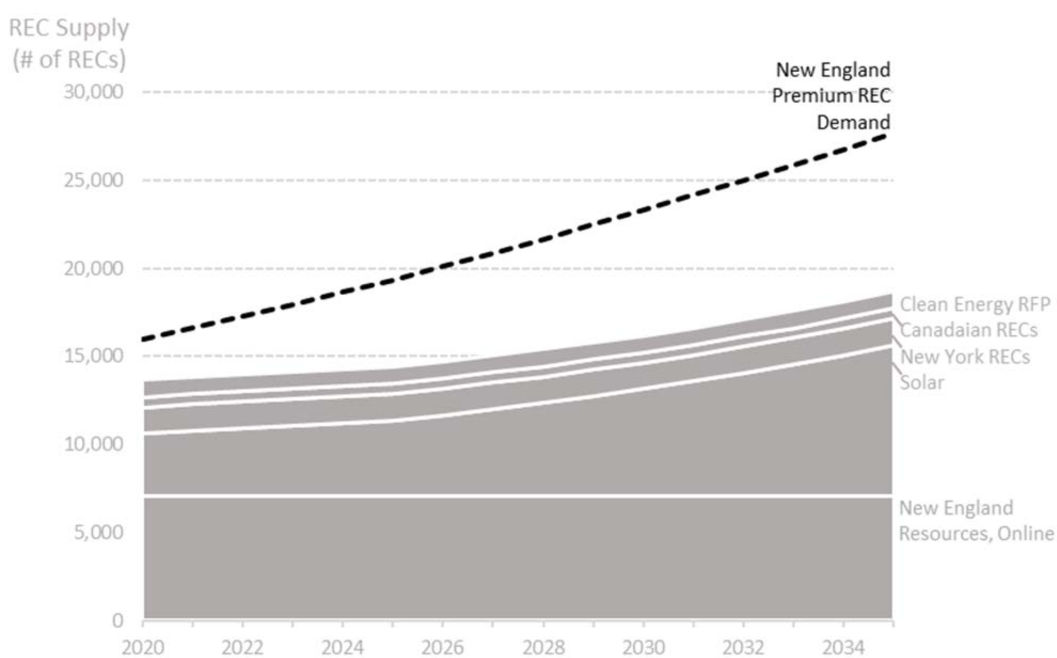

Figure III-1: Baseline REC Supply and Demand, 2020-2035

B. Potential Future Sources of Premium REC Supply

Beyond the baseline of projects currently online in New England and neighboring regions and forecasted solar, there are several categories of projects which could meet future growth in demand for Premium Class I RECs. These include:

- Additional imports from New York due to expiring NY REC contracts;
- Offshore wind projects procured by Massachusetts under Section 83C of the 2016 Energy Diversity Act; and
- Class I renewable energy procured by Massachusetts under Section 83D of the 2016 Energy Diversity Act.

We assessed the potential for RECs from each of the above categories individually and in combination. This analysis is described more fully below.

New York Imports

As part of the compliance with the New York RPS, the New York State Research and Development Authority (NYSERDA) conducted nine solicitations for renewable energy between 2005 and 2016. Each solicitation resulted in NYSERDA signing 10-year REC contracts with projects that will likely be in operation well beyond the contract period. As these contracts expire between 2016 and 2026, a significant potential new source of Premium Class I RECs for export from New York to New England may become available. The majority of the projects procured under the NYSERDA process would qualify for Premium Class I RECs in New England if they are successfully delivered to ISO New England and these would not meet the eligibility requirements for Tier 1 of New York's newly adopted Clean Energy Standard if they were online before January 1, 2015.[5] This means that there is a group of New York projects that could sell RECs to the New England market as their contracts with NYSERDA expire.

There is significant uncertainty regarding the likelihood of these Premium Class I RECs from New York resources entering the New England market. There is currently no path for these resources to continue to sell RECs to entities complying with the New York RPS, and some resources have already started selling RECs into New England. However, New York's aforementioned Clean Energy Standard has and aggressive target of a supply portfolio consisting of 50% renewable energy by 2030. It is possible that rules or regulations may be adopted to allow these older renewable projects to contribute to these goals, in which case they would not be able to sell Premium Class I RECs into New England.

Massachusetts 83C Offshore Wind

Section 83C of the Energy Diversity Act requires the distribution utilities in Massachusetts solicit proposals for 1,600 MW of offshore wind energy between 2017 and 2027. The first RFP was

[5] New York State Clean Energy Standard RES Tier 1 Certification: Application Instructions and Eligibility Guidelines, page 9. https://www.nyserda.ny.gov/All-Programs/Programs/Clean-Energy-Standard/Renewable-Generators-and-Developers/RES-Tier-One-Eligibility

issued on June 29, 2017[6] and states that the distribution utilities are looking to procure 400 MW of offshore wind energy, but would procure up to 800 MW if a larger project is likely to produce significantly greater benefits to ratepayers than a 400 MW project. For the purposes of future REC supply, we have assumed that 400 MW tranches of offshore wind will come online in 2024, 2026, 2028 and 2030.

Massachusetts 83D Clean Energy

The Section 83D RFP seeks bids for supplies of incremental Clean Energy, including resource eligible for Class I RECs. NECEC Bid 2 has the potential to contribute [redacted] million RECs to the regional market supply from the [redacted] MW of incremental wind capacity.

C. Summary of Premium Class I REC Supply and Demand

For this analysis, Daymark has assumed New England Premium Class I REC demand is met by a supply portfolio consisting of the baseline resources, new offshore wind under Section 83C, and New York resources described above. These resources are sufficient to meet regional RPS requirements in nearly all years, with a small shortage in the early years. The addition of the NECEC RECs reduces the need for NY RECs to comply with the RPS requirements. In this approach, the NECEC RECs represent the last Premium Class I RECs needed for the region to comply with RPS requirements. This approach is similar to the evaluation method used for the Three State Clean Energy RFP.

Figure III-2 below shows the New England Premium Class I REC supply and demand balance assumed for this analysis, including the 1.1 million Premium Class I RECs offered in NECEC Bid 2.

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6 https://macleanenergy.com/2017/06/29/section-83c-rfp-for-long-term-contracts-for-offshore-wind-energy-projects-issued/

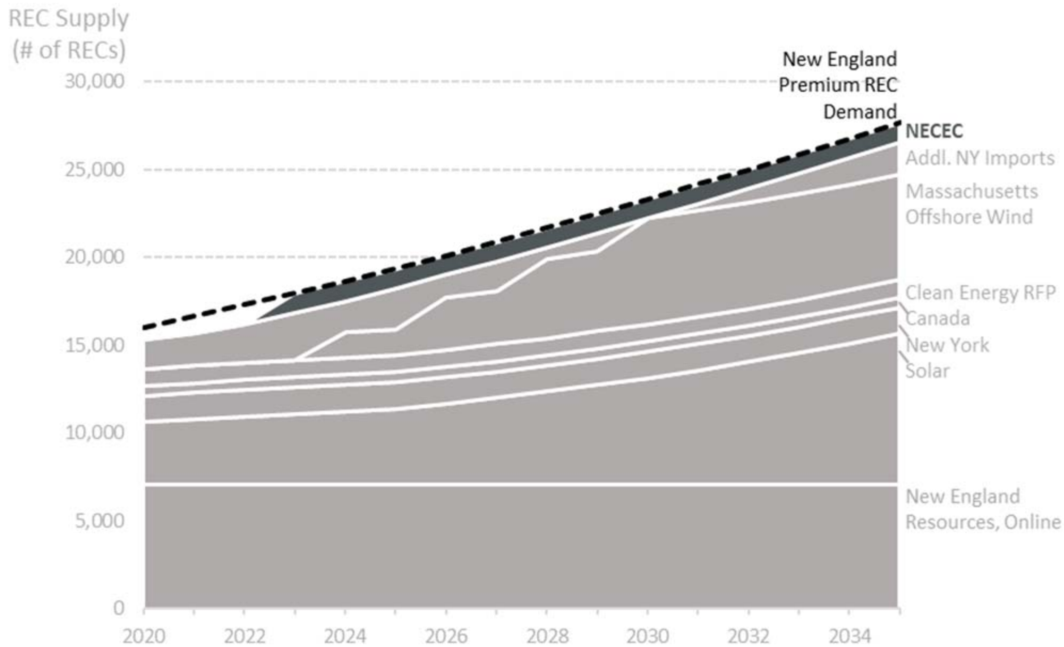

Figure III-2. New England Premium Class I REC Supply and Demand, with NECEC RECs

IV. REC PRICES

This section provides detail on market pricing for Premium Class I RECs and describes Daymark's methodology for determining prices used in the REC mark-to-market analysis in the Daymark Report.

The Premium Class I REC market is a bilateral market with trades generally occurring between two parties facilitated by a broker. Transactions on the bilateral market can be a onetime deal or longer term deals for RECs from a Class I facility. Pricing for these transactions is influenced by traditional market economics (supply and demand), as well as policy provisions, including the statutory ACP price.

A. Alternative Compliance Payments

ACPs provide a way for compliance entities to meet their requirement levels without the purchase of RECs and were instituted to provide a cap on the cost exposure of load-serving entities (LSEs) during shortage conditions. Use of ACP increases as conditions approach or are at shortage conditions. In most states, ACPs are set at a rate that increases with inflation; Connecticut is the exception, where the ACP is static at $55/MWh. Table IV-1shows ACP levels for 2017.

Premium RPS Class	2017
CT Class I	$55.00
MA Class I	$67.70
NH Class I	$56.02
NH Class II	$56.02
RI New	$67.71

Table IV-1. Premium RPS Class ACP rates ($/MWh)

B. Historical New England Short-Term Bilateral Market REC Prices

Historically the short term bilateral market REC prices in New England have hovered just below ACP in times of shortage and have dropped considerably below ACP in times of surplus. This is apparent in the graph of Massachusetts, Connecticut and Rhode Island Premium Class I REC prices included as Figure IV-1, below. REC prices were close to ACP in early 2008 and between 2011 and 2014 when there were shortages of RECs, and the price dropped as low as $12 per MWh between 2009 and 2010 when there was a surplus. Since the beginning of 2014, prices have trended lower, and currently the New England REC prices are between $20-$30/MWh.

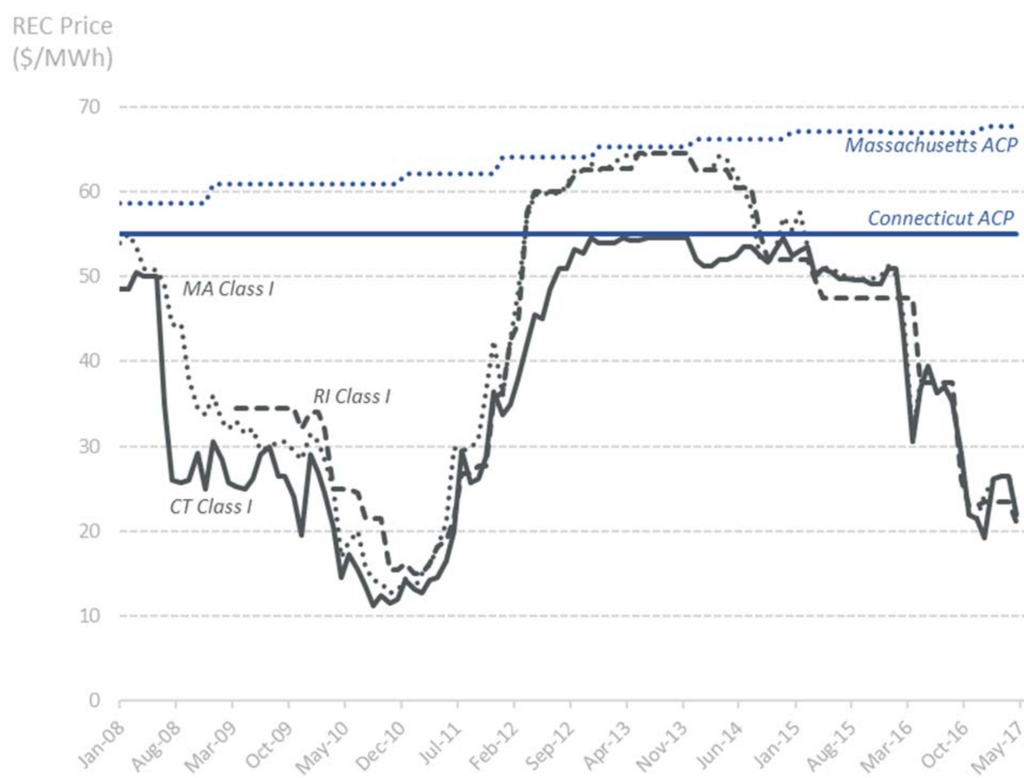

Figure IV-1: Historic Premium Class I REC Prices 2008-Present

C. Projected REC Prices During Study Period

The historical view of REC pricing in New England shows significant volatility over time. This volatility was generally caused by alternating periods of REC shortage and surplus. As the market matures, prices will tend towards a cost-based equilibrium price. In this future state, the REC market prices will reflect the revenue needed for a renewable project to be financially viable. Essentially, this will be the cost of the construction and ongoing operation of the project, net of the revenue the project will receive in the energy market.

Daymark developed a forecast of future REC market prices using this approach.[7] For the cost of the project, we used an estimate of levelized cost of energy (LCOE) for a new wind project published by the U.S. National Renewable Energy Lab (NREL).[8] This LCOE value is $73.20/MWh (2015$), assuming a cost premium for project in the northeast.

Using the results of Daymark's production cost modeling, we forecasted the energy revenue a wind project would receive. The difference between the LCOE and the energy revenue yield the forecasted cost-based REC price. The long-term decline in REC prices reflects the overall increase in energy revenue over time.

The resulting values are used in the REC mark-to-market analysis that is a component of the Direct Contract Benefits determination in Section V. of the Daymark Report.

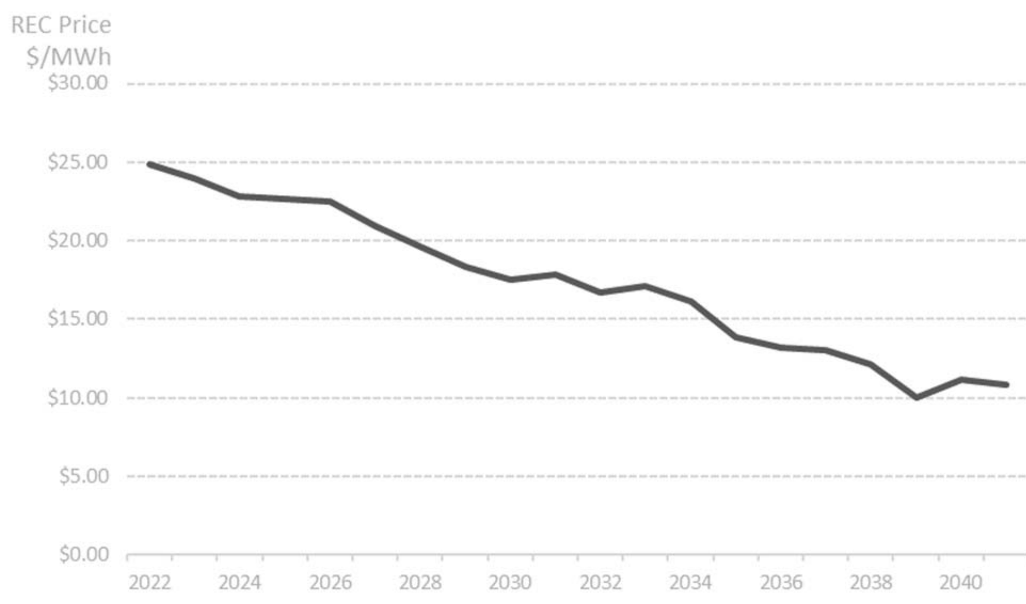

Figure IV-2. New England Premium REC price forecast

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7 This approach is designed to mimic the approach used in the evaluation of the Three State Clean Energy RFP.

8 NREL. *2015 Cost of Wind Energy Review.* May 2017. http://www.nrel.gov/docs/fy17osti/66861.pdf

APPENDIX C: CAPACITY MARKET MODELING AND ANALYSIS

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I. INTRODUCTION

Daymark Energy Advisors performed comprehensive analysis of the benefits and potential impacts of the New England Clean Energy Connect Project Bids (NECEC Bids) on ISO-NE wholesale markets, including an evaluation of the potential impact of the NECEC Bids on the ISO-NE capacity market. Daymark's NECEC Project Benefits report (the "Daymark Report") provides a high-level discussion of the results of our analysis, and this appendix provides additional detail supporting the analysis.[1]

Section II of this appendix provides additional details on the relevant ISO-NE Forward Capacity Market (FCM) rules and procedures that pertain to the opportunities for the NECEC Project to participate in the market.

Section III of this appendix describes the modeling methodology used to prepare the capacity market analysis in the Daymark Report. Daymark has developed a proprietary capacity market model to simulate the ISO-NE Forward Capacity Auction (FCA) process and forecast the impact of various market conditions or new resources (such as NECEC) on FCA outcomes.

1 See Section IV.E of the Daymark Report.

II. ISO-NE CAPACITY MARKET PROCEDURES

The NECEC Bids will provide a large source of clean, firm, low-cost capacity which will be eligible to be offered into the ISO-NE FCM. The NECEC Bids will be new capacity located outside the ISO-NE market that relies on an Elective Transmission Upgrade (ETU) to deliver capacity to New England, and are supported by long-term contracts for their energy output. The FCM rules have several special processes that apply to capacity resource offerings of this type and this section describes the FCM provisions that would apply to the NECEC Bids and the process of qualifying and clearing the capacity market.

A. Resource Qualification

The first key step for participation in the ISO-NE FCM is to qualify the resource capacity for the market. ISO-NE has established a multi-step qualification process. Each type of capacity resource (generation, demand or imports) has a distinctive qualification process designed to certify the reasonableness of the resource's availability at the beginning of the period and to determine the amount of qualified capacity it can supply after adhering to various ISO-NE requirements.

In 2015, ISO-NE updated it capacity market rules to incorporate the participation of ETUs. An ETU is generally comprised of a transmission element with interconnection points within the New England Control Area tied to one or more generation resources.

To qualify as an ETU, the entity that will provide capacity must demonstrate that there is either sufficient capacity across the entire exporting system or a dedicated resource to deliver capacity to New England up to the requested capacity supply obligation at any time throughout the year.

An ETU must also satisfy the reliability criteria mandated by the ISO-NE tariff. Schedule 25 of the ISO-NE Open Access Transmission Tariff describes the interconnection standards for ETUs: (i) the Network Capability Interconnection Standard (NCIS) and (ii) the Capacity Capability Interconnection Standard (CCIS). ISO-NE conducts transmission evaluation studies to assess compliance with each standard upon request from the owner of the facility. The studies for the NCIS – also known as Minimum Interconnection Standard – assess the impact to the New England Transmission system's reliability, stability, and operability from the construction of the ETU or ETU incremental upgrades. The studies for the CCIS assess the incremental impact of the new resource associated with an ETU on the New England Transmission system's reliability, stability, and operability under the assumption that all existing resources are operating without a need for redispatching and the capacity from this new resource is deliverable to the rest of the load zone. The results of these studies provide a list of network upgrades needed to meet the NCIS and/or the CCIS.

The NCIS is assessed in the Interconnection System Impact Study (SIS) while the CCIS is evaluated in the Capacity Network Resource Group Study (CNR Study). In order to participate in ISO-NE's FCM and eventually obtain a Capacity Supply Obligation, a facility must adhere to the CCIS in addition to meeting the NCIS requirements.

Once the resource and the ETU have been evaluated under the relevant standards and have demonstrated that the subject capacity is available to be delivered to New England, ISO-NE will qualify the import resource associated with an ETU.

B. Capacity Offer Pricing and Mitigation

As with all capacity bidding into the ISO-NE FCM, the import capacity associated with the ETU must submit an offer price for the capacity. After the completion of the qualification process, ISO-NE requires the submission of the ETU's capacity offer to be reviewed and possibly mitigated by ISO-NE's Internal Market Monitor (IMM). The purpose of the IMM's review is to prevent capacity from offering at uncompetitively low prices while being subsidized by out-of-market contracts.

All resources have specific offer price review thresholds set in the FCM rules that have been deemed as the lowest price resources can offer their capacity in without being reviewed by the IMM. These prices are called Offer Review Trigger Prices (ORTP). If a developer of a specific resource seeks to offer its capacity in the market at a price below the ORTP, it must provide documentation to the IMM that justify that action. The rules establish the highest ORTP price for resources associated with ETUs, effectively making all ETU price offers subject to review by the IMM. The table below provides the ORTP for different resources including those associated with ETUs for FCA 11:

Technology Type	**Offer Review Trigger Price ($/kW-mo)**
FCA 11 Starting Price: $18.624/kW-mo	
Combustion Turbine	$13.933
Combined Cycle Gas Turbine	$9.465
On-shore wind	$5.698
All other technology types	Starting price
Import associated with an ETU	Starting price + $0.01
Single new resource with a transmission investment to increase the import capability to New England	Based on generation technology type
Import capacity resource backed by a pool or an existing resource that is not associated with an increase in transmission	Starting price + $0.01

Table 1. FCA 11 Offer Review Trigger Prices

ETU project developers provide detailed net cost projections for both transmission and generation assets included in the proposed resource associated with the ETU and will be utilized in delivering the offered capacity. Some of the critical elements included in the offer are capital and other fixed costs of the transmission in both regions (if external) and the cost of any new generation capacity needed to support the transaction, both amortized over some reasonable time-period.

This net cost of providing capacity to New England is adjusted by the net energy revenues realized by the new or incremental transmission and generation. Based on the current methodology, the IMM calculates these revenues based on projected wholesale market prices for energy in New England minus any variable cost or opportunity cost for the entity to provide the energy in other regions. Under the existing ISO-NE process, any probable contract prices for clean energy attributes or energy delivered by the ETU if any, cannot be counted in place of the wholesale market price. One exception exists if the clean energy attributes available to the ETU are considered “broadly available” to other resources such as Renewable Energy Certificates (RECs). In that case, the IMM may consider these additional streams of revenues in place of the projected wholesale energy prices.

The last step in the capacity offer review process is translating the annual net cost from the previous step into a capacity supply offer in terms of cost per kW-month. This calculation includes the division by the number of kW-months the resource can be relied on to serve the New England power system.

When the IMM completes its review, it will set a minimum capacity offer price for the resource associated with the ETU. The developer can offer this resource at a price at or above the IMM minimum capacity offer price but not below.

C. Capacity Clearing Process

Once the resource associated with the ETU has qualified its capacity and has received an approved minimum capacity offer price, the resource can bid its capacity into the FCA. The resource only receives a capacity supply obligation if it clears, based on its offer price. Depending on the specific parameters of the capacity offers, the amount of MW cleared can be affected by whether this resource is the marginal resource in the FCA or not. If the resource only clears a portion of its capacity, it will only receive payments for the MWs cleared in the FCA and not for the entire qualified capacity.

Import resources associated with ETUs must bid in and clear the capacity market each year in order to receive an obligation.[2] This treatment is consistent with how ISO-NE treats other imports into New England from neighboring regions that do not have an executed long-term contract. In order for an import capacity resource associated with an ETU to maintain its Capacity Network Import Interconnection Service as described in the qualification section above, it must

[2] This differs from new conventional supply generators that are guaranteed to receive a locked-in capacity price for the first seven years after it first clears.

offer into each FCA. Otherwise, the qualified MWs may be adjusted by the ISO depending on activity by other bidders in the market.[3]

D. Capacity Market Uncertainty

Daymark conducted its analysis on the participation in and impact of the NECEC Bids on the ISO-NE FCM based on the best information currently available regarding the market rules. However, there are a number of key uncertainties about the future operation of the market that could significantly impact this analysis, with two examples of such uncertainties described below.

First, FCA results are fundamentally the result of discrete decisions by individual market actors. Perceptions of market opportunity and risk can impact bidding behavior and determine future market results. For example, the new Pay for Performance rules impose penalties on cleared capacity resources that fail to perform when called. The implementation of these rules introduces new risk to resources participating in the market, particularly older resources that may not be as reliable. This has the potential to affect market behavior in the future in ways not fully captured in this analysis.

Second, in an effort to address the participation of renewable resources in the FCM, ISO-NE has recently proposed a modification to the FCM to add a secondary auction, called a “substitution auction”. The point of this auction would be to allow new renewable resources, which may be subsidized under a policy mechanism such as the Production Tax Credit, to receive a capacity supply obligation transferred from an existing resource that wishes to retire. The substitution auction would determine the price paid to the renewable resource for its capacity. A rule change such as this could impact the market in various ways, but one result could be that older resources may be more inclined to retire if they can transfer their obligation for less than the clearing price and retain a portion of the capacity revenue.

[3] Section III.13.1.3. Import Capacity of ISO-NE Market Rule 1

III. DAYMARK CAPACITY MARKET MODELING

Using a proprietary simulation model, Daymark has evaluated future expectations for the New England capacity position, with and without the NECEC in service. This modeling and analysis contributed to Daymark's evaluation in two ways: First, the capacity market modeling generates the capacity buildout and retirement schedule for the production cost modeling described in Appendix A; and second, the Daymark model is used to calculate the indirect impact of the project on the capacity market.[4]

This section of the appendix describes the model's operation and key assumptions.

A. Model Overview

The Daymark ISO-NE FCM model simulates the annual FCAs that ensure sufficient capacity is available to meet peak demand in the region. The model uses inputs reflecting resource economics for new additions and existing generation units to determine the timing and quantity of new additions and retirements in the market, incorporating several additional factors which reflect actual components of the market, such as capacity imports, energy efficiency, and renewables.

The model uses the ISO-NE demand curve to determine the market clearing price for each auction, which in turn determines the retirements and buildout. As the auctions progress through the study period, clearing prices impact the economics of existing units, and when going-forward costs exceed the capacity revenue, a resource may be retired. The loss of that capacity has a consequent impact on the clearing price. When the clearing price is sufficient to attract new entrants to the market, additional capacity is added, again impacting the FCA clearing price.

The result of the model is a schedule of retirements of existing resources and additions of new generic capacity in the region, as well as the annual FCA clearing prices.

The Section B below provides additional detail on the key elements of the model.

B. Key Components

Net Installed Capacity Requirement

The key component of the model on the demand side is ISO-NE's reliability requirement for capacity, known as the Net Installed Capacity Requirement (NICR). NICR is fundamentally a forecast of peak system load, plus an additional reserve margin. For FCA 11 (delivery in June 2020 through May 2021), ISO-NE established an NICR of 34,075 MW, which results in a 15% reserve margin above the 29,600 MW projected summer peak load for 2020, net of behind-the-

[4] See the Daymark Report, Section IV.E.

meter solar photovoltaics. For subsequent years, we estimate the NICR based on the ISO-NE's peak load forecast, assuming approximately the same reserve margin (15%) found in FCA 11. The resulting NICR grows by an average of 320 MW per year from 34,075 MW in 2020 (FCA 11) to 37,280 MW in 2030 (FCA 21).

Existing Cleared Capacity

As a starting point for FCA 12, the model uses the cleared FCA 11 capacity quantities, both on an aggregate system-wide basis, and for individual resources. The total cleared capacity in FCA 11 was 35,835 MW, including in-region capacity as well as imports. The actual qualified capacity for an individual resource can change year-to-year according to the resource's reliability performance (based on forced outage history) and the resource owner's designation of offered capacity. These changes can impact the overall capacity supply in the region and therefore impact clearing prices, timing of retirements, new capacity build, etc. However, since these changes are based on actual unit operation and bidding decisions, we have not attempted to forecast such changes and instead assume that the qualified and offered capacity of existing units remains the same as FCA 11.

New Energy Efficiency and Renewable Capacity

New energy efficiency (EE) and renewable capacity are eligible to participate in the FCM and receive CSOs, and have been significant sources of new supply in recent auctions.

The development of these resources and their participation in the FCM is dependent on dynamics that are distinct from the supply and demand curves that generally determine how conventional resources participate in the market. Therefore, rather than incorporate these resources in the annual market-clearing process, we have treated these resources separately in our model.

For EE, we have assumed that the existing capacity quantity cleared in FCA 11 persists, and that new EE capacity clears the FCAs in quantities based on the ISO-NE EE forecast prepared as part of the 2016 CELT report. The ISO-NE forecast extends through 2026, with new incremental EE declining each year. We have assumed a continuation of the forecasted trajectory.

Renewable capacity has some additional requirements for qualifying and clearing in the FCA due to its intermittency and any subsidies received (such as the Production Tax Credit). In addition, ISO-NE has proposed changes to the FCM to implement a secondary auction for subsidized resources that may impact the participation of renewables in the market going forward. As a result, there is significant uncertainty regarding the participation of renewables in the FCM.

For this analysis, we have assumed that new renewable capacity associated with the offshore wind projects procured under Section 83C will clear the market. We have assumed a 30% capacity credit for this capacity.

Imports

Capacity from regions interconnected with ISO-NE, including Quebec, New Brunswick, and New York, is eligible to participate in the FCM and receive CSOs, subject to certain rules and processes. In FCA 11, the following imports cleared the market.

External Interface	Capacity Supply Obligation
New York AC Ties	539.4 MW
New Brunswick	200 MW
Phase I/II HQ Express	441 MW
Hydro-Quebec Highgate	55 MW

Table 2. FCA 11 Cleared Import Capacity

Our model uses a supply curve of imports reflecting recent FCA results, such that the amount of imports increases with the clearing price.

Net Cost of New Entry (CONE)

The key assumption determining the timing and quantity of new capacity additions is the Net CONE. This price represents the estimated capacity revenue that would be needed for a new resource to be economically viable in the ISO-NE market, calculated as the cost to develop and construct the resource, plus ongoing operating expenses, minus energy market revenues. In Daymark's model, it is the price that is compared to the clearing price to signify when it is economic to build new capacity.

ISO-NE periodically conducts a study to calculate the Net CONE for various types of new resources. The most recent study, completed in January 2017, determined that for FCA 12, the Net CONE of a new combined cycle would be $10.00/kW-mo and the Net CONE for a combustion turbine would be $8.04/kW-mo. This is an administratively-determined price that is used to define the points of the demand curve and create the starting price.

The ISO estimates reflect generic assumptions and forecasts of costs and revenues, and generally does not reflect actual bids from market entrants. In fact, several new resources cleared the market in FCA 10, when the clearing price was just over $7.00/kW-mo. This indicates that new generation projects are viable when clearing prices are lower than the ISO-NE Net CONE value.

For the purposes of our modeling, Daymark assumed an annual Net CONE value for new resources equal to the $7.00/kW-mo value, escalated at inflation over time. Therefore, the model will clear new capacity when the clearing price exceeds Net CONE.

Demand Curve

The ISO-NE FCM demand curve determines the clearing price at various capacity levels. In recent years, ISO-NE has modified its demand curve multiple times in attempts to better reflect the value of increased reliability resulting from additional procured capacity.

Most recently, in 2016, ISO-NE revised how it constructs the demand curve from a downward-sloping straight line, to a Marginal Reliability Impact (MRI) curve that is convex to the origin and generally shifted to the left (lower price at the same capacity level). Daymark's model incorporates this new MRI curve into the auction simulation.

Resources at Risk of Retirement

Daymark's capacity model evaluates the going-forward cost and potential retirement of 86 existing generators in New England with a total qualified capacity of more than 12,000 MW. Daymark identified the list of units to be evaluated by filtering out units by age, resource type, and primary fuel.

After defining the list of resources that would be evaluated in the model, Daymark created annual going-forward cost (or "delist bid") estimates representing the revenue needed by the resource to be economically viable. This delist bid is constructed using annual net energy revenue (energy revenue net of all variable costs of generation) forecasts from our production cost modeling, and forecasts of fixed O&M expense for each resource.

C. Simulation Process

The key assumptions and components outlined in the previous section provide the basis for the model simulations. The Daymark FCM model dynamically generates annual FCA clearing prices incorporating these various influencing factors.

For each annual auction simulated, the model incorporates resource retirements when delist bids exceed clearing prices, new resource additions when the clearing price exceeds Net CONE, and changes in imports based on the import supply curve described above. Since each of these changes in cleared capacity also impact the clearing price, the process dynamically determines the appropriate capacity changes for each auction.

Once the final schedule of retirements and buildout is determined, the final stage is to allocate the new capacity buildout by type (CC or CT) and location. This process incorporates zone-specific conditions, such as load growth and cumulative capacity resource retirements throughout the study period, to determine the most appropriate location for the buildout. The type of capacity addition is similarly determined based on market conditions (primarily energy price) such that when energy prices are high, more CCs are built, and when prices are low, more CTs are added.

APPENDIX D: RESUMES

SEPTEMBER 27, 2017

I. DANIEAL E. PEACO

Daniel E. Peaco

Principal Consultant

SUMMARY

Daniel Peaco is a Principal Consultant, Chairman, and Past-President at Daymark Energy Advisors, a leading provider of integrated policy, planning and strategic decision support services to the North American electric and natural gas industries.

Mr. Peaco has 35 years of experience in the electric industry, both as a utility planning practitioner and, for the past 20 years, as a consultant to the industry. His consulting practice has included engagements relating to strategic planning, competitive electric markets, integrated resource planning evaluation of generation asset investments, renewable energy policy, transmission planning, competitive procurement and power contracts, and industry restructuring.

Prior to joining Daymark Energy Advisors, he held management and planning positions in power supply planning at Central Maine Power, CMP International Consultants, Pacific Gas & Electric, and the Massachusetts Energy Facilities Siting Council. He holds degrees from M.I.T. and Dartmouth College.

EMPLOYMENT HISTORY

Daymark Energy Advisors, Inc.	*Boston, MA*
Chairman	Aug 2015-current
President	2002-July 2015
Managing Director	*1996-2002*
Central Maine Power Company	*Augusta, ME*
Manager, Industrial Marketing and Economic Development	1995-96
Principal, CMP International Consultants	*1993-95*
Director, Power Supply Planning	1987-93
Power Supply Planning Analyst	1986-87
Pacific Gas & Electric Company	*San Francisco, CA*
Power Supply Planning, Hydropower Planning, Cogeneration Contracts	1981-86
Massachusetts Energy Facilities Siting Council	Boston, MA
Planning Engineer	*1978-79*

EDUCATION

Thayer School of Engineering, Dartmouth College	*Hanover, NH*
M.S. in Engineering Sciences, Resource Systems and Policy Design	1981
Massachusetts Institute of Technology	*Cambridge, MA*
B.S. in Civil Engineering, Water Resource Systems	1977

PUBLICATIONS, PRESENTATIONS & CONFERENCES

MCPC Project Benefits; Quantitative and Qualitative Benefits, Confidential Report prepared for Central Maine Power regarding the benefits of the Maine Clean Power Connection, a 345 kV transmission expansion accompanied by 1100 MW of wind energy project development offered in the Massachusetts RFP for Clean Energy Resources, July 27, 2017. Lead Consultant and Principal Author.

NECEC Project Benefits; Quantitative and Qualitative Benefits, Confidential Report prepared for Central Maine Power and H.Q. Energy Services regarding the benefits of the New England Clean Energy Connection, 1200 MW HVDC transmission expansion accompanied by 1090 MW of hydropower and wind energy project development offered in the Massachusetts RFP for Clean Energy Resources, July 27, 2017. Lead Consultant and Principal Author.

Evolving Practices in Electric Company Resource Planning: Key Insights from a Review of 15 Recent Electric Company Resource Plans, report prepared for the Electric Power Research Institute. May 2017. Lead Consultant and Principal Author.

Clean Energy Procurement Mechanisms, instructor for Post-Conference Workshop at the EUCI 3rd Annual U.S./Canada Cross-Border Energy Trade Summit, Boston, Massachusetts, March 2, 2017.

CHP Economic Factors: Electric and Natural Gas Market Trends, keynote presentation for the Efficiency Maine Combined Heat & Power Conference, Portland, Maine, September 29, 2016.

Changes in IRP in Market Transitions, Where Has It Happened?, presentation to the EUCI 16th Annual Integrated Resource Planning Conference, Long Beach, March 22, 2016.

MREI Project Benefits; Direct, Indirect, Qualitative and Other Benefits, prepared for Central Maine Power Company and Emera Maine regarding the benefits of the Maine Renewable Energy Initiative, a 345 kV transmission expansion accompanied by 1200 MW of wind energy project development. January 28, 2016. Lead Consultant and Principal Author.

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Need For and Alternative To (NFAT) Review of Manitoba Hydro's Proposal for the Keeyask and Conawapa Generating Stations, Initial Expert Analysis Report prepared for the Manitoba Public Utilities Board. January 24, 2014. Supplemental Report. February 28, 2014. Lead Consultant and Principal Author.

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Regarding Tri-State G&T's Cost to Serve Its Nebraska Loads and the Nebraska Power Supply Issues Group Loads, prepared for the Nebraska Power Supply Issues Group, two public power districts and two member-owned electric utilities in Western Nebraska. December 2012. Lead Consultant and Principal Author.

Independent Valuation Opinion for the Vernon Station in the Town of Hinsdale, NH, prepared for the TransCanada Hydro regarding the value of a 32 MW hydropower asset. November 2012. Lead Consultant and Principal Author.

Independent Valuation Opinion for the Comerford and McIndoes Stations in the Town of Monroe, NH, prepared for the TransCanada Hydro regarding the value of 179 MW hydropower assets. November 2012. Lead Consultant and Principal Author.

Independent Opinion Regarding the Market Value of Brassua Hydro LP Assets, prepared for the Owners of Brassua Dam regarding the value of a 4 MW hydropower asset. November 2012. Lead Consultant and Principal Author.

Independent Opinion Regarding Amortization Reserve of Brassua Hydro LP, prepared for the Owners of Brassua Dam regarding the amortization reserve value of a 4 MW hydropower asset. November 2012. Lead Consultant and Principal Author.

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2010 Comprehensive Plan for the Procurement of Energy Resources, Report prepared for the Connecticut Energy Advisory Board. April 27, 2010. Lead Consultant and Principal Author.

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Need for Power Supply: The New England Power Pool and the State of Rhode Island, March 1999, prepared for Indeck – North Smithfield Energy Center.

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EXPERT TESTIMONY

Public Service Commission of Utah Docket No. 17-035-39	Division of Public Utilities Department of Commerce	Expert testimony regarding PacifiCorp's application for pre-approval of its proposed repowering of 999 MW of existing wind turbines, including issues regarding PTC qualification, economic benefits analysis, and project risks.		
		Preflied Testimony	September 20, 2017	
Superior Court Windham Unit State of Vermont	TransCanada Hydro Northeast, Inc.	Expert testimony regarding the headwater benefits value of Moore Station, a 190 MW hydropower facility in appeal of appraised value in the Town of Waterford, Vermont.		
		Valuation Report Deposition testimony	November 11, 2016 December 13, 2016	
Superior Court Windham Unit State of Vermont	TransCanada Hydro Northeast, Inc.	Expert testimony regarding the valuation of a Harriman Station, a hydropower facility (39 MW) in appeal of appraised values in the town of Whitingham, VT.		
Docket No. 413-9-13 Wmcv		Valuation Report Deposition	September 19, 2016 November, 2016	
Massachusetts Energy Facilities Siting Board Docket No. EFSB 15-06	NRG Energy NRG Canal 3 Development LLC	Testimony regarding NRG's application for siting approval of a proposed 350 MW duel-fueled combustion turbine. Testimony addressed alternative technology assessment and consistency with energy and environmental policies of the Commonwealth, considering reliability, regional fuel diversity, global warming solutions policy, and renewable energy integration.		
		Direct Testimony Pre-filed Testimony Oral Testimony	December 2, 2015 April 4, 2016 September 9 & 14, 2016	
Georgia Public Service Commission Docket No. 40161	Georgia Public Service Commission Public Interest Advocacy Staff	Witness sponsoring testimony regarding integrated resource planning methods, renewable energy economics and policy, fuel diversity considerations in resource planning.		
		Written Testimony Oral Testimony	May 6, 2016 May 18, 2016	
Superior Court Windham Unit State of Vermont	TransCanada Hydro Northeast, Inc.	Expert testimony regarding the headwater benefits value of the Somerset Reservoir in the Deerfield River. Headwater benefits determination were raised as a key issue in the Town of Somerset's valuation of the facility for property tax assessment.		
Docket No. 470-10-13 Wmcv		Headwater Benefits Report Deposition testimony	November 13, 2015 February 2, 2016	
Superior Court Windham Unit State of Vermont	TransCanada Hydro Northeast, Inc.	Expert testimony regarding the valuation of a the Bellows Falls hydropower facility (49 MW) in appeal of appraised values in the town of Rockingham VT.		
Docket No. 547-11-12 Wmev		Valuation Report Deposition Oral Testimony	April 23, 2015 February 4, 2014 May 11, 12 and 13, 2015	

Rhode Island Superior Court PC No. 2012-1847	TransCanada; Ocean States Power Holdings, Ltd.	Expert testimony regarding the valuation of a 540 MW combined cycle power plant in appeal of an appraisal conducted for the Town of Burrillville, RI. Prepared analysis of unit operations and revenue forecasts.	
		Report for 12/31/2010	December 19, 2012
		Report for 12/31/2011	July 17, 2014
		Deposition Testimony	May 2, 2015
Oklahoma Corporation Commission Cause No. PUD 201400229	OK Cogeneration	Testimony regarding Oklahoma Gas & Electric Company Application for pre-approval of its Mustang Modernization Plan, addressing planning for retirement of 430 MW of gas-fired steam generation and addition of 400 MW of Combustion turbine generation, cost pre-approval, and Requirements for competitive procurement and alternatives analysis.	
		Pre-filed Testimony	December 16, 2014
		Oral Testimony	March 18-19, 2015
Maine Public Utilities Commission Docket No. 2014-048	Central Maine Power	Testimony regarding CMP's application for approval Maine Power Connection Transmission Project. Testimony addressed economic benefits associated with Interregional transmission connection and associated wind energy development benefits.	.
		Expert Report	September 5, 2014
		Rebuttal Report	February 27, 2015
		Oral Testimony	September 18, 2014 March 31, 2015
US District Court Colorado Civil Action No. 10-CV-02349-WJM-KMT	Nebraska Power Supply Issues Group	Expert testimony regarding Tri-State G&T cost to serve five Nebraska members.	
		Expert Report	December 31, 2012
		Deposition Testimony	February 27, 2013
		Oral Testimony	May 19, 2014
Public Utilities Board Manitoba, Canada Needs For and Alternatives To (NFAT)	PUB NFAT Panel	Independent Expert (IE) for the review of Manitoba Hydro's Hydropower and Transmission Development Plan for 2,160 MW of hydro capacity at two locations, a 500 kV transmission line to Minnesota, and associated export contracts.	
		Expert Reports I	January 24, 2014
		Expert Reports II	February 28, 2014
		Oral Testimony	April 8, 9, 10, 11, 2014
Superior Court State of Vermont Docket No. 423-9-12 Wmcv Docket No. 547-11-12 Wmev Docket No. 244-9-12 Cacv Docket No. 245-9-12 Cacv	TransCanada Hydro Northeast, Inc.	Expert testimony regarding the valuation of a four hydropower facilities totaling 260 MW in appeal of appraised values in the towns of Vernon, Rockingham, and Barnet VT.	
		Valuation Report	July 15, 2013
		Deposition	February 4, 2014

Arbitration AAA Case No. 11 198 Y 002014 12	City of Burlington, VT Burlington Electric Dept.	Expert testimony regarding the valuation of a 7 MW hydropower facility and the determination of fair value for transfer of ownership of the asset. Valuation Report June 21, 2013 Rebuttal Report July 26, 2013 Deposition Testimony September 12, 2013 Oral Testimony October 4, 2013
Arkansas Public Service Commission Docket No. 12-069-U	General Staff of the AK Public Service Comm.	Testimony regarding the evaluation of Entergy Arkansas's proposed divestiture of its transmission business to ITC Holdings. Direct Testimony April 19, 2013 Surrebuttal Testimony June 7, 2013 Supplemental Testimony - Rate MitigationAug 15, 2013
Arbitration AAA Case No. 11 153 Y 02133 11	Owners of Brassua Dam FPL Hydro Maine LLP Madison Paper Industries Merimil Ltd Partnership	Expert testimony regarding the valuation of a 4 MW hydropower facility and the determination of amortization reserve obligations under FERC license provisions. Valuation Report November 1, 2012 Amortization Reserve Report November 1, 2012 Amortization Reserve Rebuttal November 15, 2012 Oral Testimony December 5, 2012
Arkansas Public Service Commission Docket No. 10-011-U	General Staff of the AK Public Service Comm.	Testimony regarding the evaluation of Entergy Arkansas's strategic reorganization options and request for authorization to transfer control of its transmission asset to the Midwest ISO. Oral Testimony May 31, 2012 Surrebuttal Testimony April 27, 2012 Direct Testimony March 16, 2012
Burrillville Board of Review	TransCanada; Ocean States Power Holdings, Ltd.	Expert testimony regarding the valuation of a 540 MW combined cycle power plant in appeal of an appraisal conducted for the Town of Burrillville, RI. Valuation Report January 4, 2012 Oral Testimony March 1, 2012
Oklahoma Corporation Commission Cause No. PUD 201100186	OK Corporation Commission OK Attorney General	Testimony regarding a 60 MW Wind Energy Purchase Agreement and Cogeneration deferral Agreement proposed by Oklahoma Gas & Electric Company, addressing cost pre-approval, and a requested waiver from competitive procurement requirements. Pre-filed Testimony February 8, 2012
Arkansas Public Service Commission Docket No. 10-011-U	General Staff of the AK Public Service Comm.	Testimony regarding the evaluation of Entergy Arkansas's strategic reorganization options upon its exit from the Entergy System Agreement. Oral Testimony September 9, 2011 Surrebuttal Testimony August 18, 2011 Supplemental Initial Testimony July 12, 2011 Initial Testimony February 11, 2011

State Corporation Commission of the State of Kansas	The Landowner Group	Testimony regarding the application of ITC Great Plains for a siting permit for a 345-kV Transmission Line addressing project need and route selection methodology.	
		Initial Testimony	April 18, 2011
Federal Energy Regulatory Commission (FERC) RM10-23-000	Maine Public Utilities Commission, et. al.	Expert Affidavit regarding economic analysis methodology for transmission project evaluation. Provided in reply comments on the FERC Transmission Planning and Cost Allocation NOPR.	
		Affidavit	November 12, 2010
Maine Public Utilities Commission Docket No. 2008-255	Central Maine Power	Testimony regarding CMP's application for approval the Lewiston Loop 115kV Transmission Project. Testimony addressed non-transmission alternatives.	
		Oral Testimony	November 16, 2008 December 14, 2010
		Rebuttal Testimony	November 8, 2010 August 27, 2010
Oklahoma Corporation Commission Cause No. PUD 201000092	OK Corporation Commission OK Attorney General	Testimony regarding a 99.2 MW wind farm power purchase agreement and green energy choice tariff proposed by Public Service Company of Oklahoma, addressing cost pre-approval, resource need, and competitive procurement requirements.	
		Pre-filed Testimony	October 5, 2010
		Oral Testimony	November 3, 2010
Oklahoma Corporation Commission Cause No. PUD 201000037	Oklahoma Attorney General	Testimony regarding a 198 MW wind farm proposed by Oklahoma Gas & Electric, addressing cost pre-approval, resource need, and competitive procurement requirements.	
		Pre-filed Testimony	June 11, 2010
Connecticut Dept. of Public Utilities Control (DPUC) Docket No, 10-02-07	Connecticut Energy Advisory Board (CEAB)	Lead witness sponsoring the CEAB's *2010 Comprehensive Plan for the Procurement of Energy Resources*.	
		Oral Testimony	June 2 & 3, 2010
Georgia Public Service Commission Docket No. 31081	Georgia Public Service Commission Public Interest Advocacy Staff	Witness sponsoring testimony regarding integrated resource planning methods, renewable energy, solar PV demonstration projects, and uncertainty analysis.	
		Written Testimony	May 7, 2010
		Oral Testimony	May 18, 2010

Maine Public Utilities Commission Docket No. 2008-255	Central Maine Power	Testimony regarding CMP's application for approval $1.5 B Maine Power Reliability Transmission Project. Testimony addressed non-transmission alternatives and economic benefits, economics of proposed solar alternative, wind energy development benefits. . Oral Testimony October 10, 2008 November 19, 2008 December 21, 2009 February 4, 2010 Rebuttal Testimony December 4, 2009 April 3, 2009
Oklahoma Corporation Commission Cause No. PUD 200900167	Oklahoma Attorney General	Testimony regarding a 102 MW wind farm proposed by Oklahoma Gas & Electric, addressing cost pre-approval, resource need, and competitive procurement. requirements. Pre-filed Testimony Sept 29, 2009
Oklahoma Corporation Commission Cause No. PUD 200900099	Oklahoma Industrial Energy Consumers (OIEC)	Testimony regarding a power contract pre-approval and recovery of Independent Evaluator costs of Public Service Company of Oklahoma. Pre-filed Testimony July 14, 2009
Connecticut Dept. of Public Utilities Control (DPUC) Docket No, 09-05-02	Connecticut Energy Advisory Board (CEAB)	Lead witness sponsoring the CEAB's *2009 Comprehensive Plan for the Procurement of Energy Resources*. Oral Testimony June 30, 2009
Connecticut Dept. of Public Utilities Control (DPUC) Docket No, 08-07-01	Connecticut Energy Advisory Board (CEAB)	Lead witness sponsoring the CEAB's *2008 Comprehensive Plan for the Procurement of Energy Resources*. This Plan is the first prepared under the State's new integrated resource planning statute. Oral Testimony August 28, 2008 September 22, 2008 October 3, 2008
Maine Superior Court Civil Action Docket No. cv-06-705	Worcester Energy Co., Inc.	Expert opinion regarding renewable energy and power procurement services. Pre-filed Report January 30, 2008 Oral Testimony March 18, 2009
Massachusetts Dept. Of Telecommunications And Energy Docket No. DTE/DPU-06-60	Russell Biomass	Testimony regarding economic, reliability and environmental need for renewable power in the Massachusetts and New England in support of Russell Biomass petition for a zoning exemption. Pre-filed Testimony June 2007 Oral Testimony October 30, 2007
Hawaii Public Utilities Commission Docket No. 04-0046	Hawaii Division of Consumer Advocacy	Testimony regarding Hawaii Electric Light Company's integrated resource plan. Pre-filed Testimony September 28, 2007 Oral Testimony November 26, 2007

Nevada Public Utilities Commission Docket No. 06-12002	Nevada Attorney General Bureau of Consumer Protection	Testimony regarding the prudency of Sierra Pacific Power Company in its purchased power expenses for the period December 2001 through November 2002. Pre-filed Testimony — September 14, 2007
Oklahoma Corporation Commission Cause No. PUD 2005516 Cause No. PUD 2006030 Cause No. PUD 2007012	Oklahoma Attorney General	Testimony regarding a 950 MW coal-fired generation facility proposed by Public Service of Oklahoma and Oklahoma Gas & Electric, including IRP, competitive procurement, and construction financing issues. Pre-filed Testimony — May 21, 2007 Rebuttal Testimony — June 18, 2007 Oral Testimony — July 26, 2007
Oklahoma Corporation Commission Cause No. PUD 2002-038 REMAND	Oklahoma Industrial Energy Consumers (OIEC)	Testimony regarding a power contract proposal of Lawton Cogeneration and the pricing analysis of Public Service Company of Oklahoma. Pre-filed Testimony — October 28, 2005 Rebuttal Testimony — March 17, 2006 Oral Testimony — May 9, 2006
New Brunswick Board of Commissioners of Public Utilities (PUB) Ref: 2005-002	New Brunswick Power Distribution Company	Testimony regarding La Capra Associates' three technical audits of the NBP-Disco purchased power budget and variance analyses for FY 2004 – 2006. Oral Testimony — February 14-22, 2006
Connecticut Department of Public Utility Control Docket No. 05-07-14 Phases I and II	Connecticut Energy Advisory Board	Testimony regarding Connecticut's need for electric capacity to meet reliability requirements and to mitigate congestion charges in the wholesale markets. Oral Testimony — February 14-22, 2006 May 1, 2006 June 15, 2006 September 26, 2005
Hawaii Public Utilities Commission Docket No. 03-0372	Hawaii Division of Consumer Advocacy	Testimony regarding competitive bidding rules and integrated resource planning. Oral Testimony — December 12-16, 2005
Oklahoma Corporation Commission Cause No. PUD 2005-151	Oklahoma Industrial Energy Consumers (OIEC)	Testimony regarding resource planning, prudency of generation investment of Oklahoma Gas & Electric Company. Pre-filed Testimony — September 12, 2005 Rebuttal Testimony — September 29, 2005 Oral Testimony — October 18, 2005
Oklahoma Corporation Commission Cause No. PUD 2003-076	Oklahoma Industrial Energy Consumers (OIEC)	Testimony regarding resource planning, prudency of generation investment and fuel and purchased power expenses of Public Service Company of Oklahoma. Pre-filed Testimony — January 4, 2005

Oklahoma Corporation Commission Cause No. PUD 2003-633/4	Oklahoma Industrial Energy Consumers (OIEC)	Testimony regarding power contract proposal for Blue Canyon wind development and avoided costs of Public Service Company of Oklahoma. Pre-filed Testimony August 16, 2004
Civil Litigation Maine Superior Court Docket No. CV-01-24	Central Maine Power Co.	Factual and expert witness in litigation regarding pricing provisions of a purchased power agreement between Central Maine Power and Benton Falls Associates. Deposition Testimony April 28, 2004
Oklahoma Corporation Commission	Oklahoma Attorney General	Testimony regarding power contract proposal for PowerSmith Cogeneration and avoided cost analysis of Oklahoma Gas & Electric Company. Pre-filed Testimony February 18, 2004 Rebuttal Testimony March 16, 2004 Oral Testimony August 4, 2004
Nevada Public Utilities Commission	Nevada Attorney General Bureau of Consumer Protection	Testimony regarding the Nevada Power Company's Integrated Resource Plan and associated financial plan. Pre-filed Testimony September 19, 2003 Oral Testimony October 15, 2003
Massachusetts Energy Facilities Siting Council Docket No. EFSB-02-2	Cape Wind	Testimony regarding economic, reliability and environmental need for power in the Massachusetts and New England power markets regarding the need for new wind power facility. Pre-filed Testimony February 14, 2003 Oral Testimony August 6&7, 2003
Maine State Board of Property Tax Review	United American Hydro	Testimony regarding the Maine and New England power market prices pertaining to the valuation of a hydro-electric power facility in Winslow, Maine. Oral Testimony June18, 2003
Nevada Public Utilities Commission Docket No. 03-1014	Nevada Attorney General Bureau of Consumer Protection	Testimony regarding the prudency of Sierra Pacific Power Company in its purchased power expenses for the period December 2001 through November 2002. Pre-filed Testimony April 25, 2003
Oklahoma Corporation Commission Cause No. PUD 2002-038	Oklahoma Attorney General	Testimony regarding a power contract proposal of Lawton Cogeneration and the pricing analysis of Public Service Company of Oklahoma. Pre-filed Testimony December 16, 2002 Oral Testimony May 22, 2003
Arkansas Public Service Commission	General Staff of the AK Public Service Comm.	Testimony regarding the Development of Competition in Electric Markets and the Impact on Retail Consumers in Arkansas. Pre-filed Testimony September 4, 2001
Arkansas Public Service Commission	General Staff of the AK Public Service Comm.	Testimony regarding the Development of Competition in Electric Markets and the Impact on Retail Consumers in

		Arkansas.	
		Pre-filed Testimony	September 29, 2000
Arkansas Public Service Commission	General Staff of the AK Public Service Comm.	Testimony regarding the establishment of uniform Policies and guidelines for a Standard Service Package.	
		Staff Proposal and Comments	June 13, 2000
		Reply Comments	July 21, 2000
		Sur reply Comments	August 2, 2000
		Oral Testimony	August 8, 2000
		Petition for Rehearing	
		Rebuttal Testimony	November 15, 2000
		Oral Testimony	November 29, 2000
Arkansas Public Service Commission	General Staff of the AK Public Service Comm.	Testimony regarding the determination of the merits of declaring retail billing services competitive effective At the start of retail open access.	
		Oral Testimony	June 27, 2000
		Pre-filed Rebuttal Testimony	June 23, 2000
		Pre-filed Testimony	June 16, 2000
		Oral Testimony	May 10, 2000
Arkansas Public Service Commission	General Staff of the AK Public Service Comm.	Testimony regarding the minimum filing requirements for market power studies to be filed by the Arkansas Electric utilities and affiliated retail companies.	
		Oral Testimony	June 1, 2000
Amer. Arb. Assoc. No. 50T 198 00197-98	Vermont Joint Owners	Testimony regarding economic damages resulting from alleged breach of a long-term purchase power agreement between Hydro-Quebec and Vermont utilities (VJO).	
		Oral Testimony	May 25, 2000
		Pre-filed Rebuttal Testimony	February 10, 2000
		Pre-filed Testimony	August 13, 1999
Rhode Island Energy Facilities Siting Board	Indeck-North Smithfield, L.L.C.	Testimony regarding economic, reliability and environmental need for power in the Rhode Island and New England power markets regarding the need for new, merchant power facility.	
		Pre-filed Testimony	August 16, 1999
		Oral Testimony	August 17, 2000
		Pre-filed Testimony	January 26, 2001
		Oral Testimony	March 23, 2001
Civil Litigation Maine Superior Court Docket No. CV-98-212	Central Maine Power Co.	Factual and expert witness in litigation regarding pricing provisions of a purchased power agreement between Central Maine Power and Regional Waste Systems.	
		Deposition Testimony	May 5, 1999
Connecticut Energy Facilities Siting Council Docket No. 190	PDC – El Paso Meriden LLC	Testimony regarding economic, reliability and environmental need for power in the Connecticut and New England power markets regarding the need for new, merchant power facility.	
		Pre-filed Testimony	January 25, 1999

Rhode Island Energy Facilities Siting Council Docket No. SB-98-1	R. I. Hope Energy, L. P.	Testimony regarding economic, reliability and environmental need for power in the Massachusetts and New England power markets regarding the need for new, merchant power facility. Oral Testimony — November 4, 1998 Pre-filed Testimony — October 30, 1998
Massachusetts Energy Facilities Siting Council Docket No. EFSB-91-101A	Cabot Power Corp.	Testimony regarding economic, reliability and environmental need for power in the Massachusetts and New England power markets regarding the need for new, merchant power facility. Oral Testimony — May 27, 1998 Pre-filed Testimony — August 15, 1997
Massachusetts Energy Facilities Siting Council Docket No. EFSB-97-2	ANP Blackstone Energy	Testimony regarding economic, reliability and environmental need for power in the Massachusetts and New England power markets regarding the need for new, merchant power facility. Oral Testimony — April 6, 1998 Pre-filed Testimony — January 23, 1998
Massachusetts Energy Facilities Siting Council Docket No. EFSB-97-1	ANP Bellingham	Testimony regarding economic, reliability and environmental need for power in the Massachusetts and New England power markets regarding the need for new, merchant power facility. Oral Testimony — February 3, 1998 January 28, 1998
Rhode Island Energy Facilities Siting Board Docket No. SB-97-1	Tiverton Power Associates LP	Testimony regarding economic, reliability and environmental need for power in the Rhode Island and New England power markets regarding the need for new, merchant power facility. Oral Testimony — October 15, 1997 Pre-filed Testimony — October 1, 1997
Maine Public Utilities Commission Docket No. 92-102	Central Maine Power	Testimony regarding CMP's avoided cost methods and practices pertaining to the prudency of power purchase contract decisions with regard to contract awards and contract management. Oral Testimony — July 1993 Deposition Testimony — February 25, 1993 March 1, 1993 Pre-filed Rebuttal Testimony — June 7, 1993 Pre-filed Testimony — June 15, 1992
Maine Public Utilities Commission Docket No. 92-315	Central Maine Power	Testimony regarding CMP's avoided cost methods and practices pertaining to the setting of long-term avoided costs, CMP's Energy Resource Plan, and the relationship of marginal costs of generation to embedded costs. Supplemental Pre-filed Testimony — April 20, 1993 Pre-filed Testimony — February 17, 1993

Maine Public Utilities Commission Docket No. 87-261 Docket No. 88-111	Central Maine Power	Testimony regarding CMP's avoided cost methods and practices pertaining to the setting of long-term avoided costs, CMP's Energy Resource Plan, and the proposal for a 900 MW power Contract with Hydro Quebec. Oral Testimony Summer 1988 Pre-filed Testimony October 31, 1987

II. DOUGLAS A. SMITH

DAYMARK
ENERGY ADVISORS

Douglas A. Smith

Managing Consultant and Treasurer

Doug Smith has over thirteen years of experience in the electric industry, bringing diverse strengths to Daymark's project teams by applying his extensive technical and analytical skills. A business professional with over twenty years of increasing responsibility as a consultant to multiple industries, Mr. Smith has a solid background in analysis, finance and accounting, database and software development, quality assurance, and project management.

Mr. Smith leads the firm's Market Analytics team which is responsible for maintaining Daymark's wholesale power market model and wholesale market outlook, researching energy and capacity markets throughout North America, and producing a variety of forecasts used to provide decision support for client needs including asset valuation, integrated resource planning, non-transmission alternative analysis and other similar projects. He has strong experience in market and power system dispatch analysis, and has been responsible for projecting market valuation, power costs, and emissions impacts for a number of clients.

SELECTED PROFESSIONAL EXPERIENCE

- Led an analysis of wind energy congestion for a potential New England wind and transmission project; reported on potential local and regional congestion
- Led an offshore wind siting feasibility study related to a potential investment in offshore leasing. Investigated interconnection and market risks and opportunities
- Led an analysis of the regional benefits related to a proposed dual-fuel fired peaker plant in New England; assisted the team in analyzing and reporting on emissions impact scenarios, with the plant operating as either an energy unit or a reserve unit; investigated state emissions policies and their potential impact on plant operations
- Led an analysis of a combined proposal for wind energy and transmission in northern New England; assisted team members in understanding the impacts of various quantities of wind energy and the respective transmission needed to deliver wind energy and provided scenario analysis to quantify the range of potential benefits, which resulted in two public reports as components of responses to a regional energy procurement effort
- Managed the creation of a proof of concept model of the Southern Company balancing authority and surrounding areas, including benchmarking to available public data and forecasting of potential future capacity expansion futures
- Assisted in asset valuation modeling work, including modeling of long term energy and capacity values for a number of coal, natural gas and hydro facilities
- As an input to several economic studies for NYSERDA, provided review and analysis of a third-party, long-term forecast of New York's energy and capacity markets
- Managed the review of a large generation owner's price forecasting process; provided recommendations for process improvements designed to more-closely align forecasting efforts with internal requirements and updated and extended the client's New York modeling capabilities

using the AURORA production cost model; recommended key benchmarking tools for evaluation of specific forecasting results

- Assisted in the assessment of a request to the Arkansas Public Service Commission for a declaratory order; the request sought a finding that installation of environmental controls at the Flint Creek power plant was in the public interest
- Assisted in assessing requests to the North Dakota Public Service Commission for Advanced Determinations of Prudence; requests were sought by the Montana Dakota Utilities GT and the Big Stone Air Quality Control System
- Assisted in a review of Entergy Arkansas's strategic planning for post-System Agreement operation on behalf of the General Staff of the Arkansas Public Service Commission
- Assisted a Vermont-based utility in the evaluation of a potential generation purchase; designed an analytical model for use in evaluating potential revenue and cost streams under a variety of scenarios
- Assisted in evaluating non-transmission alternatives (NTAs) as compared to a set of proposed transmission upgrades in Vermont; assisted in the development of an economic scorecard designed to facilitate the comparison of transmission and non-transmission solutions on equal footing and compared potential rate impacts of the proposed solutions
- Assisted in evaluating non-transmission alternatives (NTAs) as compared to a set of proposed transmission upgrades in Maine; evaluated the economics of transmission and non-transmission solutions and leveraged market simulation models to estimate the impact of solutions on energy clearing prices in Maine and in New England
- On behalf of Vermont-based utility, developed and analyzed non-transmission alternatives (NTAs) to a set of proposed transmission upgrades that would impact the distribution-level supply system; developed an economic tool to evaluate the cost of operating "pre-contingency" generation options
- Analyzes budgetary and other cost-related data on behalf of the National Railroad Passenger Corporation (Amtrak); interacts with the client on a monthly basis to provide analysis of power cost drivers, track monthly power costs, and deliver other accounting and electric consulting services; provides assistance in periodic power procurement activities
- Assisted in planning, managing, and performing an audit of actual and hypothetical purchased power costs for a Michigan utility; issues included market valuation of potential sales, proper treatment of a pumped storage unit, and validation of commitment/dispatch logic; this project also involved a process audit and the review of large volumes of data involved in determining hypothetical system costs
- Assisted in maintaining an Allocated Cost of Service model, including modifying allocators and introducing new methodology
- Researched issues related to state, regional, and Federal environmental regulations and their impacts on energy generation; modeled environmental variables including current SO_2, NO_X and CO_2 rates and allowance prices, emission control technologies, and likely future changes
- Participated in developing revenue projections for valuation of power plants

PUBLICATIONS

MCPC Project Benefits; Quantitative and Qualitative Benefits, Confidential Report prepared for Central Maine Power regarding the benefits of the Maine Clean Power Connection, a 345 kV transmission expansion accompanied by 1100 MW of wind energy project development offered in the Massachusetts RFP for Clean Energy Resources, July 27, 2017. Lead Analyst and Contributing Author.

NECEC Project Benefits; Quantitative and Qualitative Benefits, Confidential Report prepared for Central Maine Power and H.Q. Energy Services regarding the benefits of the New England Clean Energy Connection, 1200 MW HVDC transmission expansion accompanied by 1090 MW of hydropower and wind energy project development offered in the Massachusetts RFP for Clean Energy Resources, July 27, 2017. Lead Analyst and Contributing Author.

MREI Project Benefits; Direct, Indirect, Qualitative and Other Benefits, prepared for Central Maine Power Company and Emera Maine regarding the benefits of the Maine Renewable Energy Initiative, a 345 kV transmission expansion accompanied by 1200 MW of wind energy project development, January 28, 2016. Lead Analyst and Contributing Author.

MCPC Project Benefits; Direct, Indirect, Qualitative and Other Benefits", prepared for Central Maine Power Company regarding the benefits of the Maine Clean Power Connection, a 345 kV transmission expansion accompanied by nearly 600 MW of wind energy project development, January 28, 2016. Lead Analyst and Contributing Author.

EMPLOYMENT HISTORY

Daymark Energy Advisors Inc.	Boston, MA
Treasurer	2016 – Present
Managing Consultant	2017 – Present
Senior Consultant	2008 – 2017
Analyst	2004 – 2008
The Sports Authority	Ft. Lauderdale, FL
Senior POS/EDP Programmer/Analyst	2002 – 2004
University of Colorado	Boulder, CO
*Instructor, Oracle SQL*Plus Class*	2001 – 2001
SHL USA Inc.	Boulder, CO
Software Engineer	2000 – 2001
Strategic Technologies Group	Boulder, CO
Senior Consultant	1995 – 2000

EDUCATION

Syracuse University	Syracuse, NY
B.S., Accounting, Summa Cum Laude	1991