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Final Report

83C Round III Quantitative Evaluation Report

Long-term Contracts for Offshore Wind Energy Projects Pursuant to Section 83C of Chapter 169 of the Acts of 2008

Prepared for:

Eversource Energy
National Grid
Unitil Corporation

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DISCLAIMER

83C Part III Quantitative Evaluation Report has been prepared by Tabors Caramanis Rudkevich, INC (TCR) for the Massachusetts Electric Distribution Companies (EDCs), Eversource Energy, National Grid US and Unitil for the sole purpose of providing the quantitative analyses to allow the EDCs to evaluate the proposals that they receive in response to the 83C Round III RFPs. The information provided herein deals with the analysis, methodology and results of the proposal quantitative evaluations. Any other use of the materials without the explicit permission of the EDCs is strictly prohibited.

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Section 1. Summary and Overview

1.1: Background

The Massachusetts ("MA") electric distribution companies ("EDCs") issued a Request for Proposals ("RFP") on May 7th 2021 for long term contracts from offshore wind energy projects. The EDCs solicited bids ("Proposals") for projects ("Projects") providing such supplies of offshore wind energy and Renewable Energy Certificates ("RECs") to comply with Section 83C of the Massachusetts Green Communities Act. This RFP ("83C Round III" or "83C III") is a third round of procurement totaling a maximum of 1,600 megawatts ("MW") of offshore wind. The first two rounds of this procurement ("83C I" and "83C II") resulted in the Massachusetts EDCs entering into long term contracts for 800 MW offshore wind each through a similar RFP process initiated in June 2017 and May 2019 respectively. The Massachusetts EDCs selected Tabors Caramanis Rudkevich ("TCR") as Evaluation Team Consultant to help them evaluate certain costs and benefits[1] of the proposals received in response to the RFP. This report summarizes the analyses TCR prepared to evaluate such costs and benefits, and the results of those evaluations.

The 83C III RFP required bidders to submit proposals for at least 200 MW and up to 1,600 MW of generation capacity[2].

The 83C III RFP Evaluation Team ("Evaluation Team") reviewed and evaluated the Project bids using a process described in testimony sponsored by the EDCs in this proceeding. As part of this process, TCR performed the Stage Two Quantitative Analysis of each Proposal by creating a scenario or "case" for each Proposal ("Proposal Case") and a common "counterfactual" case ("83C III Base Case") which provides projections under a future in which the EDCs do not acquire wind energy under long-term contracts from any of the Proposals received in response to the 83C III RFP. TCR evaluated the costs and benefits of each Proposal Case using inputs from that Proposal and results from modeling the operation of the New England and New York energy markets assuming the specific Proposal being modeled is chosen, as well as results from the modeling of the 83C III Base Case.

During Stage Three of the evaluations, the Evaluation Team combined Proposals into Portfolios which were then evaluated by TCR in a manner consistent with Stage Two Proposals. TCR created a case for each Portfolio selected by the Evaluation Team ("Portfolio Case") and evaluated the costs and benefits of each Portfolio Case using inputs from the component Proposals and results from modeling the operation of the New England and New York energy markets assuming the specific Portfolio being modeled is chosen, as well as results from the modeling of the 83C III Base Case. TCR also performed certain sensitivity and scenario cases requested by the Evaluation Team to facilitate Stage Three of the evaluation.

1 The costs and benefits TCR analyzed were a subset of the overall costs and benefits associated with the 83C III RFP bids. Costs and benefits considered less amenable to quantification were analyzed in the Qualitative Analysis portions of the evaluation process. In this report, we use "costs and benefits" and similar terms to refer to the subset of costs and benefits TCR quantified using its tools and methods.

2 Bidders were allowed to propose minor variations in proposed contract size based on expected turbine size and potential changes to expected turbine size.

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Appendix A summarizes the results of TCR's Stage Two Quantitative Analyses of each Proposal Case, the quantitative scores based on those results, the qualitative scores developed by the 83C III Qualitative Team, and the ranking of each Proposal based on the total of the quantitative and qualitative scores.

Appendix B summarizes the results of TCR's Stage Three Quantitative Analyses of Portfolio Cases, the quantitative scores based on those results, the qualitative scores calculated by TCR based on the Stage Two qualitative scores of the component Proposals, and the ranking of each Portfolio based on the total of the quantitative and qualitative scores[3]. Appendix B also summarizes the sensitivity and scenario cases TCR provided for the Stage Three evaluation. The results of the Stage Three Analysis are compared against and presented alongside Stage Two Proposals.[4]

1.2: Analytical Approach

The TCR Quantitative Analyses used metrics for the two categories of costs and benefits specified in the RFP, *i.e.* Direct Contract Costs and Benefits ("Direct Costs and Benefits") and Other Costs and Benefits to Retail Consumers ("Indirect Costs and Benefits").

- TCR developed values for the Direct Cost and Benefit metrics of each Proposal/Portfolio using data from the Proposals themselves, from the outputs of TCR's Proposal/Portfolio Case simulation modeling and from the Proposal/Portfolio Case Greenhouse Gas ("GHG") Inventory calculation carried out in the Quantitative Workbook of each Proposal/Portfolio Case.[5]
- TCR developed values for the Indirect Cost and Benefit metrics of each Proposal/Portfolio by comparing outputs of its simulation modeling of each Proposal/Portfolio Case to the outputs of its simulation modeling of the 83C III Base Case, as well as from the comparison of their respective GHG Inventory calculations in its Quantitative Workbook for each Proposal/Portfolio Case

TCR developed values for each of these metrics in 2021 constant dollars ("2021$") for each Proposal/Portfolio by year over a forecast evaluation period of 2025 to 2050[6] ("evaluation period" or "valuation horizon"). **Section 2** of this Report describes those metrics.

3 TCR produced two sets of scoring and rankings for the Stage Two and Stage Three evaluations corresponding with two sets of scores provided by the 83C III Qualitative Team to TCR. The first set of rankings is identified as 'NG/Unitil/DOER' reflecting the qualitative scores awarded by members of the Evaluation Team except Eversource, and a second set of rankings identified as 'ES' reflecting the qualitative scores awarded by Eversource.

4 Certain Stage Two Proposals and Stage Three Portfolios are reported twice using an alternative 'adjusted' quantitative scoring metric. These are sensitivity cases whose objective is to reflect the impacts of potential modifications of 83C II contracts which could impact the bid being selected. For additional details, refer to Appendix D.

5 The DOER provided the general principles and methodology for calculating the value of the incremental contribution ($/MWh) to GWSA compliance. TCR implemented the methodology, and, as specified in the 83C III quantitative protocol, used 17.76 2021$/MWh as the unit value. This value is the $16.51/MWh unit value established in the 83D evaluation to calculate the GWSA compliance value of this contribution, adjusted for inflation. National Grid's concerns with the methodology and compliance value used in the calculation of the GWSA compliance contribution benefits by DOER, Eversource, and Unitil were set out in detail in its response to Information Request DPU-5-12 in the 83C Round 1 solicitation, Joint Petition of NSTAR Electric Company et al., D.P.U. 18-76/77/78, and in its response to Information Request DPU-2-14 in the 83D solicitation, Joint Petition of NSTAR Electric Company et al., D.P.U. 18-64/65/66. Despite these concerns, National Grid does not intend to sponsor a separate, alternative GWSA net benefit calculation in the current solicitation. This is because National Grid does not believe that the differences between its own version of the GWSA calculation (described in the Information Request responses cited above) and the DOER/Eversource/Unitil version will be material under the particular facts and circumstances of the current 83C Round 3 solicitation.

6 This evaluation period ensures that all proposal and proxy units are evaluated over the entirety of their respective PPA periods.

1.3: Evaluation Models & Workbooks

Section 3 of this Report describes TCR's simulation of the 83C III Base Case as well as the Proposal/Portfolio Cases. Appendix E provides 83C III Base Case results in detail. Appendix F provides detailed descriptions of the assumptions TCR used to model the 83C III Base Case and the Proposal/Portfolio Cases, as well as the ENELYTIX® platform used to do that simulation modeling. **Section 4** describes the Quantitative Workbook for each Proposal/Portfolio Case.

As the EDC testimony describes, bid scoring was based on a 100-point scale under which a Proposal Case could receive a maximum of 70 points based upon the results of its Quantitative Analysis performed by TCR and a maximum of 30 points based upon the results of a separate Qualitative Analysis performed by a separate set of members of the Evaluation Team ("83C III Qualitative Team"). See Appendix C.1 for the Quantitative Protocol describing the point allocation/scaling methodology. TCR developed the Quantitative Analysis scores assigned to each Proposal Case based upon the results of the analyses described in this Report. TCR added these Quantitative Analysis scores to the Qualitative Analysis scores provided to it by the 83C III Qualitative Team to calculate the total score of each Proposal Case.[7]

TCR then ranked each Proposal/Portfolio Case from high to low according to the total scores. **Section 5** describes this scoring and ranking.

Discussions in the subsequent sections describe TCR's process for evaluating Proposal Cases in Stage Two. Unless stated otherwise, it should be noted that identical processes were used to evaluate Portfolios during the Stage Three analysis.

7 For Portfolio Cases, TCR calculated qualitative scores based on the capacity weighted average of the quantitative scores of its component Proposals.

Section 2.
Evaluation Costs and Benefits

This section summarizes the analytical approach and metrics TCR used to measure each category of costs and benefits and to develop values for each of those metrics.

The 83C III RFP process evaluated two quantitative categories of costs and benefits - Direct Contract Costs and Benefits ("Direct Costs and Benefits") and Other Costs and Benefits to Retail Consumers ("Indirect Costs and Benefits"). Prior to opening the 83C III bids, the Evaluation Team developed a Protocol for 83C III Quantitative Metric Calculations, Stage 2 ("83C III Quantitative Protocol"). That protocol, provided in Appendix C.1, specifies the analytical approach and metrics to be used for the quantitative evaluation of the direct and indirect costs and benefits. Additional complexities were identified after opening of bids that required adjustments to the evaluation protocol. These adjustments are discussed in an addendum to the 83C III Quantitative Protocol provided in Appendix C.2.

Finally, case specific modifications to modeling inputs and the evaluation process were necessary to ensure appropriate representations of the bidders' proposals as well as to ensure a fair evaluation of bids. These modifications are described in more detail, along with identifying the Proposals they apply to, in Appendix D.

2.1: Analytical Approaches to Quantitative Evaluation of Proposal Cases[8]

The 83C III Quantitative Protocol, specifies that each Proposal *"will assume the EDCs ultimately acquire 1,600 MW of new offshore capacity by 1/1/ 2030 consisting of the offshore wind capacity from the Project being evaluated and, if the Project being analyzed is less than 1,600 MW, additional OSW capacity is assumed to be available from Proxy Units representing offshore wind capacity procured in a subsequent 83C solicitation."* That specification reflects the fact that an individual bidder responding to the 83C III RFP had the option to submit multiple Proposals, with capacities ranging in size from 200 MW to 1,600 MW. The Evaluation Team concluded that the most accurate, realistic, and fair way to compare Proposals of different sizes was to assume a common end-state size, in this case 1,600 MW that would be achieved by 2030.

TCR thus evaluated each Proposal as being part of a total of 1,600 MW of new, additional offshore generating capacity and associated transmission facilities to be achieved by 2030. Where Projects bid were less than 1,600 MW, proxy units were added to supplement the bid capacity to achieve a total of 1,600 MW.

TCR used ENELYTIX® to model each Proposal Case as having a total of 1,600 MW of new offshore generating capacity built out in multiple "tranches" or "Phases" of offshore generation capacity, each with a different commercial operation date ("COD").

8 TCR applied the same analytical and modeling approach to evaluating Portfolio Cases during Stage Three evaluations. For this and subsequent sections of the report, the term Proposal Case can be used interchangeably with Portfolio Case which is simply an aggregation of Proposals.

The timing and capacity of the Project units were assumed to be as bid, and for the proxy unit were based on a defined set of rules described in the 83C III Quantitative Protocol that ensured 1,600 MW of additional offshore wind by 1/1/2030. Proxy unit costs were based on the actual cost of the specific Proposal to which proxy unit was being added.

2.2: Metrics Used in Quantitative Evaluation of Proposal Cases

The 83C III Quantitative Protocol, specifies the *"…core quantitative measure of comparison*" as *"…the levelized net unit benefit per MWh of the project expressed in 2021 dollars"*. For each Proposal Case, TCR developed the value for each component direct and indirect metric described in this section, by year, over the evaluation period in 2021$. It then calculated the present value for each metric using a real discount rate of 4.73%. The real discount rate was based on the EDCs' load-weighted average cost of capital of 6.82% (nominal) and an assumed inflation rate of 2.00%. Finally, TCR calculated a levelized unit value ($/MWh) for each metric as the present value divided by the present value of the annual energy from the Proposal Case.

2.2.1: Direct Costs and Benefits

TCR measured the Direct Costs and Benefits of each Proposal Case[9] by calculating the values of each of the following metrics:

i. **Total Direct Costs** include the Direct Cost of Energy, the Direct Cost of Renewable Portfolio Standard ("RPS") Class 1 eligible RECs, and the Remuneration Cost. The Direct Cost of Energy was calculated from the Proposal price for energy multiplied by the annual quantity of delivered energy for each year over the proposed contract term. The Direct Cost of RPS Class 1 eligible RECs was calculated from the Proposal price for RECs multiplied by the annual quantity of RECs for each year over the proposed contract term. The Remuneration cost was calculated as a fixed percentage[10] of the Direct cost of Energy plus the Direct Cost of RPS Class 1 eligible RECs. The resulting levelized unit value for Total Direct Costs of the Proposal is reported in columns H and I of Appendix A.

ii. **Total Direct Benefits** include the Direct Benefit of Energy, RECs, MA Clean Energy Certificates ("CECs"), and MA Clean Peak Energy Certificates ("CPECs"). The Direct Energy Benefit is the market value of the energy deliveries from the Project over the proposed contract term, based upon the forecast market energy prices at the delivery point under the Proposal Case. The Direct Benefit of RECs and CECs is the avoided cost of using these products from the Proposal Case to meet RPS + CES requirements[11], valued at the Base Case market prices of RECs and CECs, plus the forecast market value of any RECs and CEC delivered to the EDCs that are surplus to RPS + CES requirements. The Direct Benefit of CPECs is the benefit of the Proposal's contribution to the MA clean peak standard, calculated using the peak periods and credit multipliers described in the CPS regulations and valued at the price of alternative compliance payments.

9 The costs and benefits of Proposals whose projects were less than 800 MW include costs and benefits of the proxy unit.

10 TCR calculated the remuneration costs as being 2.75% of the direct costs based upon the 83C statute.

11 RECs from the Project automatically qualify as CECs under the MA CES. Because of overlaps in MA RPS and CES eligibility, CES requirements are modeled as being incremental to RPS, and eligible units only receiving credit once.

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The resulting Net Direct Benefit (Cost) is the sum of the above Direct Costs and Direct Benefits. The levelized unit values of the Net Direct Benefit (Cost) are reported in column K of Appendix A for the Proposals.

2.2.2: Indirect Costs and Benefits

TCR measured the Indirect Benefits of each Proposal Case by calculating the values of each of the metrics described below.[12]

i. **Indirect Energy Price Benefits** are the savings over the evaluation period from changes to wholesale energy market costs paid by EDC load in Massachusetts, i.e., from changes to Locational Marginal Prices ("LMP") in Massachusetts in the Proposal Case relative to energy market costs paid by EDC load in Massachusetts in the 83C III Base Case. This metric first calculates the gross annual savings associated with Massachusetts EDCs retail load i.e., net energy for Massachusetts load less the load served by Municipal Light Plants ("MLPs"). It then calculates the change in aggregate market value of energy from all existing EDC long-term contracts in the 83C III Proposal Case being analyzed compared to the 83C III Base Case. Finally, the metric calculates the net impact as the gross savings on EDC retail load less the change in revenues the EDCs derive from selling energy from previously-signed EDC long-term contracts.

ii. **Indirect REC Price Benefits** are the savings over the evaluation period from changes to the costs paid by Massachusetts EDCs for Class 1 RECs based on expected market prices in the Proposal Case relative to the 83C III Base Case. This metric calculates the savings associated with RECs obtained by the Massachusetts EDCs to meet the state RPS requirements incremental to the RECs delivered by the Proposal and through existing long-term contracts.

iii. **The Global Warming Solutions Act ("GWSA")** compliance Benefit is the value of the Proposal's incremental contribution towards meeting the Massachusetts GWSA, i.e., incremental to compliance with the RPS and the CES in the Proposal Case relative to the 83C III Base Case.

iv. **Impact of Contribution to Reducing Winter Electricity Price Spikes**. This metric measures the incremental benefit[13] from Proposal energy market revenues under conditions of extreme high and low winter gas prices. The metric relies on two separate modeling scenarios of each Proposal Case for a specified year (2030/2031) wherein the fuel prices in the months of December, January, and February ("winter period") are adjusted to 15-year historic high and historic low prices respectively. The resulting net percentage change in annual revenues between the two scenarios is applied to the Proposal Case assuming a 1 in 20-year probability of occurrence, i.e., occurring once during the evaluation period.

The resulting Total Indirect Benefit is the sum of the above Indirect Benefits. The levelized unit values of the Total Indirect Benefit for each Proposal are reported in column L of Appendix A.

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12 Like 83C I and 83C II, the 83C III Quantitative protocol does not include a Capacity Price Indirect Benefit metric. This is based upon a Steering Committee determination that projections for this metric would not be reliable. Capacity market price changes resulting from any particular resource addition are difficult to forecast with precision and can be highly dependent on other factors and assumptions The Steering Committee determined that the most reliable and conservative approach would be to exclude capacity benefits from the analysis of all Proposals.

13 This benefit is not captured in the remaining direct and indirect benefits since those metrics are developed under projections assuming normal weather conditions

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2.2.3: Net Benefit (Cost)

The Net Benefit (Cost) of a Proposal is the sum of its Total Direct Benefit (Cost) and its Total Indirect Benefit (Cost).. The levelized unit value of this metric is the core measure for comparison under the 83C III Quantitative Protocol. Appendix A column M reports this value, in $/MWh.

TCR also calculated the Net Benefit (Cost) in absolute terms ($). This value equals the present value of the Total Direct Benefits and Total Indirect Benefits less the present value of the Total Direct Costs. Appendix A column N reports this metric.

2.2.4: Quantitative Workbooks

TCR developed the values of these metrics in a Quantitative Workbook for each Proposal and Portfolio.

- TCR developed values for the Direct Cost and Benefit metrics of each Proposal Case from the bids submitted for each Proposal, from the outputs of its simulation modeling of each Proposal Case, outputs from its simulation modeling of the 83C III Base Case, as well as from its quantitative evaluation workbook for each Proposal Case.
- TCR developed values for the Indirect Cost and Benefit metrics of each Proposal Case by comparing outputs of its simulation modeling of each Proposal Case to the outputs of its simulation modeling of the 83C III Base Case, as well as from its quantitative evaluation workbook for each Proposal Case.

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Section 3. Market Simulations – 83C III Base Case and Proposal Cases

TCR developed values for many of the metrics used in the calculations of Direct Costs and Benefits as well as Indirect Costs and Benefits from the outputs of its simulation modeling of the 83C III Base Case and each Proposal Case. This section describes the basic differences between the 83C III Base Case and the Proposal Cases. It then describes the ENELYTIX® platform TCR used to model each of those Cases and the major input assumptions TCR used in that modeling.

3.1: 83C III Base Case and Proposal Cases

The 83C III Base Case provides a "but for" or "counterfactual" projection of carbon emissions as well as energy costs associated with Massachusetts electricity consumption under a future in which the EDCs do not acquire wind energy under long-term contracts from any of the Proposals received in response to the 83C III RFP.[14]

Each Proposal Case provides a projection of carbon emissions and costs associated with Massachusetts electricity consumption under a future in which the EDCs acquire the wind energy bid by that Proposal (and a proxy unit, if needed) under a long-term contract. TCR used the results from each Proposal Case as well as certain inputs from the 83C III Base Case to measure the Direct Costs and Benefits of that Proposal described in Section 2, *i.e.*, these Cases provide the projections of carbon emissions and costs with the Proposal in service.

TCR reflected the difference between the 83C III Base Case and each Proposal Case in its modeling by using inputs corresponding to each case for generation capacity additions and for transmission system upgrades/changes where these were affected by such generation capacity additions. Subsection 3.3 summarizes each major category of input assumptions TCR used in its modeling and describes the differences in input assumptions between the 83C III Base Case and each Proposal Case. Appendix F provides detailed descriptions of the assumptions TCR used to model the 83C III Base Case and the Proposal Cases, as well as of the ENELYTIX® platform TCR used for its simulation modeling.

The differences in these input assumptions cause the model to produce differences in results between the Base Case and each Proposal Case. Appendix E provides key results from the ENELYTIX® modeling of the 83C III Base Case.

3.2: ENELYTIX® Simulation Model

TCR used the ENELYTIX® computer simulation software tool to simulate the operation of the New England and New York wholesale markets for energy and ancillary services and RECs under the 83C III Base Case and for each Proposal Case. ENELYTIX® develops internally consistent, detailed projections of prices in each of those markets as well as of the key physical parameters underlying those prices

14 The 83C III Base Case is not a plan for the Massachusetts electric sector and should not be viewed as such. TCR used the results from the 83C III Base Case as a common reference point against which to measure the Indirect Costs and Benefits of each Proposal described in Section 2, *i.e.*, the 83C III Base Case provides the projections of carbon emissions and costs without any of the Proposals in service.

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such as capacity additions and retirements, energy generation by source, carbon emissions and fuel burn. TCR conducted a separate ENELYTIX® run for the Base Case and for each Proposal Case being analyzed.

ENELYTIX® developed its projections through the interaction of the Capacity Expansion module and the Energy and Ancillary Services ("E&AS") module.[15]

- The Capacity Expansion module determines an optimal electric system expansion in New England and New York over a long-term planning horizon. Its objective function is to minimize the net present value of the total cost, *i.e.*, capital, fuel and operating, of the generation fleet serving the wholesale market within the ISO-NE and NYISO **[?]** electrical footprint subject to resource adequacy, operational and environmental constraints. Resource adequacy constraints are specified in terms of installed capacity requirements ("ICR") for the ISO-NE system as whole and for reliability zones within ISO-NE. Resource adequacy constraints were also imposed for NYISO and its sub-areas. Environmental constraints include requirements for state-by-state procurement of electric energy generated by renewable resources, as well as state and regional emissions limits. The module represents each state's year-by-year Class 1 RPS requirements, Massachusetts CES requirements, state-specific RPS resource eligibility, limitations on REC banking and borrowing, and alternative compliance payment ("ACP") prices. The NYISO model includes the CLCPA Act16 among other mandated clean energy targets.
- The Energy and Ancillary Services ("E&AS") module simulates the Day-Ahead and Real-Time market operations within the footprint of the ISO-NE and New York Independent System Operator ("NYISO") power systems and markets. This module implements hourly chronological simulations of the Security Constrained Unit Commitment ("SCUC") and Economic Dispatch ("SCED") processes, as well as the structure of the ancillary services in ISO-NE and NYISO markets.

The two modules use the Power System Optimizer ("PSO") market simulator developed by Polaris Systems Optimization, Inc.[17] In addition the two modules rely on data obtained from ISO-NE and NYISO including the economic and operational characteristics of existing generating units, representation of the electric transmission system, and projection of future electricity demand.

3.3: Major Input Assumptions Used to Model 83C III Base and Proposal Cases

TCR used ten major categories of input assumptions[18] to model the 83C III Base Case and each of the Proposal Cases in ENELYTIX®. They were Generating Unit Capacity Additions, Transmission Topology, Load Forecast, Installed Capacity Requirements, RPS Requirements, Massachusetts CES and annual cap on Carbon Emissions, Emission Allowance Prices, Generating Unit Retirements, Generating Unit Operational Characteristics and Fuel Prices. Of those, the only three categories in which there were

15 TCR did not use the Forward Capacity Market module of ENELYTIX because the 83C III Quantitative Protocol did not require a projection of capacity prices.

16 Climate Leadership and Community Protection Act (https://www.nyserda.ny.gov/All-Programs/CLCPA)

17 www.psopt.com.

18 TCR uses the term 'Assumptions' to refer to inputs to the modeling process that are exogenous to the model, and often calculated from data available from sources such as ISO-NE, EIA's Annual Energy Outlook or other proprietary datasets such as S&P Market Intelligence Platform.

input assumption differences between the 83C III Base Case and each Proposal Case were Generating Unit Capacity Additions, Generating Unit Retirements and Transmission Topology.

This subsection summarizes each of the major categories of input assumptions TCR used in modeling ISO-NE and describes the differences in those input assumptions between the 83C III Base Case and each Proposal Case. TCR used the input assumptions in the remaining seven categories to model both the 83C III Base Case and each of the Proposal Cases. Appendix F provides detailed descriptions of the assumptions for ISO-NE and for the NYISO that TCR used to model the 83C III Base Case and the Proposal Cases. The following sub-section will discuss categories of assumptions focusing on the ISO-NE model.

3.3.1: ISO-NE Modeling Input Assumption Categories with differences between the 83C III Base Case and each Proposal Case

Three categories of modeling input assumptions that were different between the 83C III Base Case and each Proposal Case were Generating Unit Capacity Additions, Generating Unit retirements, and Transmission.

Generating Unit Capacity Additions. This category consists of three groups of resources.

Existing & Scheduled capacity additions are the generating resources input to ENELYTIX® assumed to be in-service during the evaluation period based on external source materials and inputs from the EDCs. These resources are common to the 83C III Base Case and all Proposal Cases. These include:

- Existing generating units listed in the 2021 ISO New England Forecast Report of Capacity, Energy, Loads, and Transmission (“CELT Report”);
- Projects that had cleared the most recent Forward Capacity Auction (FCA15);
- Distributed photovoltaic (PV) capacity at levels in the ISO-NE’s Final 2021 PV Forecast through 2030 and thereafter at levels extrapolated from the ISO-NE PV Forecast[19] which includes PV installed under the Solar Massachusetts Renewable Target (SMART) Program;
- Renewable generation projects that either have existing long-term contracts with the EDCs, or that have been selected to negotiate contracts with the EDCs as of June 15, 2021.[20] These include, but are not limited to projects from the MA 83D and previous MA 83C solicitations.

Proposal capacity additions are the as-bid Project and assumed Proxy offshore wind units that are specific to the Proposal being evaluated and included in each of the respective Proposal Case models.[21] The performance and costs of these units are based on the bid documents and Proxy unit assumptions that are detailed in the 83C III Quantitative Protocol. The 83C III Base Case does not include any proposal additions.

Model selected capacity additions are renewable and fossil resources that ENELYTIX® has the option to add at least cost during the study horizon, as determined by its internal calculations, to meet resource adequacy, energy and environmental constraints existing within the simulation

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19 ISO New England Final 2021 PV Forecast, March 22, 2021.

20 Refer to Appendix E for a list of renewable projects included in the 83C III Base Case and all Proposal Cases

21 Some proposal cases also proposed changes to previously contracted units. Such changes are contingent upon the Proposal being selected and therefore not included in the 83CIII Base Case.

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model over the study time period. ENELYTIX® evaluates the economics of each of these possible resources with the assumption that they would be developed and financed on a merchant basis, *i.e.* without long-term purchase power agreements. Even if these resources were assumed to have long-term power sales agreements, the expectation is that the pricing terms of such agreements would reflect similar future economic fundamentals.

Due to similarity in the schedule of offshore wind additions across Proposal Cases (1,600 MW by 2030), and to ensure a consistent comparative evaluation of proposals, all Proposal Cases share a common set of model selected capacity additions that are developed independently from the model selected capacity additions in the 83C III Base Case.

Proposal Case model additions are a result of a 'generic' capacity expansion model whose details can be found as an attachment to the 83C III Quantitative Protocol.

Generating Unit Retirements. This category consists of two groups of assumptions.

Scheduled retirements are the specific generating capacity units input to ENELYTIX® as retiring prior to, or during, the evaluation period. These are the generating units that are scheduled to have retired prior to the beginning of the evaluation period (January 2025) plus the ISO-NE approved scheduled retirements as of June 2021 over the evaluation period.

Model Selected retirements are existing generating units that are retired by ENELYTIX® over the study period based upon their economic viability. ENELYTIX® determines, within the simulation, whether it is cost efficient to keep an existing unit online, to retire the unit, or to replace it with a more efficient unit or with a resource that is needed to meet environmental constraints.

Similar to model selected additions, Proposal Cases share a common set of model selected retirements. Different from additions, these retirements are incremental to retirements in the 83C III Base Case, i.e. retirements from the 83C III Base Case capacity expansion model are held in all model runs.

Proposal Case model selected retirements are a result of a 'generic' capacity expansion model whose details can be found as an attachment to the 83C III Quantitative Protocol.

Transmission. ENELYTIX® provides a detailed representation of the transmission topology and electric characteristics of transmission facilities within ISO-NE and the NYISO. The Evaluation Team and TCR worked together to ensure that the ENELYTIX® model correctly reflected the transmission upgrades associated with each Proposal that were not required for the 83C III Base Case. These included transmission topology and contingency sets for additional contingency constraints that might be affected by power injections from 83C III Proposals.

Aside from those differences, the remaining transmission input assumptions were common to the 83C III Base Case and each Proposal Case over the evaluation horizon. ENELYTIX® modeled the ISO-NE transmission system based on the 2025 summer peak power flow case obtained from ISO-NE and the NYISO system based on the 2024 summer peak power flow case obtained from NYISO. For the 83C III Base Case, and each Proposal Case, TCR worked with the Evaluation Team to identify the relevant transmission constraints to monitor. These included all major ISO-NE interfaces and frequently binding constraints assembled by the Evaluation Team using historical data through June 2021, transmission changes associated with large clean energy projects procured through recent RFP processes, and contingency analyses performed by the Evaluation Team and TCR.

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3.3.2: ISO-NE Modeling Input Assumption Categories with no differences between the 83C III Base Case and each Proposal Case

The remaining seven categories of modeling input assumptions that are common to the Base Case and each Proposal Case are Load Forecast, Installed Capacity Requirements, RPS Requirements, Massachusetts CES and cap on Carbon Emissions, Emission Allowance Prices, Generating Unit Operational Characteristics and Fuel Prices.

Load Forecasts. The load forecast inputs to ENELYTIX® are annual energy and peak load before ("Gross") and after the impacts of reductions due to passive demand response ("PDR"), *i.e.* "Gross less PDR". TCR drew these forecasts through 2030 from the ISO-NE 2021 CELT Report. It developed the forecasts for 2031 through 2050 through separate extrapolations of the Gross and PDR components. TCR also developed a forecast of energy requirements net of the impacts of reductions from behind the meter photovoltaic generation ("BTMPV" or "BMPV"). This forecast, which corresponds to the obligation for retail metered load, is referred to by ISO-NE as Net Energy Load ("NEL") or as "Gross less PV less PDR". TCR used this forecast to estimate annual state RPS obligations and MA CES obligations, both of which are inputs to ENELYTIX®. In order to simulate the ISO-NE market on an hourly basis, TCR developed hourly load forecasts for each ISO-NE zone. It developed these based upon its forecasts of annual energy and summer/winter peaks and on 2012 historical load shapes to be consistent with calendar 2012 NREL wind generation profiles, the most recent detailed data available from NREL for New England.

Installed Capacity Requirements. ICR forecast inputs to ENELYTIX® include the system-wide requirement as well as local sourcing requirements ("LSR") for import constrained zones. TCR developed its forecasts of these requirements based on its analyses of ISO-NE studies[22]. The forecast of system-wide ICR assumes that import capacity under the existing supply agreement with Hydro Quebec and imports from other external control areas including New York, New Brunswick, and Highgate will remain at the level identified in the most recent ISO-NE capacity auction.

RPS Requirements. ENELYTIX® models the Class 1 RPS requirements of each New England state except Vermont, which does not have an equivalent Class 1 RPS requirement. The RPS requirement input to ENELYTIX® for each state equals the forecast load of Load Serving Entities ("LSEs") obligated to comply with that state's RPS multiplied by that state's annual Class 1 RPS percentage target. The forecast load of LSEs is the forecast Gross less PV less PDR load for each state reduced by the load exempt from the RPS in that state. Additional RPS inputs to ENELYTIX® are state-specific resource eligibility, limitations on certificate banking and borrowing, and ACP prices.

Massachusetts CES and Cap on Carbon Emissions. ENELYTIX® models regulation 310 CMR 7.74, a cap on carbon emissions from electric generating units ("EGU") located in Massachusetts and regulation 310 CMR 7.75, the CES. The CES requirement input to ENELYTIX® equals the forecast load of LSEs obligated to comply with the CES multiplied by the Massachusetts annual CES percentage target.

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22 ISO-NE History of historical ICR and related values (https://www.iso-ne.com/static-assets/documents/2016/12/summary_of_historical_icr_values.xlsx), ISO-NE Regional System Plan (https://www.iso-ne.com/system-planning/system-plans-studies/rsp), ISO-NE Calculation of ICR and local resource requirements (https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/installed-capacity-requirement)

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Emission Allowance Prices. TCR used the CO_2 allowance price assumptions based on Regional Greenhouse Gas Initiative (RGGI) projections from WoodMac's 2021 North American gas forecasts.[23] TCR developed its NOx and SO_2 allowance price assumptions for NYISO based on emission limits under the Federal Cross State Air Pollution Rule ("CSAPR").[24] Appendix F describes the additional TCR allowance price assumptions for NYISO

Generating Unit Operational Characteristics. TCR developed assumptions for the key physical and operating cost parameters of all the types of generating units and resources that ENELYTIX® models. These include thermal units, nuclear units, hydro, pumped storage hydro, wind and solar PV.

Fuel Prices. TCR developed forecasts of monthly spot gas prices for each gas-fired unit in New England based upon the spot prices at the market hub which serves the unit. The four relevant hubs are Algonquin, Tennessee Zone 6, Tennessee Dracut and Iroquois Zone 2. The forecasts are based upon WoodMac's 2021 North American gas projections of Henry Hub prices plus projections of the basis differential to each hub from the Henry Hub. The basis differentials are obtained from the forward prices and assumed to be held constant based on the last year of available data. The projections of distillate and residual to electric generators in New England are drawn from AEO 2021.

Due to constraints in pipeline capacity, generating units in New England face shortages in natural gas supply during the winter period. To capture its impact, TCR included a winter gas cap to approximate the economic and environmental impact resulting from dual-fuel generators switching from natural gas to fuel oil on winter days with high natural gas prices. The fuel switching mechanism is included for all ENELYTIX® *i.e.*, the 83C III Base Case and all Proposal Cases. Additional details on the fuel switching mechanics are provided in an attachment to the 83C III Quantitative Protocol and revisited in the protocol addendum.

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23 North America gas 2021 outlook to 2050, published June 30, 2021, https://www.woodmac.com/reports/gas-markets-north-america-gas-2021-outlook-to-2050-505351

24 New England states are not subject to CSAPR. Some New England states have cap and trade programs for NOx and SO2, but the market is thin, prices are low, and allowances are often granted annually rather than auctioned.

Section 4.
Proposal Evaluation – Quantitative Workbook

TCR's Quantitative Analysis calculated the costs and benefits of each Proposal using a Quantitative Workbook for that Proposal. If a bid included an alternative pricing option for energy and RECs for a particular Proposal, TCR prepared a separate Quantitative Workbook for each pricing option included in the bid. The Quantitative Workbook is an Excel workbook consisting of a summary worksheet which summarizes the quantitative calculations from a proposal metrics worksheet. Four additional sheets are used for intermediate calculations – two GHG Inventory worksheets for the Proposal Case and 83C III Base Case, a worksheet for energy and price adjustments associated with existing long-term contracts, and a worksheet for calculating benefits of CPECs. Thirty-one additional supporting worksheets either report results or provide input to the intermediate and/or proposal metric worksheet. These additional worksheets report data drawn from the relevant bid, the Proposal Case modeling results and the 83C III Base Case modeling results.

The discussion that follows describes the GHG Inventory worksheet and the Proposal Metrics worksheet.

4.1: GHG Inventory Worksheet

The goal of the GHG Inventory Worksheet is to measure the incremental contribution of each Proposal towards meeting the Massachusetts GWSA relative to the 83C III Base Case.[25] TCR developed the GHG Inventory Worksheet to estimate the impact of the Proposal on the Massachusetts Department of Environmental Protection GHG Inventory following the general principles and methodology provided by DOER.

The GHG Inventory Worksheet calculates values for two types of GHG emission impacts of a Proposal on Massachusetts. First, it calculates changes in annual emissions (in metric tons of CO_2 equivalent) of grid energy generated in Massachusetts and/or imported into Massachusetts attributable to operation of the Proposal. Second, it calculates the changes in annual emissions associated with RECs used to comply with state RPS. The manner in which the Proposal's RECs are treated in each year is a function of market conditions and current law and regulation for compliance in Massachusetts and the other New England states. In particular, the RPS relies on markets, with ACPs, to incentivize new project development and retirements.

The GHG Inventory provides six major outputs by year for the period 2025 to 2050 that are then used as inputs to the calculations of Direct and Indirect Benefits of each Proposal. The six outputs are:

1. RECs from Project and Proxy (MWh) used towards MA RPS contract gap.[26]

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25 The Base Case GHG Inventory does not represent full implementation of all policies in the GWSA Clean Energy Compliance Plan (CECP) 2020 Update. Thus, its results should not be interpreted as a prediction of electric sector emissions. Instead, the Base Case GHG Inventory result simply helps determine the incremental impact of a Proposal on the electric sector. Refer to Appendix B.3 for additional details on the GWSA calculation methodology.

26 Massachusetts RPS contract gap equals the total quantity of RECs required to comply with the Massachusetts RPS in a year minus the quantity of non-83C III RECs under contract to comply with Massachusetts RPS in that year.

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2. RECs from Project and Proxy (MWh) used towards MA incremental CES contract gap[27]
3. RECs from Project and Proxy (MWh) sold out of state.
4. Residual quantity of RECs (MWh) purchased at market prices and retired to comply with Massachusetts RPS and / or incremental CES
5. Quantity of MA RPS and CES ACPs (MWh)
6. GWSA compliance contribution (GHG Inventory Impact) of Proposal in MWh. In each year, this contribution is calculated as the decrease in annual metric tons of CO_2 under the Proposal Case relative to the 83C III Base Case divided by the Base Case emissions rate. (The Base Case emissions rate in a given year is calculated as the metric tons of CO_2 emitted that year divided by the MWh of energy consumed in Massachusetts that year.)[28]

4.2: Proposal Metrics Worksheet

The Proposal Metrics worksheet of the Quantitative Workbook for a given Proposal develops values for each of the metrics used to calculate the Direct and Indirect Costs and Benefits of that Proposal Case. It develops annual values in 2021$ over an evaluation period of 2025 to 2050 and then calculates their respective present values.

The Proposal Metrics worksheet for each Proposal develops these annual values and present values from the following major inputs:

- Prices for energy and RECs from the bid
- Prices for energy and RECs for the proxy per 83C III Quantitative Protocol (as applicable)
- Details of generation units under existing and anticipated long term contracts with MA EDCs
- Results from ENELYTIX® modeling of the relevant Proposal Case
- Results from ENELYTIX® modeling of the 83C III Base Case
- Results from the GHG Inventory worksheet of the relevant Proposal Case, and
- The unit value per MWh of incremental contribution towards GWSA compliance.

27 Massachusetts incremental CES contract gap equals the total quantity of additional CECs (which are incremental to the MA RPS requirement) required to comply with the Massachusetts CES in a year minus the quantity of non-83C III CECs under contract to comply with the Massachusetts CES in that year.

28 See to Footnote 5

Section 5.
Scoring and Ranking of Proposal Cases

The Evaluation Team used the results from TCR's Quantitative Analyses and from the Qualitative Analyses performed by the 83C III Qualitative Evaluation Team, to score and then rank Proposals.

The scoring system was based on a 100-point scale. A Proposal Case could receive a maximum of 70 points based upon the results of its quantitative evaluation and a maximum of 30 points based upon the results of its qualitative evaluation. TCR developed the Quantitative Analysis scores assigned to each Proposal Case based upon the results of its quantitative evaluations. The 83C III Qualitative Team developed the scores assigned to each Proposal Case based upon the results of their Qualitative Analysis evaluations.

TCR assigned Quantitative Analysis scores to each Proposal Case based upon results of their respective Quantitative Analysis results pursuant to the following approach:

- Assign 70 points to the Proposal Case with the highest levelized unit Net Benefit, 2021$/MWh, ("top bidder");
- for each other bid, subtract 3.0 points for each $1.00/MWh of levelized unit Net Benefit that the bid is below the top bidder to determine the score for each remaining proposal.

The 83C III Qualitative Team provided TCR the scores assigned to each Proposal Case based upon results of their qualitative evaluations.

TCR added the quantitative and qualitative scores to calculate the total score of each Proposal Case. TCR then ranked each Proposal Case from high to low according to its total score.

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APPENDIX A:
Stage Two Proposal Scores and Ranking

A.1: Stage Two Scores and Ranking Based on National Grid + Unitil + DOER Team Qualitative Scores

83C_II Stage 2 Results

2. Stage 2 NG/Unitil/DOER Ranking <- Dropdown for Ranking Selection

Key: Proposal | *Proposal Sensitivity* | Portfolio | *Portfolio Sensitivity*

Results as of 12/14/2021

Evaluation Identifier	Total Contract Amount [Project / Proxy]	Number of Phases [Project / Proxy]	Project Proposed Annual Delivery (MWh)	Project Weighted Net Capacity Factor (%)	Project PPA Start Date (Start of first phase)	Sub total - Direct Cost of Proposal Energy + RECs	Remuneration Cost @ 2.75% Direct Cost of PPA	Sub total - Direct Benefit of Proposal Energy + RECs	Total Net Direct Benefit (Cost)	Total Net Indirect Benefit (Cost)	Net Benefit (Cost)	Net Benefit (Cost) Absolute value	Quantitative Score [Max 70]	Qualitative Score [Max 30]*	Total Score [Max 100]	Rank
[redacted]									7.79	30.52	38.31	$ 2,260,303,664	70.00	16.75	86.75	1
[redacted]									6.74	28.74	35.48	$ 2,091,360,873	61.52	19.50	81.02	2
[redacted]									6.23	29.61	35.83	$ 2,124,522,106	62.58	11.50	74.08	3
[redacted]									8.25	26.07	34.32	$ 1,965,555,990	58.04	12.75	70.79	4
[redacted]									6.72	26.07	32.79	$ 1,878,025,583	53.46	12.75	66.21	5
[redacted]									6.39	25.25	31.64	$ 1,825,742,801	50.01	11.50	61.51	6

[redacted]

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A.2: Stage Two Scores and Ranking based on Eversource Qualitative Scores

83C_II Stage 2 Results

1. Stage 2 ES Ranking <- Dropdown for Ranking Selection

Key: Proposal | *Proposal Sensitivity* | Portfolio | *Portfolio Sensitivity*

Results as of 12/14/2021

Evaluation Identifier	Total Contract Amount [Project / Proxy]	Number of Phases [Project / Proxy]	Project Proposed Annual Delivery (MWh)	Project Weighted Net Capacity Factor (%)	Project PPA Start Date (Start of first phase)	Sub total - Direct Cost of Proposal Energy + RECs	Remuneration Cost @ 2.75% Direct Cost of PPA	Sub total - Direct Benefit of Proposal Energy + RECs	Total Net Direct Benefit (Cost)	Total Net Indirect Benefit (Cost)	Net Benefit (Cost)	Net Benefit (Cost) Absolute value	Quantitative Score [Max 70]	Qualitative Score [Max 30]*	Total Score [Max 100]	Rank
[redacted]										28.74	35.48	$ 2,091,360,873	61.52	19.50	81.02	1
										30.52	38.31	$ 2,260,303,664	70.00	6.75	76.75	2
										29.61	35.83	$ 2,124,522,106	62.58	11.50	74.08	3
										26.07	34.32	$ 1,965,555,990	58.04	12.75	70.79	4
										26.07	32.79	$ 1,878,025,583	53.46	12.75	66.21	5
										25.25	31.64	$ 1,825,742,801	50.01	11.50	61.51	6

[redacted]

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APPENDIX B: **Stage Three Proposal Scores and Ranking**

B.1: Stage Three Scores and Ranking Based on National Grid + Unitil + DOER Qualitative Scores

83C_II Stage 2 Results

4. Stage 3 NG/Unitil/DOER Ranking <- Dropdown for Ranking Selection

Key: Proposal | *Proposal Sensitivity* | Portfolio | *Portfolio Sensitivity*

Results as of 12/14/2021

Row	Evaluation Identifier	Total Contract Amount [Project / Proxy]	Number of Phases [Project / Proxy]	Project Proposed Annual Delivery (MWh)	Project Weighted Net Capacity Factor (%)	Project PPA Start Date (Start of first phase)	Sub total - Direct Cost of Proposal Energy + RECs	Remuneration Cost @ 2.75% Direct Cost of PPA	Sub total - Direct Benefit of Proposal Energy + RECs	Total Net Direct Benefit (Cost)	Total Net Indirect Benefit (Cost)	Net Benefit (Cost)	Net Benefit (Cost) Absolute value	Quantitative Score [Max 70]	Qualitative Score [Max 30]*	Total Score [Max 100]	Rank
6	Portfolio 1 (CW1232 + MFWB2)	1600 MW / 0 MW	[2 / 0]	[redacted]	[redacted]	11/1/2027	54.91	1.51	62.69	6.26	32.40	38.66	$ 2,324,495,672	68.91	15.75	84.66	1
7	[redacted]									7.79	30.52	38.31	$ 2,260,303,664	67.84	16.75	84.59	2
8										6.22	30.74	36.97	$ 2,228,410,400	63.82	16.97	80.79	3
9										6.74	28.74	35.48	$ 2,091,360,873	59.36	19.50	78.86	4
10										6.05	32.98	39.03	$ 2,346,278,888	70.00	8.25	78.25	5
11										6.32	32.60	38.92	$ 2,340,081,882	69.69	8.25	77.94	6
12										6.60	29.75	36.35	$ 2,294,190,625	61.97	15.61	77.58	7
13										6.23	29.61	35.83	$ 2,124,522,106	60.42	11.50	71.92	8
14										4.55	29.31	33.87	$ 2,173,274,621	54.51	15.95	70.47	9
15										*6.26*	*27.44*	*33.70*	*$ 2,026,323,656*	*54.03*	*15.75*	*69.78*	*10*
16										8.25	26.07	34.32	$ 1,965,555,990	55.88	12.75	68.63	11
17										*6.22*	*25.77*	*31.99*	*$ 1,928,680,312*	*48.90*	*16.97*	*65.87*	*12*
18										6.72	26.07	32.79	$ 1,878,025,583	51.30	12.75	64.05	13
19										*6.60*	*25.03*	*31.63*	*$ 1,996,018,609*	*47.80*	*15.61*	*63.40*	*14*
20										*6.32*	*27.73*	*34.05*	*$ 2,046,831,252*	*55.06*	*8.25*	*63.31*	*15*
21										6.39	25.25	31.64	$ 1,825,742,801	47.85	11.50	59.35	16
22										*4.55*	*24.61*	*29.17*	*$ 1,871,747,998*	*40.42*	*15.95*	*56.37*	*17*

[redacted]

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B.2: Stage Three Scores and Ranking based on Eversource Qualitative Scores

83C_II Stage 2 Results

3. Stage 3 ES Ranking <- Dropdown for Ranking Selection

Key: Proposal | Proposal Sensitivity | Portfolio | Portfolio Sensitivity

Results as of 12/14/2021

Evaluation Identifier	Total Contract Amount [Project / Proxy]	Number of Phases [Project / Proxy]	Project Proposed Annual Delivery (MWh)	Project Weighted Net Capacity Factor (%)	Project PPA Start Date (Start of first phase)	Sub total - Direct Cost of Proposal Energy + RECs	Remuneration Cost @ 2.75% Direct Cost of PPA	Sub total - Direct Benefit of Proposal Energy + RECs	Total Net Direct Benefit (Cost)	Total Net Indirect Benefit (Cost)	Net Benefit (Cost)	Net Benefit (Cost) Absolute value	Quantitative Score [Max 70]	Qualitative Score [Max 30]*	Total Score [Max 100]	Rank
Portfolio 1 (CW1232 + MFWB2)	1600 MW / 0 MW	[2 / 0]	[redacted]	[redacted]	11/1/2027	54.91	1.51	62.69	6.26	32.40	38.66	$ 2,324,495,672	68.91	15.75	84.66	1
[redacted]									6.22	30.74	36.97	$ 2,228,410,400	63.82	16.97	80.79	2
									6.74	28.74	35.48	$ 2,091,360,873	59.36	19.50	78.86	3
									6.05	32.98	39.03	$ 2,346,278,888	70.00	8.25	78.25	4
									6.32	32.60	38.92	$ 2,340,081,882	69.69	8.25	77.94	5
									6.60	29.75	36.35	$ 2,294,190,625	61.97	15.61	77.58	6
									7.79	30.52	38.31	$ 2,260,303,664	67.84	6.75	74.59	7
									6.23	29.61	35.83	$ 2,124,522,106	60.42	11.50	71.92	8
									4.55	29.31	33.87	$ 2,173,274,621	54.51	15.95	70.47	9
									6.26	*27.44*	*33.70*	*$ 2,026,323,656*	*54.03*	*15.75*	*69.78*	*10*
									8.25	26.07	34.32	$ 1,965,555,990	55.88	12.75	68.63	11
									6.22	*25.77*	*31.99*	*$ 1,928,680,312*	*48.90*	*16.97*	*65.87*	*12*
									6.72	26.07	32.79	$ 1,878,025,583	51.30	12.75	64.05	13
									6.60	*25.03*	*31.63*	*$ 1,996,018,609*	*47.80*	*15.61*	*63.40*	*14*
									6.32	*27.73*	*34.05*	*$ 2,046,831,252*	*55.06*	*8.25*	*63.31*	*15*
									6.39	25.25	31.64	$ 1,825,742,801	47.85	11.50	59.35	16
									4.55	*24.61*	*29.17*	*$ 1,871,747,998*	*40.42*	*15.95*	*56.37*	*17*

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APPENDIX C:
Protocol for 83C III Quantitative Metric Calculations, Stage Two

C.1: Protocol for 83 III Quantitative Metric Calculations

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Protocol for 83C III Quantitative Metric Calculations, Stage 2

This document describes the quantitative metrics and multi-year net present value (NPV) cost/benefit analysis the evaluation team will use in Stage 2 to evaluate each of the proposals received in response to the Request For Proposals for Long-Term Contracts for Offshore Wind Energy Projects issued May 7, 2021 ("83C III RFP"). The inputs to many of those metrics will be drawn from the results of the analytic tool ENELYTIX licensed by Tabors Caramanis Rudkevich (TCR) to perform economic analyses of a Base Case and each Proposal Case.

1. The ultimate Stage 2 quantitative unit of comparison of proposals

In Stage 2 the core quantitative measure of comparison will be the levelized net unit benefit per MWh for each proposal calculated in 2021 dollars (2021$) over a study period of 2025 to 2050.[1] A bidder may offer less than the entire energy output from the capacity (MW) of an offshore wind energy project that is dedicated to a proposal but must offer all the Renewable Energy Certificates ("RECs") associated with those MWs. For bids that offer more RECs than MWh of energy, the number of RECs will be used in the levelized net unit per MWh calculation. Each proposal will be evaluated based on the simulated energy and RECs from 1,600 MW of offshore wind capacity consisting of the capacity specified in the bid for the offshore wind project ("OSW Project" or "Project") plus, as needed, proxy capacity ("OSW Proxy Units" or "Proxy Units") sized to supplement the bid capacity to total to the 1,600 MW ("Proposal").

2. The financial parameters to be used in the comparison of proposals

- Discount rate (nominal): 6.82%
- Rate of inflation: 2%[2]
- Discount rate (real based on $2021): 4.73%

3. Allocation of the 70 quantitative points

- Assign 70 points to the Proposal with the highest levelized net benefit per MWh ("top bid").[3]
- For each other Proposal, subtract 3 points for each $1.00/levelized net benefit per MWh that the bid has a levelized net benefit per MWh that is less favorable than that of the top bid.

4. Analytical approach per 83C III RFP requirements

Under the 83C III RFP, the Massachusetts Distribution Companies are seeking to procure at least 400 MW of Offshore Wind Energy Generation capacity, and up to a maximum of 1,600 MW. Section 2.2.1 allows bidders to submit Proposals from 200 MW up to 1,600 MW with no preferred bid size. Proposals larger than 400 MW are allowed to bid in phases as outlined in RFP Section 2.2.1.2 and Appendix K.

During Stage 2, all Projects, regardless of size,[4] will be evaluated as standalone Stage 2 Proposals, and the results of those evaluations will be combined with qualitative scores to develop a set of Stage 2

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[1] Assumes 2025 is earliest COD. 2030 is latest COD of a bid project per the RFP; 20 years is longest contract.

[2] 2% is consistent with assumptions in AESC 2021, inflation rates projected in the WEO 2021, CBO 2021) and assumptions in EIA AEO 2021

[3] Under a circumstance in which the Evaluation Team believes the bid with the highest levelized net benefit is an outlier, i.e., the net benefit per MWh of the bid is unreasonably different compared to that of the other bids, the Evaluation Team with unanimous agreement of all members and with input from the Independent Evaluator may award that bid an appropriate number of points, which will be the highest ranked bid, and award 70 points to the second highest bid. Scores of all other bids will then be relative to the second highest bid.

[4] Should there be Projects smaller than 400 MW, to be eligible for selection, they will be combined in a Portfolio with one or more other Projects to bring the total offshore capacity to within the procurement range and evaluated further in Stage 3 of the evaluation.

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Proposal rankings. In Stage 3, Stage 2 Proposals may be re-evaluated with Proposal specific adjustments that are described further in this protocol document and/or in the Stage 3 evaluation protocol, and may be aggregated with other Projects to produce Stage 3 Portfolios ("Portfolios") whose combined offshore wind capacity is within the procurement capacity range.

All Bidder's Proposals must provide for a scheduled commercial operation date (COD) before January 1, 2030. Bidder's Proposal to sell RECs or Offshore Wind Energy Generation and associated RECs pursuant to a Long-Term Contract must include the construction and operation of the Offshore Delivery Facilities and all associated facilities required for delivery from the Offshore Wind Energy Generation facilities directly to the corresponding onshore ISO-NE PTF system facilities, as well as the cost of associated network upgrades, and, if applicable, Energy Storage Systems.

As specified in Section 2.3.1 of the 83C III RFP, the Stage 2 quantitative analysis will determine the Direct Contract Costs and Benefits of each Proposal as well the Other Costs and Benefits to Retail Customers of each Proposal.

- Direct Contract Costs and Benefits will be determined primarily from comparison of specifications in the proposals as received (bid) and outputs from modeling of the Proposal using ENELYTIX[5] (i.e. the "Proposal Case").
- Other Costs and Benefits to Retail Customers will be determined by comparing the ENELYTIX results for the 'Proposal Case' to the ENELYTIX results for the 83C III "Base Case". The 83C III Base Case is a "but for" scenario that assumes no acquisition of any offshore wind power from this solicitation.

TCR will calculate each category of costs and benefits by year for each Proposal in an excel spreadsheet model ("Quantitative Evaluation Workbook") for that Proposal using the Proposal's bid prices and quantities and the results of its ENELYTIX modeling of the Proposal Case and Base Case, bidder responses to Evaluation Team questions and from other assumptions noted below.

5. Modeling Approach

ENELYTIX Modeling Assumptions & Modeling Process

The ENELYTIX modeling report ("83C III Input Assumptions Document") describes the ENELYTIX input and modeling assumptions that are common to the 83C III Base Case and all Proposal Cases.

- TCR will run the ENELYTIX capacity expansion and production cost (E&AS) model to establish a set of reference market conditions absent the selection and development of any proposal received in response to this 83C III RFP, the Base Case.
- TCR will also utilize ENELYTIX to model each Proposal Case to determine physical outputs and market prices such as projections of the annual quantities of energy and RECs that the Proposal will generate by year. Details on capacity expansion for Proposal Cases are provided in Attachment B.
- TCR will carry these results forward to the Quantitative Evaluation Workbook for the Proposal which it uses to determine the net benefits (benefits minus costs) for each Proposal. The quantitative spreadsheet model will calculate the NPV of the Proposal's annual costs and benefits as well as the levelized net unit benefit per MWh of generation of the Proposal.

[5] ENELYTIX modelling of each Proposal is used to determine relevant physical outputs and market prices such as projections of the annual quantities of energy and RECs that the Proposal will generate by year, the market prices for those products, and carbon emissions.

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All E&AS models will include a fuel switching mechanism for the winter period to reflect the impact on energy prices and emissions associated with dual-fuel generators switching from gas to fuel oil.[6]

Assumptions for Proxy Units for Proposal Cases

Each Proposal Case will assume the EDCs ultimately acquire 1,600 MW of new offshore capacity by 1/1/2030 consisting of the offshore wind capacity from the Project being evaluated and, if the Project being analyzed is less than 1,600 MW, additional balance OSW capacity is assumed to be available from Proxy Units representing offshore wind capacity procured in a subsequent 83C solicitation.

The 1,600 MW of new offshore capacity in each Proposal Case will consist of the following:

- Up to four tranches of the OSW Project which are modeled per bid specifications, including changes to the onshore transmission network as proposed by the bidder.
- Up to two additional tranches of OSW Proxy Units that would bring the overall OSW capacity to 1,600 MW by 1/1/2030. No additional transmission upgrades associated with Proxy Units are assumed. Any potential constraints in transmission are avoided, to the extent possible, by distributing the incremental energy across load centers in New England. Refer to the Proxy interconnection assumption below for further detail.

This approach with Proxy Units enables the evaluation to consider the opportunity costs and benefits of procuring greater than the minimum 400 MW in this solicitation as compared to the anticipated costs and benefits of procuring the installed capacity through a future solicitation, as contemplated in 83C III RFP Section 2.3.1.3.

Key parameters of the offshore Proxy Units:

- **Proxy PPA price:** Proxy Units' unit price will be the sum of the energy and REC prices of the corresponding OSW Project to which the Proxy Units are being added minus $0.01 per MWh in levelized 2021 dollars to be consistent with the price cap.
- **Proxy Capacity factor & hourly shape:** All Proxy Units will use the representative offshore wind production profile and have a capacity factor of 44.8%.[7]
- **Proxy Interconnection to onshore transmission network**: All Proxy Units will distribute generation across load centers in the ISO-NE system and will be modeled at a representative offshore wind interconnection node.[8,9]
- **Proxy Online Date & Capacity:** The buildout schedule for Proxy Units is based on several predefined guidelines introduced below to (i) accommodate a wide range of allowable bid capacities and timings, (ii) provide a consistent and comparable buildout to reduce the influence

[6] This captures the daily volatility in winter gas prices seen in New England which cannot be otherwise captured in monthly forecasts. Additional details on the background and methodology for fuel switching are contained in Attachment C.

[7] The representative offshore wind production profile represents generation based on an NREL defined offshore wind location situated within the New England offshore lease areas (latitude/longitude: 41.138123, -70.945648). This site has an estimated capacity factor that matches the weighted average capacity factors of all bids received in response to 83C I and 83C II solicitations. The capacity factor value proposed, as well as the underlying analysis of as-bid capacity factors, is based on a consistent 2012 weather year.

[8] The representative offshore wind interconnection node will proportionately distribute energy from offshore projects across all load centers in the Southeast Massachusetts (SEMA), Rhode Island (RI), Connecticut (CT), and Northeast Massachusetts (NEMA) ISO-NE energy areas.

[9] If this assumption is found to adversely impact one or more proposals due to congestion in the existing transmission network, affected proposals will be re-assessed in stage 3 assuming alternative POIs.

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of the Proxy Units on Project evaluations, and (iii) ensure that the addition of proxy capacity is reflective of a realistic future procurement.[10]

1. Proxy Units will be added in no more than two tranches ("Proxy Tranche 1" & "Proxy Tranche 2") which are assumed to have CODs of 1/1/2029 and 1/1/2030 respectively.[11]
   i. If the first tranche of the as-bid OSW Project comes online after 1/1/2029, then the online date of the Proxy Tranche 1 COD will be delayed to match the COD of the first tranche of the Project.
2. The total capacity of offshore wind that will be added in these tranches ("Total Proxy Capacity") for a given OSW Project equals 1,600 MW minus the total as-bid OSW Project capacity.
3. The capacity of the Proxy Tranche 1 unit will equal 800 MW minus the as-bid OSW Project capacity
   i. If the calculated capacity of the Proxy Tranche 1 unit is zero or negative, i.e. the OSW online Project capacity is greater than or equal to 800 MW then the capacity of the Proxy Tranche 1 unit is zero.
4. The capacity of the Proxy Tranche 2 unit will equal Total Proxy Capacity (step 2) less the Proxy Tranche 1 capacity (step 3).

Special Handling of Proposals Connecting to Cape Cod

The Base Case assumes that all existing EDC contracts are modeled at the POI listed in their respective contracts, accounting for known updates from the EDCs, project developers, and ISO-NE. Therefore, the entire approximately 800 MW from the 83C II contracts is modeled at the Falmouth 345 kV bus. However, due to the ongoing ISO-NE Cape Cod Cluster Study process, certain potential bids may have priority to interconnection capacity ahead of the 83C II contract generation. The following rules will apply to all bids connecting to Cape Cod: [12]

1. **Bids on Cape Cod exclusively using earlier queue position(s) than that associated with the 83C II contracts:**

- If such bid is less than or equal to 427 MW,[13] the Proposal Case models the 83C II Contracts as present in the Base Case and no other change is made.
- If such bid is greater than 427 MW, subtract the MW capacity of such bid from 1,227 MW. This difference is the MW capacity of the 83C II contracts that will be modeled at the Falmouth 345

[10] Bid structures that require Proxy Unit additions outside of the conditions describe herein will be developed and evaluated in Phase 3.

[11] This allows for the remainder of the 1,600 MW by 1/1/2030 target additions be built in phases. 1/1/2029 is assumed to be the earliest date that a future solicitation may come online, taking into consideration an assumed 2-year time window after the current 2022 solicitation and an additional 5 years from contract signing to COD. 1/1/2030 aligns with the latest allowable COD in the 83C III RFP ("earlier than 1/1/2030") and is consistent with the MA GWSA target for 1,600 MW of offshore wind added by 2030.

[12] Bids not interconnecting on Cape Cod are not eligible for either Cape Cod Cluster Study and will not have any interconnection uncertainty due to the 83C II contracts.

[13] For purposes of this document, the 427 MW threshold is calculated assuming the first cluster is sized at exactly 1,227 MW and the 83C II contracts being approximately 800 MW in total. The threshold value is subject to being updated at the time of evaluation to reflect the best information available at that time. Any revisions to this value will need to be approved by the Evaluation Team and will be applied consistently across all bids.

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kV bus. The remaining MW of the 83C II contracts will be removed from the Falmouth 345 kV location and spread across SEMA and RI. [14]

- Regardless of the size of such bid, all Proposal Cases will be evaluated against the original Base Case, unless evidence appears during evaluation that a comparison against a revised Base Case might also be necessary or appropriate to assure a fair evaluation of all bids.

2. **Bids on Cape Cod fully or partially using queue positions that are later in the queue than the queue position associated with the 83C II contracts:**

    - Any bids in this category will either be fully or partially included in the 2nd Cape Cod Cluster (unless they have queue positions included in the first Cape Cod Cluster due to decisions made by companies holding earlier queue positions) and must include any additional required transmission upgrades beyond the 1st cluster. Therefore, these bids do not require any revisions to the Base Case.

Special Handling of Production Cost ENELYTIX Modeling Process

In the event that the existing transmission network becomes insufficient to handle increased loads in outer years as high levels of renewable penetration appear as unresolvable transmission violations and/or load shedding in detailed nodal modeling, the Base Case and Proposal Case modeling process will be modified as follows:

- Run the capacity expansion model as has been normally done (do not enforce local constraints)
- Run a nodal production cost model based on the capacity expansion buildout
- Identify the year when the current transmission model starts reporting load shedding/ significant transmission violations
- Run the remaining years of the production cost model without enforcing local constraints i.e. only enforce interfaces constraints.

6. Criteria for evaluation and the procedure for their calculation

The 83C III RFP specifies two categories of quantitative evaluation criteria or metrics, Direct Contract Costs & Benefits and Other Costs and Benefits to Retail Customers. This section describes the calculation procedure, and information sources, for each of those criteria.

A. CALCULATION OF DIRECT COSTS & BENEFIT METRICS

1. **A mark-to-market comparison of the price of any eligible Offshore Wind Energy Generation under a contract to projected market prices at the delivery point with the Project in-service.**

    a. Calculate the annual market value ($) of energy delivered by the Proposal at the delivery node(s) over the Proposal contract period accounting for contract delivery conditions. Annual market value ($) equals the sum over the year of the quantity of energy delivered at nodes in each hour of year times hourly Locational Marginal Prices (LMPs) at the node.

    b. Calculate the annual cost ($) of energy from the Proposal over the Proposal contract period accounting for contract delivery conditions (peak, off-peak, etc.) and bid prices.

    c. Calculate the annual net benefit of the energy from the Proposal as the market, LMP-based value of energy from the Proposal at the point of delivery minus the annual cost ($) of energy from the Proposal (step A.1.a results minus step A.1.b results).

[14] Generation will be proportionately distributed across all load centers in the Southeast Massachusetts (SEMA) and Rhode Island (RI).

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2. Comparison of the price of any Renewable Portfolio Standard ("RPS") Class I eligible RECs under a contract to: (i) the avoided cost with the Project not in-service if the RECs are to be used for RPS and Clean Energy Standard ("CES") compliance by the Distribution Companies or Massachusetts retail electric suppliers; and (ii) their projected market prices with the Project in-service if the RECs are projected to be sold.

a. For each year, calculate the MA Class 1 RPS and MA CES compliance obligation of the distribution service retail load served by Massachusetts Electric Distribution Companies (EDCs).

b. Identify the Class 1 RECs[15] and Clean Energy Credits ("CECs)[16] that MA EDCs are holding or will hold under long-term contracts in each year. (These are MA EDC existing contracts from 83D, 83C I, 83C II, as well as from prior solicitations).[17]

c. Calculate over the Proposal contract period the direct annual cost of the proposal's Class 1 RECs as the annual quantity of the Proposal RECs times the Proposal's annual bid price for RECs

d. Calculate over the Proposal contract period the MA Class 1 RPS and MA CES compliance obligation that could be met with the Class I RECs from the Proposal, i.e. the RPS and CES Gap. (RPS and CES Gap = Step A.2.a minus Step A.2.b. If the result of this calculation is negative, the RPS and CES Gap equals zero)

e. Calculate over the Proposal contract period the direct annual dollar benefit of Proposal RECs used for MA Class 1 RPS and MA CES compliance obligation (the lesser of the Proposal RECs or the RPS and CES Gap) as the avoided cost of meeting that obligation at the market price of Class 1 RECs/CECs in the Base Case (direct annual dollar benefit of Proposal RECs used = Proposal RECs used to meet the MA Class 1 RPS and MA CES compliance obligation * Base Case REC Market Price).

f. Calculate over the Proposal contract period the direct annual dollar benefit of Proposal RECs sold as the remaining Proposal RECs not used for MA Class 1 RPS and MA CES compliance times the market price of Class 1 RECs in the Proposal Case. (direct annual dollar benefit of Proposal RECs sold = (Proposal RECs – Proposal RECs used to meet MA compliance) * Proposal Case Market Price for REC or CEC whichever is higher)

g. Calculate the total net direct benefit of RECs as the sum of Steps A.2.e and A.2.f minus step A.2.c.

3. Benefit of Proposal's contribution to Massachusetts Clean Peak Standard (CPS)[18]

a. Benefits from contribution to CPS is attributed to Proposals / proposal tranches[19] that dispatch into the electric distribution system in Massachusetts (NEMA, SEMA, WCMA). For Proposals / Proposal tranches that dispatch to non-Massachusetts areas, the credit is zero.

b. Calculate over the Proposal contract period the total quantity of annual Clean Peak Energy Certificates (CPECs) credited to the Proposal by aggregating the energy (MWh) generated by

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[15] Class 1 RECs may be used for either MA RPS or MA CES compliance.
[16] CECs from the selected 83D project may only be used for CES compliance, not RPS.
[17] RECs or CECs from potential future EDC contracts beyond the 1,600 MW being procured under the 83C III solicitation are not included in this calculation.
[18] 225 CMR https://www.mass.gov/doc/clean-peak-energy-standard-final-regulation/download
[19] Proxy Units are assumed to partially contribute to CPECs in proportion to the fraction of energy load distributed to the MA energy areas per the assumed POI. The Proxy POI distributes an aggregate of 51.2% of the energy to MA.

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the Proposal[20] during eligible peak periods[21] and adjusted by multipliers[22] per the CPS regulations and outlined below:

#	Peak Period[23]	Dates	Period	Seasonal Multiplier	Contracted Gen Multiplier	Monthly Peak Multiplier
i	Spring Clean Peak Season	March 1 to May 14	5 pm to 9 pm	1	0.01	-
ii	Summer Clean Peak Season	May 15 to September 14	3 pm to 7 pm	4	0.01	-
iii	Fall Clean Peak Season	September 15 to November 30	4 pm to 8 pm	1	0.01	-
iv	Winter Clean Peak	December 1 to February 28/29	4 pm to 8 pm	4	0.01	-
v	Monthly System Peak	Day with ISO-NE wide peak	Peak hour	1 or 4	0.01	25

c. Calculate the total dollar benefit in each year by multiplying the total CPECs (MWh) calculated in 1.b in each year to an assumed price ($/MWh) of CPECs, valued at the cost of Alternative Compliance Payments (ACPs)[24] for that year. ACP Prices are reproduced below.

Year	ACP (Nominal$/ MWh)	Year	ACP (Nominal$/ MWh)	Year	ACP (Nominal$/ MWh)	Year	ACP (Nominal$/ MWh)
2025	43.46	**2032**	32.68	**2039**	21.90	**2046**	11.12
2026	41.92	**2033**	31.14	**2040**	20.36	**2047**	9.58
2027	40.38	**2034**	29.60	**2041**	18.82	**2048**	8.04
2028	38.84	**2035**	28.06	**2042**	17.28	**2049**	6.50
2029	37.30	**2036**	26.52	**2043**	15.74	**2050**	4.96
2030	35.76	**2037**	24.98	**2044**	14.20		
2031	34.22	**2038**	23.44	**2045**	12.66		

4. Calculate Total direct net benefits of the Proposal as the sum of A.1.c, A.2.g, and A.3.c

[20] All generation from storage included in Proposals are considered eligible for CPECs as they are contractually paired with a qualified RPS resource. 225 CMR § 21.05 (1) (a) 2. b.

[21] 225 CMR § 21.05 (4)

[22] 225 CMR § 21.05 (6) (a), (b), (e)

[23] The benefit calculation assumes peak periods are held constant over the evaluation period. However, if this assumption is determined to materially impact and/or benefit the evaluation, the periods will be revised to better reflect the change in peak periods that may occur as a function of electrification during the evaluation period.

[24] 225 CMR § 21.08 (3) 2. Values published in Nominal $ converted to 2021$ recognizing that ACP is the highest possible benefit that can be achieved.

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B. CALCULATION OF OTHER COST & BENEFIT METRICS[25]

1. Impact of changes to the Locational Marginal Price ("LMP") paid by ratepayers in the Commonwealth.

a. For the Proposal case, calculate the annual market value ($) of energy supplied to Massachusetts retail customers in each year starting from the contract proposal start date through the end of the study period, 2050. The annual market value of energy equals the sum over the year of the quantity of energy supplied in each Massachusetts load zone (SEMA, WCMA and NMABO) in each hour of year times hourly LMPs in each load zone.

b. Adjust the Proposal case annual market value of energy by the proportion of MA EDC distribution service retail load to total load in each Massachusetts load zone. The result is the zonal LMP-based total cost of energy to MA EDC distribution service customers in the Proposal case.

c. For the Base case, calculate the annual market value of energy supplied to ratepayers in each year starting from the Proposal contract start date through the end of the study period, 2050. Annual market value of energy equals the sum over the year of the quantity of energy supplied in each Massachusetts load zone (SEMA, WCMA and NMABO) in each hour of year times hourly LMPs in each load zone.

d. Adjust the Base case annual market value of energy by the proportion of MA EDC distribution service retail load to total load in each Massachusetts load zone. The result is the zonal LMP-based total cost of energy to MA EDC distribution service customers in the Base case.

e. Calculate the gross energy market price change impact of the Proposal on the total cost of energy to MA EDC distribution service customers as the Base Case cost of energy to EDC distribution customers from B.1.d minus the Proposal case cost of energy to EDC distribution customers from B.1.b.

f. Calculate the change in the aggregate market value of energy from all EDC contracts in the Base Case, i.e., without the OSW Project in service. The change in market value of each EDC contract equals the quantity of energy from that contract at the delivery node in each hour of year multiplied by the difference between the hourly LMP at that node in the Base case and in the Proposal Case for the respective terms of the EDC contracts.

g. Calculate the net energy market price change impact of the Proposal starting from the Proposal contract start date through the end of the study period, 2050 on the total cost of energy to MA EDC distribution service customers by adding the change in the aggregate market value of energy from all EDC contracts in the Base Case from B.1.f. to the gross energy price change impact from B.1.e.

2. Impact on RPS and/or CES compliance costs paid by ratepayers in the Commonwealth

a. For the Proposal Case calculate the annual quantity of Class 1 RECs that will be acquired from the market to meet the RPS / CES requirement associated with EDC distribution service. This quantity equals the total quantity required for compliance minus the aggregate quantity from EDC contracts in the Base Case[26] and minus the Proposal and Proxy RECs.

b. Calculate the REC market price change under the Proposal Case ($MWh) as the REC market price in the Base Case minus the REC market price in the Proposal Case.

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[25] The Evaluation Team determined that the indirect impacts of Proposals on capacity or ancillary service market prices were not reliably quantifiable and therefore did not include those impacts in the evaluation.

[26] Refer to Footnote 17

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c. Calculate the REC market price change impact of the Proposal as the annual quantity of Class 1 RECs that will be acquired from the market, from B.2.a, multiplied by the REC market price change from B.2.b starting from the contract Proposal start date through the end of the study period, 2050.

3. **Impact of the Proposal on the Commonwealth's ability to meet Global Warming Solutions Act (GWSA) requirements in excess of compliance with the RPS and the CES.**

   a. Calculate the Incremental Inventory Impact in MWh per Attachment A starting from the Proposal contract start date through the end of the study period, 2050.

   b. Subtract the quantity (MWh) of Class 1 RECs used for MA RPS or CES compliance by each Proposal Case from the Inventory Impact (MWh).

   c. Calculate the incremental benefit ($) by multiplying the result from B.3.b by $17.76 2021$/MWh.[27] [28]

4. **Impact of a change in Proposal PPA market value in a year with extreme winter gas prices.**

   a. Calculate the 3-month average of the daily spot Algonquin Citygate (AGC) gas prices for historical winter periods (December – February) for each year 2002 through 2021. [29]

   b. Identify the winter periods with the highest average AGC price and the lowest AGC price.

   c. Compute the average of all historic winter AGC prices, 2002 through 2021. Calculate the highest and lowest historical winter average AGC price as a percentage over or under the historic average winter AGC price.

   d. Compute the ratio of the total historic gas consumption (MMBtu) for the winter of the highest average AGC price to the total gas consumption December through February for the modeled winter 2030/2031 period assuming Proposal Case resources. Compute this same ratio for the winter of the lowest average AGC price. [30]

   e. Adjust the percentage over/under the average for the highest and the lowest historic winter average AGC price by the fuel consumption ratios computed in step 4d. Apply the adjusted gas price over/under factors (high and low) to derive high and low winter gas prices for the three winter months in the 2030/2031 power year.

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[27] $17.76 2021$/MWh is $16.51 /MWh (2017$), the unit value of the incremental inventory impact used in the 83C I evaluations expressed in 2021$/MWh.

[28] National Grid's concerns with the methodology and compliance value used in the calculation of the GWSA compliance contribution benefits by DOER, Eversource, and Unitil were set out in detail in its response to Information Request DPU-5-12 in the 83C Round 1 solicitation, *Joint Petition of NSTAR Electric Company et al*., D.P.U. 18-76/77/78, and in its response to Information Request DPU-2-14 in the 83D solicitation, *Joint Petition of NSTAR Electric Company et al.*, D.P.U. 18-64/65/66. Despite these concerns, National Grid does not intend to sponsor a separate, alternative GWSA net benefit calculation in the current solicitation. This is because National Grid does not believe that the differences between its own version of the GWSA calculation (described in the Information Request responses cited above) and the DOER/Eversource/Unitil version will be material under the particular facts and circumstances of the current 83C Round 3 solicitation. In the event that, contrary to National Grid's expectation, the calculated GWSA compliance contribution benefits appear to have a material impact on the ranking of Proposals or Portfolios, National Grid may consider it appropriate to exclude this impact from its own evaluation and/or rankings, perhaps as part of the Stage 3 evaluation.

[29] This is the period for which published statistics are available. Gas prices on days with no reported prices are assumed to equal the price for the most recent preceding day for which there were reported prices.

[30] This ratio is a scaling factor to reduce the magnitude of the historical extreme variation to reflect the reduction in pipeline constraints in the Proposal Case relative to the historical period due lower gas use.

f. Calculate the value of the energy ($) delivered by the Project in the Proposal Case for the three winter months in the 2030/2031 power year assuming Proposal Case resources and Base Case fuel prices. Calculate the value of the energy delivered by the proposal using the adjusted high[31] and adjusted low winter gas prices assuming Proposal Case resources.

g. Calculate the percentage changes in the annual Proposal contract market value in a year with the adjusted high and low winter gas prices. These percentages equal the energy cost to MA consumers in the 2030/2031 winter under the respective high and low winter gas price scenarios assuming Proposal Case resources divided by the annual energy cost to MA consumers in the 2030/2031 power year under the Proposal Case.

h. Calculate the net percentage change due to extreme winter prices as the high winter gas price percentage change minus the absolute value of the low winter gas price percentage change.

i. Divide the percentage change in the Proposal PPA market value in a year with extreme winter gas prices from B.4.h by 20 (the maximum contract period). Apply that percentage to the annual value of the PPA in each year over the Proposal contract period. (This approach reflects the uncertainty regarding the specific year in which an extreme winter gas price event might occur during the study period.)

5. Total indirect net benefits of the Proposal

a. Calculate the annual sum of the indirect benefits as the sum of B.1.g, B.2.c. B.3.c, and B.4.i.

C. CALCULATION OF PROPOSAL TOTAL QUANTITATIVE BENEFITS

1. Calculate the annual sum of the direct and indirect benefits as A.4 plus B.5.a.

2. Calculation of the total net unit benefit of the Proposal:

a. Compute the present value of the annual direct costs, direct benefits, and indirect benefits in $2021. Discount to 2021 reference year at the real discount rate.

b. Compute the present value of the net benefit as the sum of the present values of direct benefits and indirect benefits, less the present value of direct costs.

c. Compute the present value of the annual MWh of energy delivered to the system from the Proposal (i.e. OSW Project as bid and Proxy Units as appropriate) consistent with a total of 1,600 MW. The annual energy quantities should be discounted to 2021 reference year using the real discount rate.

d. Divide the result of step 2 by the result of step 3 to compute the levelized unit net benefit for the Proposal. This result will be expressed in 2021 constant dollars per MWh.

D. QUANTITATIVE EVALUATION CALCULATIONS

Other benefits prior to Proposal PPA. Any difference in prices or emissions between the Proposal Case and the Base Case reported for the years prior to the start date of the Proposal PPA, or the OSW Project COD will be excluded from the calculations. Such differences are idiosyncratic and qualify as ‘noise’ within the modelling environment.

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[31] This calculation captures the impact of a Proposal on costs to ratepayers in a year with an extreme winter event (such as a “polar vortex”). This impact is not captured in any of the other evaluation metrics because the projections for hourly load and monthly gas prices used in the Base Case and each Proposal Case reflect normal weather variations by season. The specific timing and magnitude and timing of an extreme winter event, should one occur during the study period, is unknown.

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OSW Project energy and REC quantities, costs and market value impacts during PPA period.
Quantities from, and /or impacts of, OSW Projects that start / end during a calendar year will be reported for the relevant partial year periods.

ATTACHMENT A – GREENHOUSE GAS INVENTORY CALCULATIONS

ATTACHMENT B - CAPACITY EXPANSION FOR 83C III OSW PROJECT

ATTACHMENT C – WINTER FUEL SWITCHING METHODOLOGY

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Attachment A - GHG Inventory Calculation Protocol

In order to calculate the impact an 83C III Proposal project (“Proposal”) or a Portfolio of Proposals (“Portfolio”) has on GWSA compliance, the Evaluation Team will utilize the following methodology that estimates the Proposal’s or Portfolio’s impact on the Massachusetts Department of Environmental Protection Greenhouse Gas (GHG) Inventory (“Inventory”). The Evaluation Team will measure the Incremental Inventory Impact of each Proposal and Portfolio relative to the 83C III Base Case.[32] The Impact of a Proposal will equal the impact of the proposed Project plus, for Projects smaller than 1,600 MW, that of a Proxy Unit or Units sized to supplement the Project capacity to total 1,600 MW.

The methodology uses a GHG Inventory spreadsheet model (GHG workbook) to capture the two major types of GHG emission impacts an 83C III Proposal has on Massachusetts. First, it captures the changes in emission rates of grid energy generated in Massachusetts and/or imported into Massachusetts caused by the expected dispatch of the 83C III Proposal. Second, it captures the inventory impacts caused by the renewable energy credits (RECs) from the 83C III Proposal that are used to comply with state renewable portfolio standards (RPS) and/or the Massachusetts Clean Energy Standard (CES) as well those that are retired solely for GWSA compliance. The way the Proposal’s RECs are modeled in each year is a function of market conditions and current law and regulation for compliance in Massachusetts and the other New England states. In particular, the RPS and CES mechanisms each rely on markets, as well as alternative compliance payments (ACPs), to incentivize new project development and retirements.

The Evaluation Team will use the GHG workbook to determine the impact of each 83C III Proposal on the Inventory on a level playing field regardless of the specific 83C III energy resource. This methodology will produce the following eight major outputs by year for the period 2025 to 2050:[33]

1. RECs from Project (MWh) used towards Massachusetts RPS contract gap.
2. RECs from Proxy Units, if applicable (MWh) used towards Massachusetts RPS contract gap.
3. RECs from Project (MWh) used towards Massachusetts incremental CES contract gap
4. RECs from Proxy Units (MWh) used towards Massachusetts incremental CES contract gap
5. Residual quantity of RECs (MWh) purchased at market prices to comply with Massachusetts RPS and/or incremental CES
6. RECs from Project (MWh) sold out of state.
7. RECs from Proxy Units (MWh) sold out of state.
8. GWSA compliance contribution (GHG Inventory Impact) of Proposal (MWh).

For each Proposal and Portfolio, those outputs from the GHG workbook will be inputs to the quantitative spreadsheet model that produces outputs used to determine the Direct Benefits and Indirect Benefits as well as the associated incremental GWSA compliance benefit of the Proposal or Portfolio.

[32] The Base Case Model amount does not represent the full implementation of all GWSA and 2030 CECP policies and the associated Inventory results should not be interpreted as a prediction of electric sector emissions. Instead, the Base Case Inventory result is used only to determine the impact of a Proposal or a Portfolio on the electric sector.

[33] Massachusetts RPS contract gap equals the total quantity of RECs required to comply with the Massachusetts RPS in a year minus the quantity of non-Proposal RECs under contract (including previously contracted 83C resources) to comply with Massachusetts RPS in that year. Massachusetts incremental CES contract gap equals the total quantity of Clean Energy Certificates (CECs) required to comply with the Massachusetts CES requirements in a year incremental to the RPS minus the quantity of non-Proposal CECs under contract including the Environmental Attributes produced by 83D resources to comply with the incremental Massachusetts CES requirement in that year.

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A. GHG WORKBOOK INPUTS AND ASSUMPTIONS

The Inventory Impact of a Proposal is ultimately calculated as a delta between the GHG inventory for that Proposal's Case and the GHG inventory for the 83C III Base Case. The team will use the GHG workbook to calculate the GHG inventory for each Proposal Case and for the 83C III Base Case using outputs from ENELYTIX modeling of those Cases ("the Model") as well as a set of inputs common to each Case. The GHG workbook will calculate the forecast GHG Inventory for each Case in million metric tons CO2e ("MMT CO2e") for every year between 2025 and 2050.[34]

The GHG workbook calculation will use the following outputs from the Model. Unless noted, the outputs come from the Model's E&AS module.

- **Annual Generation (MWh):** The total generation in each New England (NE) state, not counting behind-the-meter PV (which is reflected in Annual Load)
- **Annual Seabrook Generation and Annual Millstone Generation (MWh)**
- **Imports (MWh) from NY, Quebec, and New Brunswick/PEI ("external control areas")** into New England, as well as imports from Quebec, Ontario, and PJM into New York
- **Annual Total RECs Produced:** The number of RECs produced in each NE state and external control area that are retired annually in New England[35]
- **Annual 83C III Proposal RECs Produced**: The number of RECs produced in each NE state and external control area by the Proposal or Portfolio
- **Annual Non-Biogenic Emissions (metric tons CO2e)**: Emissions from non-biogenic fuel, per Table 1, from generators in each NE state and New York
- **Annual REC Price ($/MWh):** The REC price projected by the Model's capacity expansion module[36]
- **Annual CEC Price ($/MWh):** The price for Massachusetts Clean Energy Certificates projected by the Model's capacity expansion module
- **Annual Regional RPS ACP Quantity (MWh)**: The total quantity of all NE states' RPS requirements minus total RECs produced, when that difference is positive. This quantity is projected by the Model's capacity expansion module.

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[34] Assumes 2025 is earliest COD. The RFP says January 1, 2030 is the latest COD of a bid project and of a Tranche 2 Proxy Unit where the bid project is less than 1,600 MW; 20 years is longest contract.

[35] The quantities of Annual Total RECs imported from each external control area are adjusted slightly so that the regional REC supply is consistent with the RPS and CES supply and demand conditions as indicated by outputs of the Model's capacity expansion module (REC and CEC prices, and ACP quantities required to comply with all states' RPSs and the Massachusetts CES). These small differences exist because the Model's E&AS module, unlike the capacity expansion module, does not enforce RPS and CES constraints. The quantities of Annual Total RECs imported from external control areas are also reallocated among areas as needed to ensure that the quantity of RECs imported from any one external area does not exceed the energy imported from that area—a constraint not enforced in ENELYTIX.

[36] Annual REC and CEC prices are used solely in the adjustment of Annual Total RECs imported from each external control area, as described in Footnote 35.

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- **Annual Massachusetts CES ACP Quantity (MWh)**: The quantity by which the incremental CES requirement is projected to exceed the attributes used to meet it. This value is projected by the Model's capacity expansion module.
- **Annual Non-Proposal RECs under Long-Term Contract to Massachusetts EDCs**: The number of RECs produced in each NE state and external control area by resources (or portions of resources) that are under long-term contract to Massachusetts EDCs.

The GHG workbook will use the following assumptions in addition to those used in ENELYTIX modeling. These quantities are the same for all cases, with details provided in Tables 2 through 5.

- **State loads (MWh)**. The generation required to supply the retail load of each state in each year.
- **Annual Environmental Attributes (EAs) produced by 83D resources**: The non-Class 1 clean energy produced in each NE state and external control area by 83D resources expected to be under long-term contract to Massachusetts EDCs and potentially eligible for compliance with the Massachusetts Clean Energy Standard.
- **Annual RECs produced by 83C I and 83C II resources**.
- **Massachusetts Municipal Wholesale Electric Company (MMWEC) ownership/contract share** of Millstone Nuclear Power Station output and Seabrook Nuclear Power Station output, by year.[37]
- **Connecticut EDC contract entitlement to Seabrook Nuclear Power Station output** (18.4% through 2029).
- **Emission rates for imports from Canada** (lbs. CO2e/MWh): Emission rates for imports from Quebec and New Brunswick into New England and from Quebec and Ontario into New York will remain constant at the levels in the 2021 Canadian greenhouse gas inventory.[38]
- **Emission rate for imports from PJM into New York** (lbs CO2e/MWh): Emission rates for imports from PJM will remain constant at the level in the 2020 PJM emissions report.[39]
- **2020 REC Oversupply Allocation**: The percentage of unsettled and reserved certificates in the NEPOOL GIS system that are eligible for the states' Class or Tier 1 RPS (as reported to state regulators for 2020).[40] These quantities are used in the calculation of the Annual REC Oversupply Allocation.

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[37] For Seabrook, this includes ownership/contract shares of the Taunton Municipal Lighting Plant, and the Hudson Light & Power Department.

[38] Preliminary rates for 2019, Tables A13-5 and A13-6, Annex 13, "National Inventory Report 1990–2019: Greenhouse Gas Sources and Sinks in Canada," Environment Canada, 2021. https://publications.gc.ca/site/eng/9.506002/publication.html.

[39] Average rate for 2020, Table 2, "2016–2020 CO2, SO2 and NOx Emission Rates," PJM, April 9, 2021. https://www.pjm.com/-/media/library/reports-notices/special-reports/2020/2020-emissions-report.ashx.

[40] These certificates were not retired for compliance for any Class 1 or Tier 1 RPS but were included in the MassDEP Greenhouse Gas Inventory calculation.

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B. GHG WORKBOOK OUTPUTS

1. Outputs 1 through 4 — Project and Proxy RECs retired for compliance with Massachusetts RPS and/or CES[41]

RECs from Proposals in each year are accounted as follows:

a. Non-Proposal RECs under contract to the Massachusetts EDCs are subtracted from the Massachusetts RPS requirement.

b. EAs under contract to the Massachusetts EDCs are retired for compliance with the Massachusetts incremental CES requirement.

c. Project RECs. If there is a remaining RPS gap, Project RECs are deemed to be retired for the Massachusetts EDCs' compliance with the Massachusetts RPS (including offsetting Massachusetts competitive suppliers Massachusetts RPS obligations). If the gap is less than the Project RECs, then the quantity of Project RECs retired for compliance with the Massachusetts RPS is the size of the gap. If there is a remaining incremental CES gap, and there are any remaining Project RECs, they are available for compliance with the CES. If there are Project RECs remaining after compliance with the CES, they are available for sale out of state.

d. Proxy RECs. If there is a remaining RPS gap, Proxy RECs are deemed to be used for compliance with the Massachusetts RPS (including offsetting Massachusetts competitive suppliers Massachusetts RPS obligations). If there are remaining Proxy RECs, and there is a remaining incremental CES gap, the remaining Proxy RECs are used to comply with the CES. Any remaining Proxy RECs are deemed available for sale out of state.[42]

2. Output 5 — Residual RECs purchased at market prices for compliance with Massachusetts RPS and CES

If, after applying Proposal RECs to meet the Massachusetts RPS compliance gap, there remains a compliance gap, RECs purchased at market prices will be used for compliance. Those will consist of market RECs from Massachusetts and—if needed—from other NE states and external control areas. In the event of a regional RPS deficiency, the deficiency will be deemed to be consolidated in Massachusetts and Connecticut, the states that share the lowest RPS ACP in New England.[43] The regional RPS deficiency will be allocated between Massachusetts and Connecticut in proportion to their RPS requirements.

If, after surplus RECs have been transferred among states to satisfy RPS deficiencies, a CES compliance gap and a surplus of RECs remain, those RECs (beginning with RECs in Massachusetts) will be used to satisfy the gap.

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[41] The Massachusetts RPS and CES requirements discussed throughout include both the requirements of the Massachusetts EDCs and those of competitive retail suppliers.

[42] As noted above, Massachusetts RPS and CES requirements discussed throughout include both the requirements of the Massachusetts EDCs and those of competitive retail suppliers. In the calculation, proposal RECs are deemed available for sale out of state only if the entire Massachusetts RPS and CES requirements are satisfied.

[43] 225 CMR 14.00: Renewable energy portfolio standard - Class I, https://www.mass.gov/regulations/225-CMR-1400-renewable-energy-portfolio-standard-class-i

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3. Outputs 6 and 7 — Project RECs and Proxy RECs sold out of state

In the calculation, out-of-state sales of Proposal RECs can occur only when Massachusetts obligations are satisfied and a surplus (but not regional oversupply) of RECs remains, which is used toward RPS compliance deficiencies in other NE states. If there is a regional oversupply of RECs, an allocation of the regional oversupply will result in all Proposal RECs (as well as 83C RECs already under contract) being retained in Massachusetts, and not sold out of state.

The quantity of Proposal RECs sold out of state in a given year is determined as follows:

a. If the Massachusetts RPS and CES are satisfied and there is a MA REC surplus that includes 83C III Proposal RECs (and potentially market RECs), referred to here as the "original surplus," that original surplus is used toward RPS compliance deficiencies in other NE states.

b. If after the transfers of Step a, there is no remaining MA REC surplus, the 83C III Project and Proxy RECs sold out of state are the quantities of such RECs that had remained after the MA RPS and CES were satisfied.

c. If after the transfers of Step a, a regional surplus of RECs remains ("remaining surplus"), the difference between the original surplus and the remaining surplus times the proportions of Project and Proxy RECs in the original surplus yield the quantities of Project and Proxy RECs sold out of state.

If there is a regional oversupply of RECs, the allocation of the surplus across states is calculated as follows:

d. The 83C RECs in the regional REC oversupply will be allocated to Massachusetts, and the non-83C RECs will be allocated among all NE states (as described in Step g).

e. The proportion of 83C RECs in the regional REC oversupply will be the same as the proportion of 83C RECs in the regional REC supply. Divide the total number of RECs produced by all 83C resources by the total number of RECs produced by all resources to yield the proportion of 83C RECs in the regional REC supply.

f. Multiply the result by the regional REC oversupply to determine the number of 83C RECs in the regional oversupply. Subtract this from the Regional REC oversupply to yield the non-83C REC oversupply.

g. Determine each state's share of the non-83C REC oversupply:

   - Each state's percentage share of the non-83C REC oversupply will be the average of its load share, its share of the 2020 REC oversupply allocation, and the ratio of non-83C RECs produced in the state to non-83C RECs produced in or imported into New England.
   - Multiply these state shares by the total non-83C REC oversupply to yield the number of non-83C oversupply RECs allocated to each state. To the non-83C RECs allocated to MA, add the 83C RECs in the regional oversupply to yield the total number of oversupply RECs allocated to MA.

h. Transfer RECs among states to achieve the total regional oversupply allocation determined in Step g. The transfer into (+) or out of (-) a state will be number of RECs allocated to it in Step g minus its surplus after the transfers of Step a.

4. Output 8 — GWSA compliance contribution (GHG Inventory Impact)

As the composition of energy generated within and imported into Massachusetts changes each year, one MWh of clean energy will offset a different quantity of emissions.

For the Base Case and each Proposal Case, the overall emission rate for the Inventory in a year will be calculated as pounds of CO2 emitted that year divided by MWh of energy consumed in Massachusetts that year. To express the GHG Inventory Impact of each Proposal Case in MWh, the decrease in metric tons CO2e relative to the Base Case is divided by the Base Case emissions rate (metric tons CO2e/MWh).

GHG emissions (Metric tons CO2e) are calculated as:

$$\textit{Emissions from Massachusetts generation} + \textit{Emissions attributed to electricity imports into Massachusetts from other NE states} + \textit{Emissions attributed to electricity imports from external control areas}$$

Emissions from generation in each NE state and New York, and the annual energy imported into NE from New York, are outputs of the Model. Emissions attributable to imports from New York into New England are calculated as the product of the emissions rate of the New York generation mix and the quantity of energy exported to NE, where the emissions rate is calculated as emissions from New York generation and energy imports divided by the sum of New York generation and energy imports. Emissions from imports from each external control area into NE or New York are calculated as the product of the quantity of imports from the external control area and a fixed emissions rate for the external control area.

For each NE state, generation adjusted for transfers among states and into NE is calculated as:[44]

$$\textit{Total generation in state} + \textit{Non-MA RECs assigned to MA} \ (\geq 0 \text{ for MA}, \leq 0 \text{ for other states}) + \textit{83D EAs assigned to MA} \ (\geq 0 \text{ for MA}, \leq 0 \text{ for other states}) + \textit{Millstone and Seabrook attributes assigned to MA} \ (\geq 0 \text{ for MA}, \leq 0 \text{ for other states}) + \textit{Seabrook attributes assigned to CT} \ (\geq 0 \text{ for CT}, \leq 0 \text{ for other states}) + \textit{Surplus RECs transferred into } (+) \textit{ or out of } (-) \textit{ state for RPS or MA CES compliance} + \textit{Transfers of RECs into } (+) \textit{ or out of } (-) \textit{ state to allocate regional REC oversupply}$$

Adjusted energy imports from or exports to each external control area are calculated as:

$$\textit{Energy import } (+) \textit{ from or export to } (-) \textit{ external control area} - \textit{RECs from area that are assigned to MA} - \textit{83D EAs from external area assigned to MA} - \textit{Transfers of RECs out of external area to allocate regional REC oversupply}$$

To calculate energy transfers from NE states into Massachusetts, i.e., energy imports to Massachusetts, each state's generation adjusted for transfers among NE states and into NE states from external control areas is compared to its load to determine whether the state has a surplus or shortfall. Generation from external control areas (i.e., imports into NE), as adjusted above, is considered available for transfer; adjusted exports from NE to New York are considered a

[44] Millstone attributes are assigned to Massachusetts to represent attributes reserved or retired in Massachusetts by the Massachusetts Municipal Wholesale Electric Company (MMWEC). Seabrook attributes are assigned to Massachusetts to represent attributes reserved or retired in Massachusetts by MMWEC, the Taunton Municipal Lighting Plant, and the Hudson Light & Power Department.

shortfall. The shortfalls and surpluses are tallied, and the share of total shortfalls attributable to Massachusetts is calculated. The energy transfer from a state or external control area into Massachusetts is then:

$$MA\ share\ of\ total\ energy\ shortfalls\ \times Energy\ transfer\ available\ from\ state/area \\ \times Ratio\ of\ total\ shortfalls\ to\ available\ transfers$$

Emissions attributed to energy imports into Massachusetts from each NE state are calculated as:

$$\frac{Emissions\ from\ generation\ in\ NE\ state\ \times\ Energy\ transfer\ from\ NE\ state\ into\ MA}{\begin{array}{c}Generation\ in\ NE\ state\ adjusted\ for\ attribute\ transfers\ to/from\ other\ NE\ states\\ and\ into\ NE\ state\ from\ external\ areas\end{array}}$$

Emissions attributed to energy imports into Massachusetts from each external control area are calculated as:

$$\frac{\begin{array}{c}Emissions\ from\ imports\ into\ Massachusetts\ from\ external\ control\ area\ \times\\ Energy\ transfer\ from\ area\ into\ MA\end{array}}{\begin{array}{c}Generation\ (energy\ imports) from\ area\ adjusted\ for\ attribute\ transfers\ from\ the\ area\\ into\ NE\end{array}}$$

C. PORTFOLIO EFFECT

When multiple Projects are run as a Portfolio, their benefits may not be additive. The above methodology for individual Proposals will also be applied to Portfolios to determine the direct and other benefits of Portfolios in Stage Three.

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Table 1. Biogenic and Non-biogenic Fuels

Non-Biogenic
bituminous coal
sub-bituminous coal
distillate petroleum
natural gas
non-biogenic component of municipal solid waste
Other
tire derived fuel
petroleum coke
residual petroleum
jet fuel
Kerosene
waste oil
Biogenic
landfill gas
biogenic component of municipal solid waste
black liquor
wood/wood waste solids
sludge waste

***Source**: Massachusetts Department of Environmental Protection, Greenhouse Gas Baseline, Inventory & Projection Appendix S: 2016 Emissions from Electricity Consumed in Massachusetts (https://www.mass.gov/files/documents/2016/11/rk/gwsa-appq.xls)*

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Table 2. State Loads (GWh)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
CT	29,159	29,136	29,173	29,317	29,369	29,540	29,667	29,776	29,889	30,019	30,188	30,351	30,569
MA	58,177	58,553	59,246	60,309	61,166	62,300	62,566	62,796	63,036	63,309	63,666	64,009	64,469
ME	12,457	12,741	13,121	13,583	14,038	14,571	14,633	14,687	14,743	14,807	14,891	14,971	15,079
NH	12,625	12,749	12,904	13,110	13,255	13,440	13,498	13,547	13,599	13,658	13,735	13,809	13,908
RI	8,056	8,101	8,195	8,328	8,449	8,601	8,638	8,670	8,703	8,740	8,790	8,837	8,901
VT	5,274	5,277	5,311	5,374	5,425	5,509	5,533	5,553	5,574	5,598	5,630	5,660	5,701
Total	125,748	126,557	127,950	130,021	131,702	133,961	134,534	135,030	135,545	136,131	136,899	137,636	138,627

	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
CT	30,763	30,978	31,152	31,361	31,578	31,861	32,113	32,379	32,662	32,949	33,293	33,660	34,036
MA	64,877	65,331	65,700	66,140	66,597	67,193	67,726	68,287	68,882	69,490	70,214	70,988	71,781
ME	15,174	15,280	15,366	15,469	15,576	15,716	15,840	15,972	16,111	16,253	16,422	16,603	16,789
NH	13,996	14,094	14,174	14,269	14,367	14,496	14,611	14,732	14,860	14,991	15,148	15,314	15,486
RI	8,957	9,020	9,070	9,131	9,194	9,277	9,350	9,428	9,510	9,594	9,694	9,801	9,910
VT	5,737	5,777	5,810	5,849	5,889	5,942	5,989	6,039	6,091	6,145	6,209	6,277	6,347
Total	139,504	140,479	141,272	142,219	143,203	144,484	145,630	146,836	148,116	149,422	150,979	152,643	154,349

Source: *Gross-PDR Annual Energy Forecast (Table from 83C III Base Case Assumptions) minus forecast of Behind-the-Meter Solar PV*

Table 3. EAs under Long-term Contract to Massachusetts EDCs (MWh)

Source Location	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
QC	9,394,318	9,394,318	9,394,318	9,420,478	9,394,318	9,394,318	9,394,318	9,420,478	9,394,318	9,394,318	9,394,318	9,420,478	9,394,318

Source Location	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
QC	9,394,318	9,394,318	9,420,478	9,394,318	9,394,318								

Source: *TCR analysis based on estimated 83D resource output*

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Table 4. Emission Rates for Imports from Canada (lbs. CO2e/MWh)

Emission Rates, lb CO2e/MWh	
Quebec	2.6
NB	573.2

Source: *Preliminary rates for 2019, Tables A13-5 and A13-6, Annex 13, "National Inventory Report 1990–2019: Greenhouse Gas Sources and Sinks in Canada," Environment Canada, 2021.* https://publications.gc.ca/site/eng/9.506002/publication.htm

Table 5. 2020 REC Oversupply Allocation

State	2020 REC Oversupply Allocation
Massachusetts	51.1%
Maine	45.2%
New Hampshire	0.5%
Vermont	1.7%
Rhode Island	1.0%
Connecticut	0.6%

Source: *NEPOOL 2020 Unsettled and Reserved Certificate State Regulator Reports, as summarized by Massachusetts DOER.*

Attachment B – Capacity Expansion for 83C III OSW projects

This section describes an issue TCR faced in the modeling of offshore wind proposals in previous iterations and provides a solution to be implemented in 83C III.

A. ISSUE WITH RUNNING INDIVIDUAL CAPACITY EXPANSIONS FOR EACH PROJECT.

The ENELYTIX capacity expansion module determines the optimal combination of retirements of existing capacity and additions of generic new capacity to meet resource adequacy and environmental constraints at least cost, i.e. the objective function, over the planning horizon. The model is set up to obtain the solution with a set precision. There are multiple feasible solutions to the capacity expansion problem within that precision level. As a result, small differences in input assumptions between scenarios, e.g. proposal cases, can have disproportionally large implications for the capacity expansion module's selection of generic new capacity additions, specifically their timing and composition.

In previous rounds of modeling for 83C TCR recognized that small differences in input assumptions between two similar Proposals, could result in significant differences in the capacity expansion module's selection of generic new capacity additions.

For example, a given proposal case had capacity additions from 2035 onward consisting of one 533 MW combined cycle (CC) unit and five 338 MW combustion turbine (CT) peaking units (1 CC + 5 CT solution). In contrast, an almost identical proposal had capacity additions from 2035 onward consisting of two 533 MW combined cycle (CC) unit and three 338 MW CT units. (2 CC + 3 CT solution).

- The input assumptions for those two Proposal Cases were nearly identical yet the capacity expansion module selected two different yet equally near-optimal capacity expansion solutions for each of them.
- The two different, yet equally near-optimal, capacity expansion solutions produce very different energy price results (LMPS), when dispatched in the Energy & Ancillary Services module (E&AS). All else being equal, a 2 CCs + 3 CTs solution will result in lower LMPs than a 1 CC + 5 CTs solution. As a result, the model will yield indirect price impact benefiting OSW project B for reasons that are an artifact of the model's algorithm not necessarily reflective of the real differences sought to be estimated.

TCR expects to continue to see small differences in input assumptions causing significant differences in the capacity expansion module's selection of generic new capacity additions for the 83C III Proposal Cases which will likely lead to outcomes that may have significant differences in energy price projections not necessarily reflective of the real differences sought to be estimated.

B. TCR PROPOSED SOLUTION

The capacity expansion module achieves two key objectives: 1) determining retirements and additions of generic new capacity and 2) developing projections of REC and CEC prices.

TCR proposes to use separate runs of the capacity expansion modules to meet each of those objectives. The general approach is similar to that used in 83C II however some modifications are made in view of the wider range of eligible bid sizes and timings

The capacity expansion models would be set up using the following steps:

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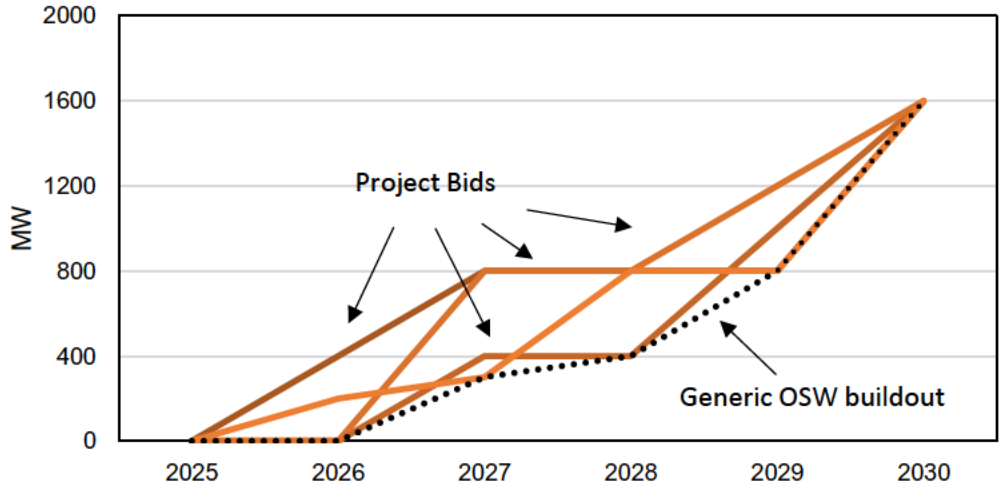
1. **Develop and run a "generic" capacity expansion to determine a common set of retirements and generic capacity additions for all 83C III Proposal Cases. The generic capacity expansion will rely on inputs based on the bids received.**
    a. Review and compare the OSW addition schedules of all proposals received and establish their pathways to 1,600 MW by 1/1/2030, adding proxies wherever necessary.
    b. Determine the schedule of offshore wind additions ("generic OSW buildout) that represents the lowest cumulative added OSW capacity in each year as illustrated in the below figure.



    c. Add generic proxy offshore wind units(quantity and timing) to match the generic OSW buildout identified in step b. These generic proxy offshore wind units will use the parameters assumed for the Proposal Case Proxy Units (capacity factor, hourly shape, aggregate point of interconnection). The capacity contribution of these generic proxy offshore wind units will equal the average capacity contribution of bids received.
    d. Run the capacity expansion model – the model will result in economic additions and retirements ("generic additions and retirements") of capacity in response to model requirements and system constraints (RPS, GWSA, resource adequacy etc.), as illustrated in the figure below.

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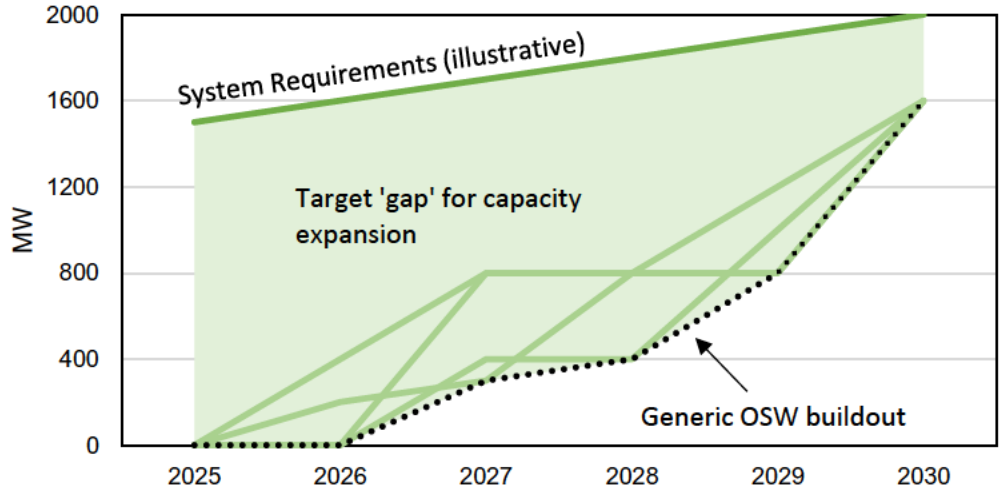

The purpose of running the capacity expansion against this generic OSW buildout is to ensure the 'gap' presents a conservative scenario of year-on-year offshore wind availability.

2. **Develop and run proposal specific capacity expansion models to calculate REC, CEC and other inputs to the production cost (E&AS) model. This run will inherit the generic additions and retirements from the generic capacity expansion run.**

   e. All generic additions and retirements from previous expansion run are held in place across all proposal cases. The proposal cases are prevented from making any incremental capacity decisions.

   f. The quantity, timing, and mix of capacity in the system resulting from the generic capacity expansion ensures no shortfalls in supply exist in any of the proposal cases. Proposal cases will likely bring capacity online earlier than the generic OSW buildout potentially resulting in excess capacity prior to converging to 1,600 MW in 2030 as seen in the illustration below. Surplus capacity over the short term will not adversely affect REC and CEC prices, or other parameters that are used from this run in the production cost models.

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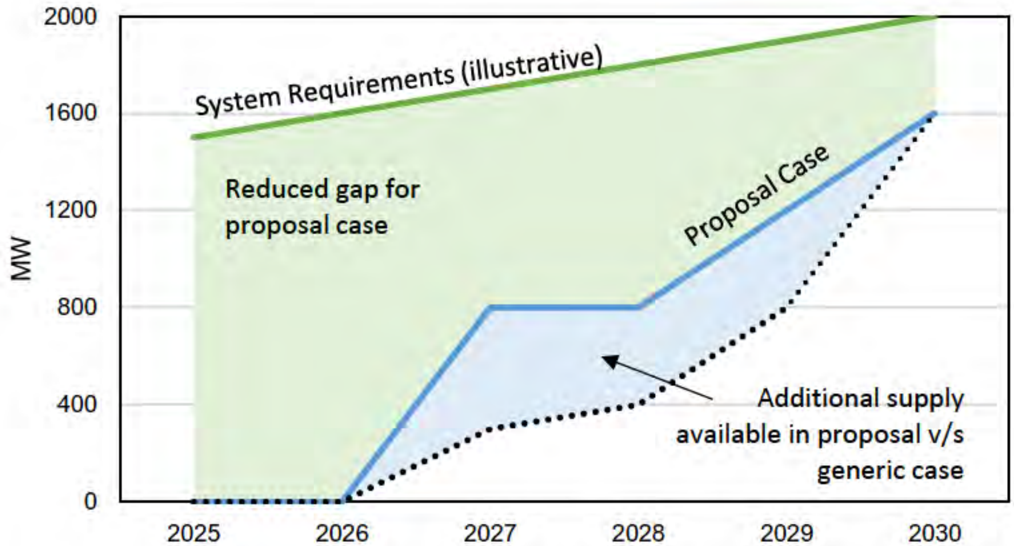

g. Run the proposal capacity expansion model to calculate the REC and CEC prices.

3. Run the 25-year production cost model for each proposal case using the results from the proposal case run.

Attachment C – Winter Fuel Switching Methodology

To estimate the impact on market operations and incremental CO2 emissions resulting from dual-fuel unit switching from gas to fuel oil on winter days with high gas prices TCR has developed an approach to modeling that switching. That approach involves the following key steps:

A. Estimate the number of days when switching from gas to oil is assumed to occur in the winter period (December to February) each year based on historical data. TCR reviewed historical prices for No.2 Distillate fuel oil (DFO) to identify days when the DFO price dropped below the price of natural gas on average over several years. take an average of that over several years[45.]

B. Review daily gas burn quantities during winter months from the MA 83C II cases and develop a 'gas burn limit' such that the number of days in the simulation in which the gas burn exceeds the limit (on average over the evaluation period) is equal to the assumed number of days of fuel switching identified in step 1 above.

C. Impose the gas burn limit on all gas-fired power plants over the winter period for all years run in the model. The ENELYTIX modeling system will enforce this constraint by switching dual fuel generators to their secondary fuel and/or shift generation to non-gas based fuel after the limit is reached.

The impact of running on fuel oil will be reflected in the LMPs and CO2 emissions during the winter period and is consistent with historical price increases during the winter period in ISO-NE.

[45] TCR did not estimate the number of fuel switching days based on projections of gas prices and fuel prices as these projections were not sufficiently granular for the analysis.

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A. ESTIMATING NUMBER OF FUEL SWITCHING DAYS EACH YEAR

In order to determine the number of days that the price of natural exceeded the price of fuel oil, TCR reviewed historic prices over a ten-year period for the following fuels:

- Algonquin Gate Natural Gas Spot Price46, Daily, Nominal Dollars per MMBTU
- New York Harbor No.2 Fuel Oil[47] (Distillate Fuel Oil / DFO), Monthly, Nominal Dollars per Gallon[48]

Figure C-1 provides a summary of the reviewed fuel prices in Nominal $/MMBTU with each vertical gridline representing the first day of the calendar year. TCR assumed that the fuel oil prices that are available weekly are held at the same price over the week, and that the gas prices on days for which there were no reported prices were equal to prices reported for the preceding day.

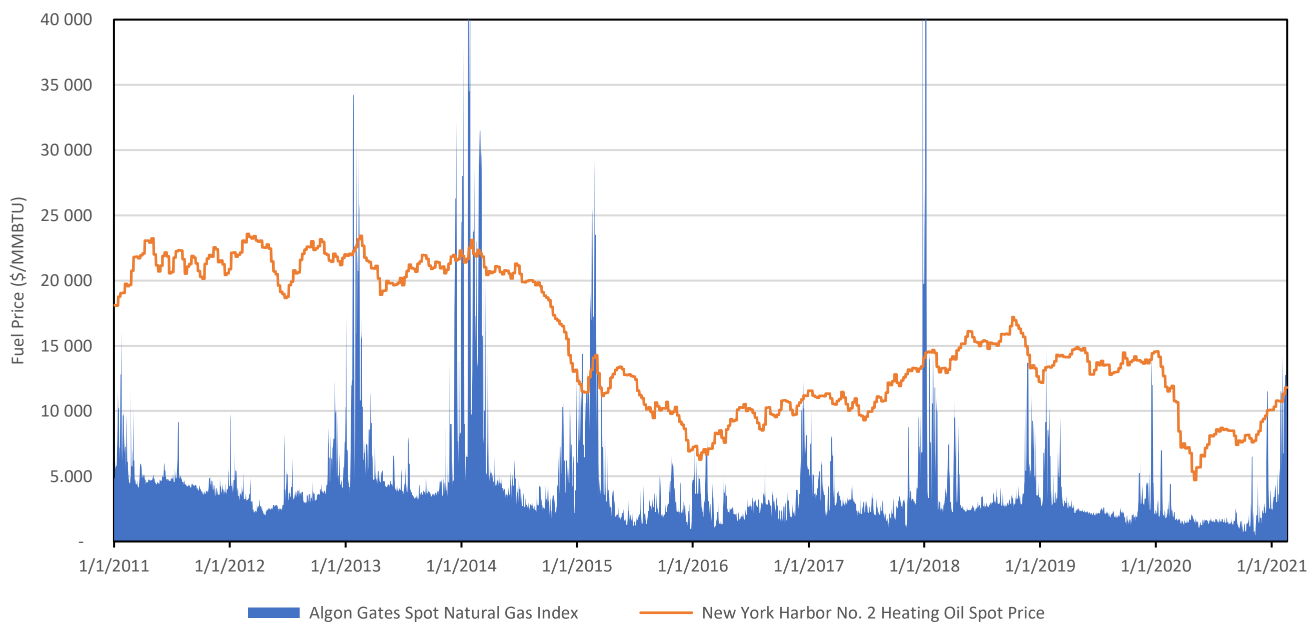

Figure Error! No text of specified style in document.**-1. Graph of historical fuel prices**

TCR determined the aggregate number of days in each December, January, February period, ("winter period"), on which the gas spot price at the Algonquin City Gate exceeded the price of No.2 Fuel Oil (Distillate Fuel Oil, or DFO).

TCR developed a representative number of days-per winter period ("fuel switching days") which estimates of the number of days in each winter period that dual-fuel generators are expected switch from natural gas to their respective secondary fuels. This estimate is developed based on a historic analysis of daily fuel prices during the winter period where the price of Natural Gas exceeded that of fuel oil. It is assumed that dual-fuel generators would have economically switched to burning fuel oil on these days.

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[46] S&P Global (https://platform.marketintelligence.spglobal.com/)

[47] EIA / Thomson Reuters (https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=EER_EPD2F_PF4_Y35NY_DPG&f=M)

[48] 1 Gallon No.2 = 138.690 BTU, 1 Gallon No.6 = 149,690 BTU (https://www.ct.gov/deep/lib/deep/energy/energyprice/energy_conversion_factors.pdf)

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An analysis of the past ten winter periods resulted in an average of 11 days per year as indicated in Figure C-2.

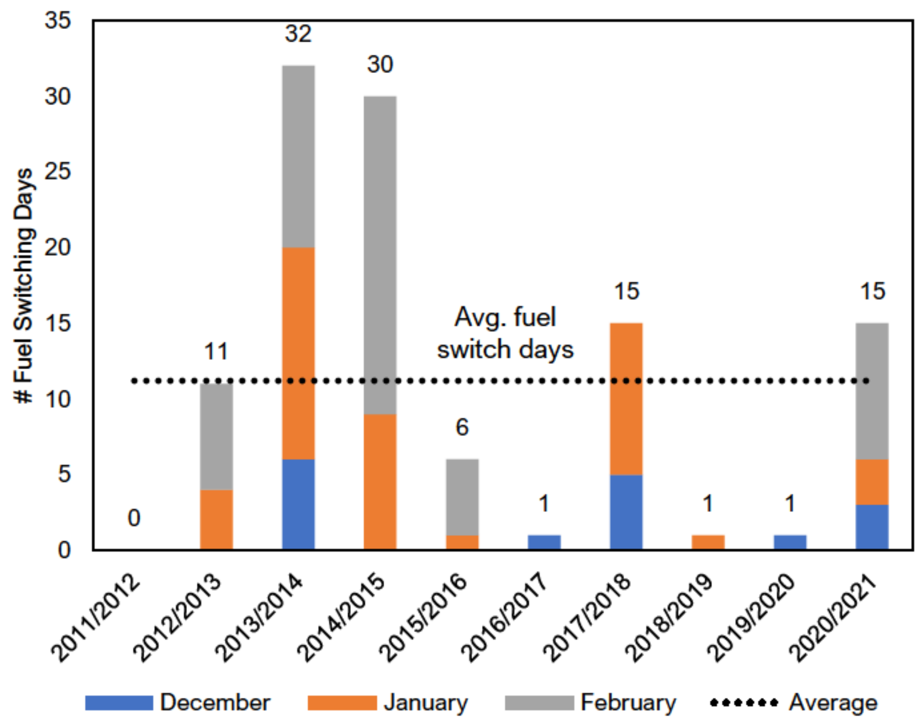

Figure Error! No text of specified style in document.**-2. Graph of historical fuel prices**

ISO-NE CELT 2021 lists 7.1 GW dual-fuel generators having their primary fuel as Natural Gas and secondary fuel as fuel oil[49].

B. DEVELOP DAILY GAS BURN LIMIT

Having developed a value for assumed fuel switching days per winter period, TCR developed an assumed limit on how much gas would be consumed daily ("daily gas burn limit") in MMBtu/day which is used to trigger dual-fuel gas-fired generators to switch from burning natural gas to fuel oil once the limit is exceeded.

TCR developed the daily gas burn limit from the results of its ENELYTIX modelling of the New England electricity market for the top ranked case from MA 83C II ("Reference Case"), as that case most closely represents the generation mix TCR expects for the 83C III Base Case.

The daily gas burn limit is calibrated with the objective that the number of days in the winter period during which dual-fuel generators would switch in the evaluation period matches (on average) the number of days the switching would have occurred historically (on average).

The burn limit is calculated iteratively through the following steps:

1. Assume a daily burn limit, e.g. 820,000 MMBTU/day

[49] All units except West Springfield 3 113 MW ST unit list DFO as their secondary fuel. This exception is ignored.

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2. Using data from the ENELYTIX model, calculate the number of days in each winter period where the burn limit was exceeded
3. Average the number of days exceeded over all of the years available in the Reference Case to arrive at an overall average number of days exceeded
4. Compare the value in step 3 against the target fuel switching days calculated, i.e. 11 days. Adjust the value in step 1 and repeat steps 2 to 4 until the number of days match.

The resulting daily gas burn limit that meets the target switchover days is 929,000 MMBTU / day.

Figure **Error! No text of specified style in document.**-1 plots the calculated daily gas burn limit and the average daily gas burn quantities by month in each of the three winter month periods from the Reference Case. Notable increases are seen in the outer years where retiring nuclear capacity is replaced by gas fired generation.

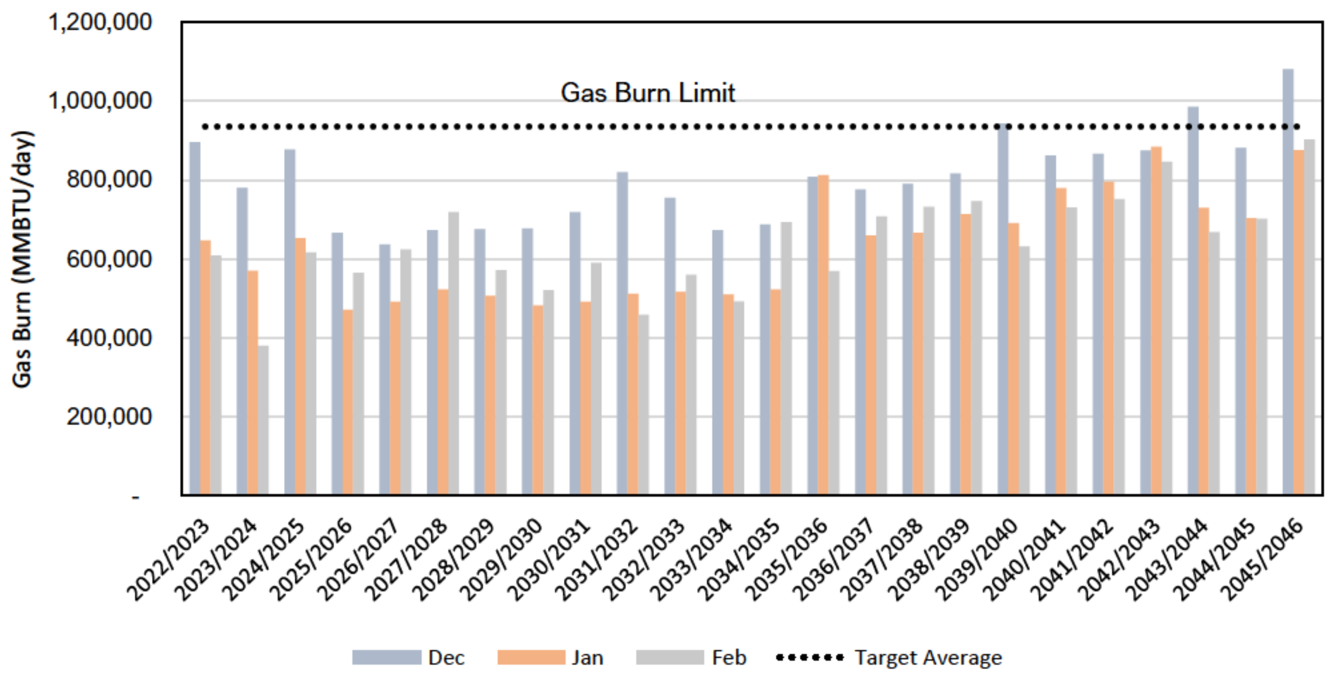

Figure Error! No text of specified style in document.**-1. Gas Burn Limit Analysis, Reference Case**

Figure **Error! No text of specified style in document.**-2 presents the number of days in each winter period on which the projected daily gas burn exceeds the daily gas burn limit in historical years as well as the reference case.

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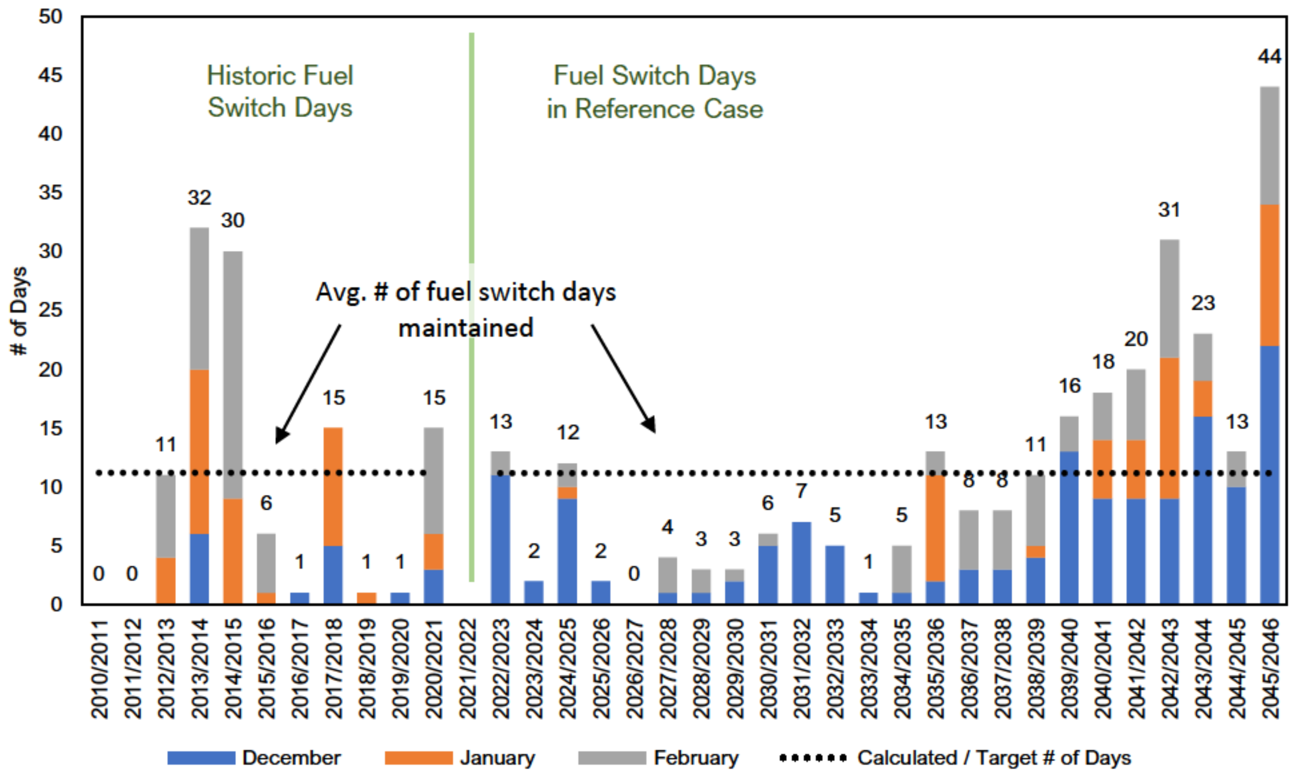

Figure Error! No text of specified style in document.**-2. Fuel switch days over the winter period for historic (days where price of NG exceeds DFO) and reference case (days where the daily gas burn exceeds the burn limit)**

C. IMPOSE GAS BURN LIMIT ON ALL GAS FIRED GENERATORS

The daily gas burn limit is imposed as a modeling constraint on all gas fired generation in ISO-NE during the winter period across all modeled years. A scarcity premium is added to ensure solution feasibility and prevent load shedding at extreme prices. The constraint and scarcity premium would economically switch dual-fuel units to fuel oil and/or increase the dispatch of non-gas generation, once the gas limit is reached.

The extent of impact due to the fuel-switch will depend on the frequency of occurrence, however the constraint is expected to drive higher electricity prices in the winter period as fuel oil sets the price more often. The fuel switch also increases the emissions from generators that result in added emission compliance costs as well.

The resulting increase in prices during the winter period is consistent with behavior seen historically in ISO-NE.

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C.2: Addendum to Protocol

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Protocol Addendum

This document serves as an addendum to the Protocol for 83C III Quantitative Metric Calculations, Stage 2 document ("Quantitative Protocol"); it provides additional details and amendments to the evaluation process that were not documented or finalized prior to the opening of 83C III bids. Any and all changes were made with approval from the full Evaluation Team.

1. Change in Indirect REC Metrics to account for ACPs

Section 9.B.2 of the Quantitative Protocol describes the calculation of Indirect benefit metrics relating to RPS and CES compliance costs, which are calculated as follows:

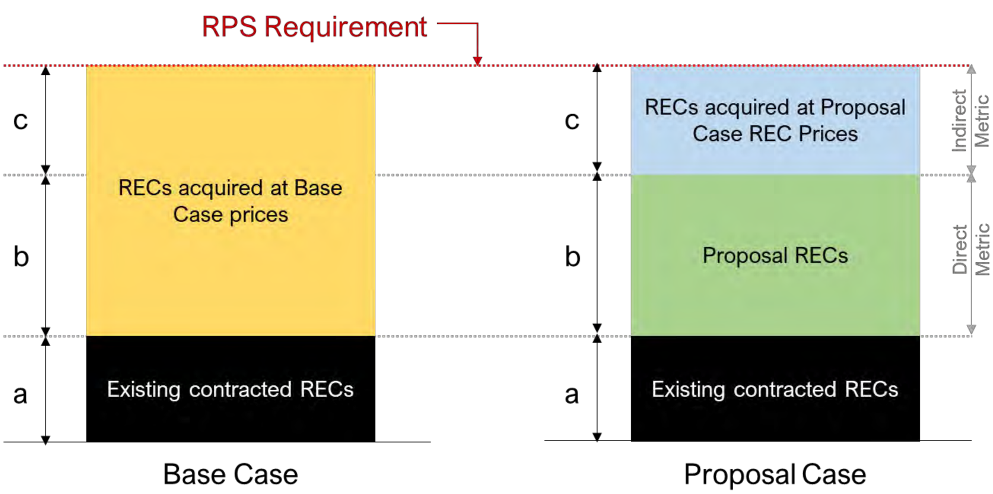
2. Impact on RPS and/or CES compliance costs paid by ratepayers in the Commonwealth

a. For the Proposal Case, calculate the annual quantity of Class 1 RECs that will be acquired from the market to meet the RPS / CES requirement associated with EDC distribution service. This quantity equals the total quantity required for compliance minus the aggregate quantity from EDC contracts in the Base Case and minus the Proposal and Proxy RECs.

b. Calculate the REC market price change under the Proposal Case ($/MWh) as the REC market price in the Base Case minus the REC market price in the Proposal Case.

c. Calculate the REC market price change impact of the Proposal as the annual quantity of Class 1 RECs that will be acquired from the market, from B.2.a, multiplied by the REC market price change from B.2.b starting from the contract Proposal start date through the end of the study period, 2050.

The above calculation assumes that any REC shortfall identified in step 2.a above would be met through purchases of RECs at market prices. The benefit is then valued as the product of the reduction in REC prices from the Base Case to the Proposal Case and the quantity of RECs purchased, as illustrated in Figure 1 below.



Direct Metric = b x Base Case REC Price

Indirect Metric = c x (Base Case REC Price – Proposal Case REC Price)

Figure 1 Indirect REC metric without ACPs

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83C III Stage 2 Evaluation Protocol DRAFT

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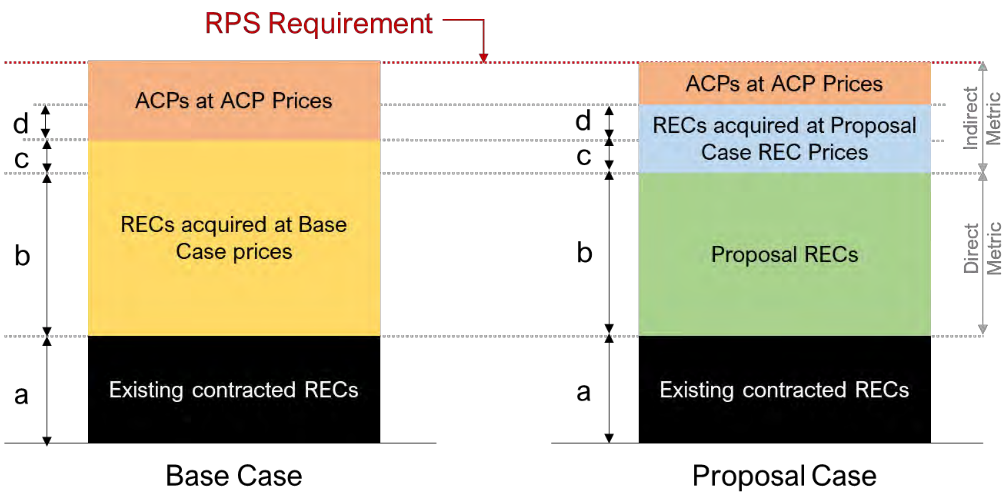
Recent changes in MA regulations[1] result in MA ACP prices being tied with those of CT as the lowest-priced in New England ($40/MWh in nominal terms). For that reason, the benefit metrics calculations assume that regional REC deficiencies will be consolidated in these two states, instead of solely in CT, as was the case in the GHG and benefits analysis for previous 83C procurements. The result is that MA RPS compliance is met through a combination of market REC purchases and ACPs. Differences in prices between ACPs and market REC prices as well as differences in quantities of ACPs between the Proposal Case and Base Case require a more comprehensive accounting of indirect REC benefits than the methodology described in the Quantitative Protocol. Figure 2 below illustrates this accounting.



Direct Metric = b x Base Case REC Price

Indirect Metric = c x (Base Case REC Price – Proposal Case REC Price) +

d x (ACP Price – Proposal Case REC Price)

Figure 2. Indirect REC metric with ACPs

The revised metric used for evaluation is as follows:

2. Impact on RPS and/or CES compliance costs paid by ratepayers in the Commonwealth

a. For the Proposal Case, calculate the annual quantity of Class 1 RECs that will be acquired (purchased) from the market to meet the RPS / CES requirement associated with EDC distribution service. This quantity equals the total quantity required for compliance minus the aggregate quantity from EDC contracts in the Base Case minus the Proposal and Proxy RECs, minus the quantity of ACPs used for compliance (quantity "c+d")

[1] 225 CMR 14.00: Renewable energy portfolio standard - Class I, https://www.mass.gov/regulations/225-CMR-1400-renewable-energy-portfolio-standard-class-i

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b. *Calculate the quantity of Base Case ACPs displaced by Proposal Case market REC purchases as the annual quantity of ACPs in the Base Case minus the annual quantity of ACPs in the Proposal Case (quantity "d")*

c. *Calculate the Quantity of Base Case market REC purchases displaced by Proposal Case market REC Purchases in the Proposal case by subtracting the quantities obtained in step B.2.a by the quantities obtained in B.2.b. (quantity "c")*

d. *Calculate the price savings associated with avoided ACPs ($/MWh) as the MA ACP price minus the REC market price in the Proposal Case.*

e. *Calculate the REC market price change under the Proposal Case ($/MWh) as the REC market price in the Base Case minus the REC market price in the Proposal Case.*

f. *Calculate the REC market price change impact associated with avoided ACPs as the annual quantity of Base Case ACPs displaced by Proposal Case REC purchases, from B.2.b, multiplied by the price savings associated with avoided ACPs from B.2.b.*

g. *Calculate the REC market price change impact associated with purchased RECs as the Base Case REC purchases displaced by Proposal Case REC Purchases in the Proposal, from B.2.c, multiplied by the REC market price change from B.2.e.*

h. *Calculate the total REC market price change impact by adding the annual values obtained from step B.2.f and B.2.g above, starting from the contract Proposal start date through the end of the study period, 2050.*

2. Update to Winter Fuel Switching limit

Attachment C to the 83C III Quantitative Protocol describes the methodology used to establish a daily gas burn limit (or 'gas cap') which is imposed in the model during the winter months to replicate the effect of natural gas shortages and price spiked due to dual fuel generators switching to fuel oil. The daily burn limit was estimated to be 929,000 MMBTU / day.

During the analysis, it was observed that imposing the estimated daily burn limit resulted in significantly higher fuel switch frequencies than was expected from the model. Upon review, this difference was attributed to differences in input data, assumptions and modeling periods between the 83C II model that was originally used to calibrate the limit and the model being used for the 83C III analysis. It thus became necessary for the Evaluation Team to investigate the gas burn limit to determine whether it was unrealistically low.

To do this, the Evaluation Team attempted to reconcile the differences in fuel switch frequencies by consulting with an expert on the natural gas limitations in New England, recalculating the daily burn limit by running the 83C III model for four representative years and using those results to converge on an estimated new limit consistent with the expert's input such that the fuel switch frequencies would lie within expected and reasonable values. This incremental analysis took into consideration the following:

- The expert's input regarding a realistic level of gas availability during the winter season in New England.
- An approximate target 11 days of fuel switch per year on average based on the analysis.
- An approximate 30-day annual limit on fuel switch days based on an assessment of fuel oil capacity limits indicated by ISO-NE and discussed with the Evaluation Team.
- Daily gas burn limit quantities that will result in no significant additions to existing gas pipeline infrastructure. There will be a single natural gas cap applied across all years that is consistent with historic winter electric generation natural gas consumption.

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- Recognizing that significant nuclear capacity would be replaced by gas fired generation in the outer years leading to fuel switch frequencies that may be higher than the limits discussed above.

Figure 3 through Figure 5 below illustrate the frequency at which the daily burn limit is exceeded in the winter months using the 83C III model reporting results for representative years. The charts are provided for the following daily burn limits:

1. **929,000 MMBTU/day:** Original limit calculated in the Quantitative Protocol.
2. **1,200,000 MMBTU/day**: this limit approximates the 11-day fuel switch per year assumption that TCR calculated based on historical fuel price data for the initial years of the modeling prior to nuclear retirement.
3. **1,620,000 MMBTU/day**: this limit achieves a maximum 30-day switch by 2045, however this results in almost no switching in prior years.

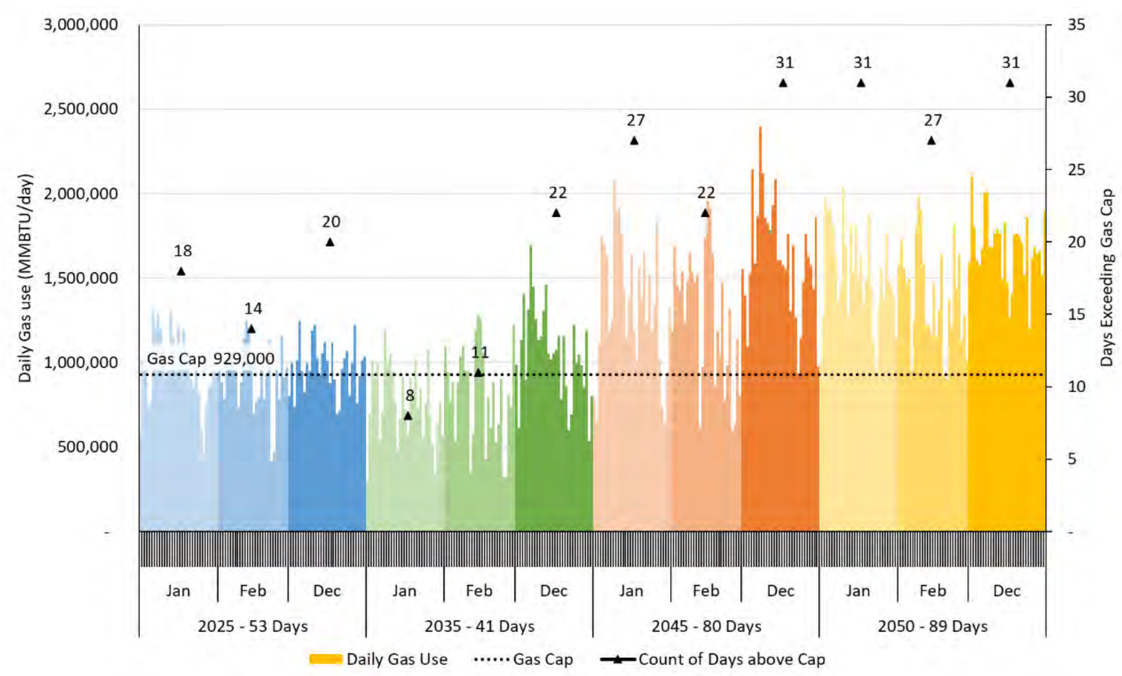

Figure 3. Gas Cap Analysis, Gas Cap = 929,000 MMBTU

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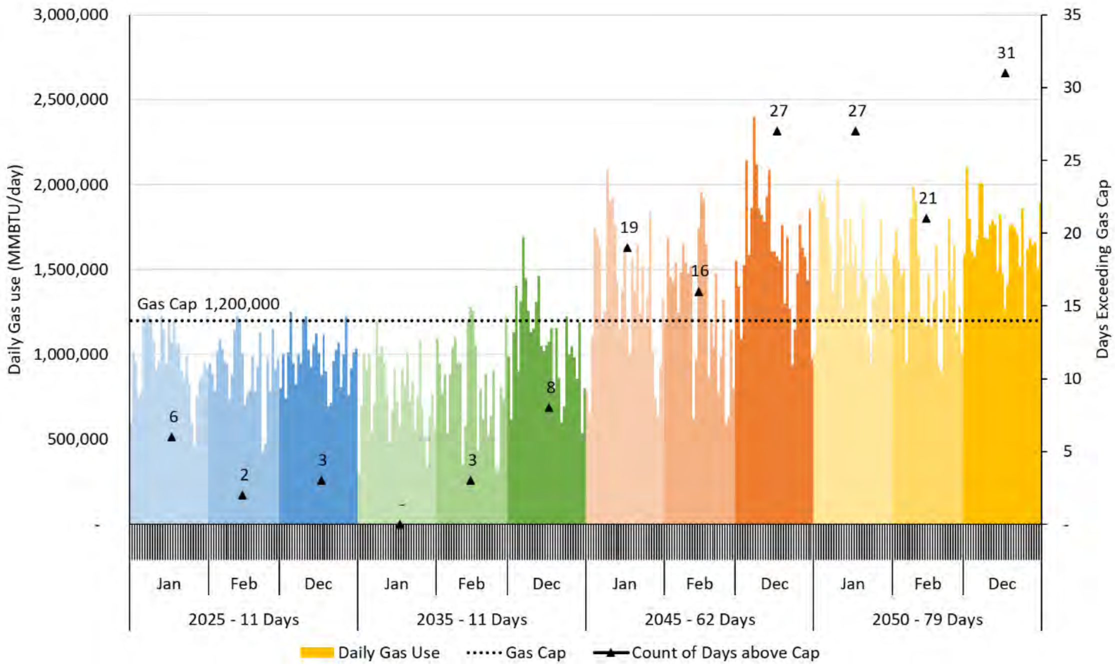

Figure 4. Gas Cap Analysis, Gas Cap = 1,200,000 MMBTU

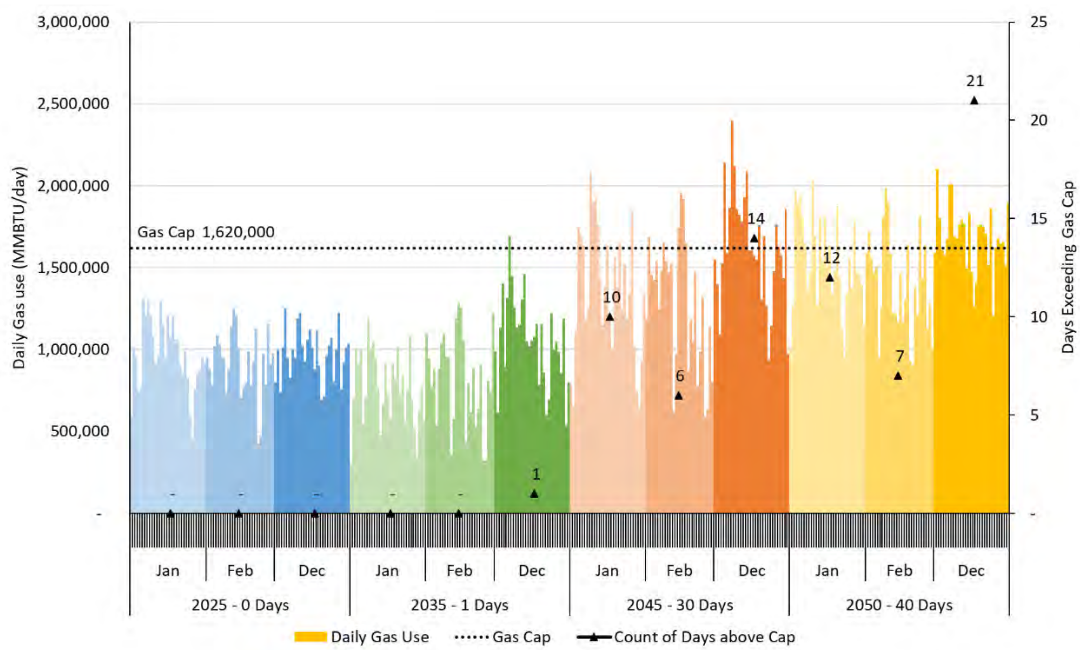

Figure 5. Gas Cap Analysis, Gas Cap = 1,620,000 MMBTU

The analysis highlights the issues of assuming a constant gas burn limit through the evaluation period which sees the retirement of nuclear in the outer years driving up gas use. Consistent with the input provided by the gas limitation expert, the Evaluation Team decided to use an assumed daily gas burn limit

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of 1,200,000 MMBTU/day which results in non-zero fuel switches in the early years and a reasonable switch frequency through 2035. This value also remains within the limits of historic winter gas use of approximately 1,300,000 MMBTU/day.

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C.3: GWSA Calculation Methodology

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The Global Warming Solutions Act (GWSA)

The Global Warming Solutions Act (GWSA) requires the Commonwealth to reduce GHG emissions 80 percent below 1990 levels by 2050. In 2010, the Secretary of Energy and Environmental Affairs (EEA) set a 2020 limit on emissions at 25 percent below 1990 levels and published the first Clean Energy and Climate Plan (CECP)[1], identifying the policies necessary to achieve these goals. In 2015, EEA released an updated 2020 CECP.[2] The 2030 CECP, to be published by EEA in 2020, will identify the 2030 limit on emissions and identify the policies necessary to achieve the new limit.

The 2020 CECP 2015 Update lists three policies for Electricity Generation and Distribution and their associated anticipated 2020 reductions from full policy implementation: Coal-Fired Power Plant Retirements, Renewable Portfolio Standard (RPS), and Clean Energy Imports. Since the publishing of the 2020 CECP 2015 update, the referenced Clean Energy Standard (CES) was implemented by the Massachusetts Department of Environmental Protection (MassDEP) with anticipated reductions for Electricity Generation and Distribution. Additionally, MassDEP promulgated regulation 310 CMR 7.74 Reducing CO2 Emissions from Electricity Generating Facilities in 2017 to set an annual declining limit on CO2 emissions from large electric generating facilities in the Commonwealth. As part of the GWSA 10-year Progress Report published by EEA in 2018, Clean Energy Imports is renamed to Clean Energy Procurements to reflect the procurement of hydroelectricity resources and offshore wind, both of which will be online in the 2020s and help meet the RPS and CES requirements.[3]

The Massachusetts Department of Environmental Protection's (MassDEP) Greenhouse Gas Inventory (Inventory) is the database used to track the state's progress towards the GWSA target.[4] As required by the GWSA, the Inventory accounts for all greenhouse gas emissions associated with the state's electricity consumption, meaning that if the electricity is used within the state, the Inventory accounts for associated emissions even if the electricity was generated in another state. Massachusetts is a net importer of electricity, meaning the state consumes more electricity than Massachusetts generates. Imported electric sector emissions are calculated considering the generation of each New England state and the transfer of renewable energy certificates for states' environmental compliance. All the above policies included in the 2020 CECP 2015 Update impact the emissions as accounted for in the Inventory through the emissions from power generators and the transfer and retirement of renewable energy and clean energy certificates for Massachusetts and regional renewable and clean energy portfolio standards.

[1] Massachusetts Clean Energy and Climate Plan for 2020; https://www.mass.gov/files/documents/2016/08/sk/2020-clean-energy-plan.pdf

[2] Massachusetts Clean Energy and Climate Plan for 2020, 2015 Update; https://www.mass.gov/files/documents/2017/01/uo/cecp-for-2020.pdf

[3] Global Warming Solutions Act 10-Year Progress Report; https://www.mass.gov/files/documents/2019/04/02/GWSA-10-Year-Progress-Report.pdf

[4] MassDEP Emissions Inventories, https://www.mass.gov/lists/massdep-emissions-inventories and *Statewide Greenhouse Gas Emissions Level: 1990 Baseline and 2020 Business As Usual Projection Update*, https://www.mass.gov/files/documents/2016/11/xv/gwsa-update-16.pdf

GWSA in the Quantitative Evaluation

The GWSA methodology in the Quantitative Evaluation consists of two parts, approximating a proposal's incremental impact on emissions reductions (in MWh) and assigning those emission reductions value (in dollars) to determine a proposal's total $/MWh benefit towards increased GWSA compliance as compared to a base case.

Approximating the Emission Reduction Impact

Clean energy policies and their associated emission reductions are included in the results of the analytic tool ENELYTIX licensed by Tabors Caramanis Rudkevich (TCR) to perform economic analyses of a Base Case and each proposal case. TCR uses ten major categories of input assumptions to model the 83C Base Case and each of the Proposal / Portfolio Cases in ENELYTIX. They were Generating Unit Capacity Additions, Transmission, Load Forecast, Installed Capacity Requirements, RPS Requirements, Massachusetts CES and cap on Carbon Emissions, Emission Allowance Prices, Generating Unit Retirements, Generating Unit Operational Characteristics and Fuel Prices. These input assumptions therefore account for all major Electricity Generation and Distribution policies as listed in the 2020 CECP 2015 Update and 2018 GWSA Progress Report, although may not represent their full implementation. For example, compliance with the Massachusetts RPS in the ENELYTIX modeling may be met with a Class I REC or with an Alternative Compliance Payment (ACP), the latter having no associated emission reduction. Each Proposal Case will assume the EDCs ultimately acquire 800 MW of new offshore capacity consisting of the MW from the bid they select in this solicitation and the MW from a proxy unit to be acquired from a future solicitation.

The results of the economic analyses of a Base Case and each proposal case are then input into the GHG Inventory Worksheet to measure the incremental contribution of each Proposal /Portfolio towards meeting the Massachusetts GWSA relative to the 83C Base Case. The incremental contribution over the modeled time period will likely not equal the project's full emission reduction contribution because the Proposal Case is compared to the Base Case which will also have additional emission reductions post 2019. For example, the ENELYTIX input assumes a cost to increasing RPS compliance in the Base Case, incentivizing additional renewable generation. Incremental contribution from the Proposal can come from greater compliance with policies such as the RPS by avoiding ACP payments or from exceeding the policy compliance in the Base Case through greater reductions in annual emissions (in metric tons of CO2 equivalent) of grid energy generated in Massachusetts and/or imported into Massachusetts or greater number of RECs that may be retired in Massachusetts or other states.

The ENELYTIX modeling report describes the ENELYTIX input and modeling assumptions in detail.

Assigning the Emission Reduction Impact Value

As part of the calculation of direct benefits, the Quantitative Evaluation includes the "Comparison of the price of any Renewable Portfolio Standard ("RPS") Class I eligible RECs under a contract to: i. the avoided cost with the project not in-service if the RECs are to be used for RPS and Clean Energy Standard ("CES") compliance by the Distribution Companies or Massachusetts retail electric suppliers, and ii. their projected market prices with the project in-service if the RECs are projected to be sold." As part of this calculation, TCR determines the MA

Class 1 RPS and MA CES compliance obligation that could be met with the Class I RECs from the Proposal. If proposal RECs can be used for MA Class 1 RPS and MA CES compliance obligations, they are assigned direct annual dollar benefit equal to the avoided cost of meeting that obligation at the market price of Class 1 RECs/CECs in the Base Case.

Additionally, proposal RECs that are not retired for RPS or CES compliance or sold into the market may have an impact on GWSA compliance and should be valued through the indirect benefit, calculated as the "Impact of the Proposal on the Commonwealth's ability to meet Global Warming Solutions Act (GWSA) requirements in excess of compliance with the RPS and the CES."

Including both the REC compliance benefits and the indirect incremental GWSA compliance benefits in the Quantitative Evaluation, ensures that each environmental attribute or emission reduction in MWh is assigned a single value for its contribution to GWSA compliance and to ensure the value of each MWh of emission reduction is not double counted.

APPENDIX D:
Proposal and Portfolio Evaluation Process

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Evaluation of Proposals and Portfolios

This document provides additional detail on case specific input assumption and methodological adjustments that were used in the evaluation process for 83C III Proposals and Portfolios.

1. Introduction

Each Proposal and Portfolio Case was analyzed based on a standardized evaluation process developed prior to the opening of bids and documented in the 83C III Quantitative Protocol consistent with the approach used for all prior 83C proposal evaluations. Modifications to this evaluation process that were found to be necessary after bid opening were developed by the full Evaluation Team, in consultation with the IE. These are documented in the Protocol Addendum. The standardized and modified processes are provided as Appendix C.1 and Appendix C.2 to the TCR Evaluation Report respectively.

The evaluation process involved the development of individual Proposal/Portfolio case models that were independent[1] of each other and incremental to a common baseline[2]. The resulting projections of energy, price and other attributes from the respective Proposal/Portfolio model simulations combined with the 83C III Base Case projections were used to calculate quantitative metrics and scores.

83C III encountered a set of complexities in evaluating offshore wind Proposal/Portfolios that were not faced in previous solicitation rounds, due to factors including ongoing ISO-NE interconnection studies,[3] priorities in queue positions, and their impacts on the size, timing and interconnection points of bids received.

Furthermore, upon review of bids, the Evaluation Team recognized that certain Proposal and Portfolio cases required additional input assumptions and/or modifications to their evaluation processes to reflect the specific character of the bids to ensure their accurate representation, and to ensure a fair and consistent evaluation. Certain sensitivity cases were also requested by members of the evaluation team to support the Evaluation Team's analyses.

Section 2 of this document identifies all Proposals and Portfolios evaluated in Round III, and identifies all such process modifications that were applied in their evaluation. Section 3 provides further details on the implementation of those modifications.

1 Each Proposal sponsored by the bidder was developed into an independent and separate Proposal Case model. Portfolio Case models are separate but include multiple proposals as selected by the Evaluation Team and take into account specific interactions between proposals, if any.

2 The 83C III Base Case model provides a counterfactual scenario where the EDCs do not procure 1,600 MW of offshore wind. This establishes the baseline for all evaluations. The fundamental difference between the Base Case and the Proposal / Portfolio Case model inputs are the inclusion of offshore wind units as bid along with their proposed onshore transmission upgrades.

3 https://www.iso-ne.com/static-assets/documents/2021/04/cape_cod_resource_integration_study_march_2021_preliminary_results_summary_non_ceii_version.pdf

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2. Summary of Proposal / Portfolio Evaluation Process Modifications

Proposal Identifier	Type	A. Unmodified Protocol Assumptions		B. Modifications in model assumptions based on Bid Specifics				C. Modifications Supporting Sensitivity Analyses	
		A.1. Use of Proxy Offshore Wind Unit	A.2. Change in POI of 83C II Contract for Proposals at Cape	B.1. Inclusion of As-bid Non-Contracted capacity	B.2. Scale Down of Offered Capacity	B.3. Use of As-bid Alternative POI	B.4. Change in POI and COD of 83C II Contracts	C.1. Uses 'Adjusted' Quantitative Metrics	C.2. Alternative Qualitative Scores
[redacted]									

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83C III Evaluation of Proposals and Portfolios

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Proposal Identifier	Type	A. Unmodified Protocol Assumptions		B. Modifications in model assumptions based on Bid Specifics				C. Modifications Supporting Sensitivity Analyses	
		A.1. Use of Proxy Offshore Wind Unit	A.2. Change in POI of 83C II Contract for Proposals at Cape	B.1. Inclusion of As-bid Non-Contracted capacity	B.2. Scale Down of Offered Capacity	B.3. Use of As-bid Alternative POI	B.4. Change in POI and COD of 83C II Contracts	C.1. Uses 'Adjusted' Quantitative Metrics	C.2. Alternative Qualitative Scores
[redacted]									

REDACTED

3. Explanation of Evaluation Process Modifications

A. ORIGINAL PROTOCOL PROCESSES

1. Use of Proxy Offshore Wind Unit

Proposals and Portfolios whose total contracted capacity was less than 1,600 MW included Proxy offshore wind unit(s) in the Proposal/Portfolio case model that brought the capacity to 1,600MW based on a consistent set of assumptions. The objective of the Proxy unit was to ensure that all Proposals/Portfolios were evaluated at a 1,600 MW level, in order to facilitate accurate comparability.

Proxy units are included assuming the equivalent technical characteristics of the Project units for the quantitative metric calculations. Refer to Section 5 of the Quantitative Protocol for detailed Proxy assumptions.

2. Change in POI of 83C II Contracts due to Proposals connecting to Cape Cod

In order to ensure a fair evaluation, Proposals and Portfolios that proposed using an ISO-NE Interconnection Queue position with priority over that relied upon by Mayflower's 83C II PPAs move the second tranche of the 83C II contract away from the 345 kV substation at Falmouth (Cape Cod), which is the point of interconnection assumed in the 83C III Base Case. This was done to reflect interconnection limitations on Cape Cod recently identified by ISO-NE studies without unduly penalizing the bids with Interconnection Queue priority.

Proposals and Portfolios that meet specific criteria described in Section 5 of the Quantitative Protocol 'Special handling of proposals connecting to Cape Cod' have the point of interconnection of the second tranche of the 83C II offshore wind contract moved from the Falmouth 345 kV substation to a distributed node that spreads energy across the SEMA-RI energy areas.

B. MODIFICATIONS IN INPUT ASSUMPTIONS BASED ON CHANGED CIRCUMSTANCES AND SPECIFIC BID CHARACTERISTICS

1. Inclusion of As-bid Non-contracted Capacity

Proposals and Portfolios that include either of the two [redacted] bids also include additional quantities of offshore wind that were proposed in the respective bids but were not included in the contracted capacity offered to the EDCs.

- [redacted]
- [redacted]

In order to accurately analyze these proposals as bid, the Evaluation Team included all as-bid non-contracted additional offshore wind in the portions of their respective Proposal/Portfolio case models impacting indirect customer benefits, and treated this non-contracted capacity as merchant-based offshore wind capacity. The Evaluation Team specifically confirmed this aspect of these [redacted] Proposals with the bidder through specific questions and answers. This approach is consistent with the treatment of the Proposals of the other bidder in the RFP, [redacted]

REDACTED

It is noted that non-contracted additions are not used in the quantitative metric calculations and are not counted toward the calculation of proxy capacity

2. Scale Down of Offered Capacity

Portfolios that include [redacted] utilize a scaled down quantity of the full [redacted] offered by the bidder [redacted]

In order to analyze these proposals as bid the Evaluation Team used scaled down capacities from the [redacted] during the evaluation of specific Portfolios. These Portfolio cases include the full [redacted] offshore wind in the model with [redacted] being the scaled down contracted capacity and [redacted] MW of additional non-contracted capacity. As stated above, non-contracted additions of offshore wind affect only indirect customer benefits and are not used directly in the quantitative metric calculations and are not counted toward in the calculation of proxy capacity. The Evaluation Team specifically confirmed this aspect of these [redacted] with the bidder through specific questions and answers. This approach was also consistent with the treatment of the proposals of the other bidder in the RFP, [redacted]

3. Use of As-bid Alternative Point of Interconnection

To reflect the expected status of ISO-NE's interconnection process as accurately as possible, Proposals and Portfolios that include the [redacted] are analyzed with a part of the proposed offshore wind capacity interconnected at the [redacted] substation as an alternative point of interconnection, as was offered / proposed by the bidder.

[redacted]

Based on the outcome of ISO-NE's first Cape Cod interconnection study, the Evaluation Team concluded that there was likely to be insufficient capacity at the bidder's queue position to accommodate the full 83C III bid [redacted] On this basis, the Evaluation Team determined that it was most accurate to use the alternate POI at [redacted] Impacted Proposal and Portfolio models include these modifications to the offshore wind POIs and their associated transmission changes.

[redacted]

- [redacted]

REDACTED

- [redacted]

[redacted]

C. PROCESS MODIFICATIONS BASED ON CHANGED CIRCUMSTANCES AND SPECIFIC BID CHARACTERISTICS

1. Use of Adjusted Quantitative Scores

[redacted]

4 The Evaluation team assessed various alternatives to evaluate such proposals including running an alternate Base Case, running affected Proposal and Portfolio Cases without the contract adjustment, and running non-affected Proposal and portfolio cases with the contract adjustment.

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[redacted]

2. Use of Alternative Qualitative Score

Some Proposals and Portfolios that include the [redacted] use alternative qualitative scores that account for the interconnection of some capacity to the [redacted] substation. For additional details, refer to the footnote in the result ranking sheets.

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APPENDIX E:
83C III Base Case Results

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83C III BASE CASE CAPACITY EXPANSION MODEL RESULTS REVIEW

Massachusetts 83C III OSW Evaluation

December 1, 2021

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Table of Contents

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Introduction

The 83C III Base Case is a reference point or benchmark against which we measure the incremental impacts of each 83C III Proposal. It is a “counterfactual” projection of market parameters for a scenario key electricity market parameters including electricity prices, REC prices, carbon emissions and in which the Commonwealth does not acquire the 1,600 MW of offshore wind through this RFP. EDCs used this approach to develop a Base Case for evaluation of 83D, 83C I and 83C II proposals.

It is not a plan for the Massachusetts electric sector and should not be viewed as such.

The Base Case model is developed through a combination of a long-term capacity expansion model (CapEx) and an hourly SCUC/SCED Energy & Ancillary Services (E&AS) model covering the ISO-NE and neighboring NYISO footprints over the evaluation period from 2025 through 2050.

It assumes:

- Implementation of all resources selected in recent clean energy procurements in New England states and New York. It also includes anticipated near term additions that have cleared capacity auctions and/or other ISO published documentation.
- Compliance with all legislative requirements and regulations in effect as of June 15, 2021 including class 1 Renewable Portfolio Standard (RPS) regulations in all New England states and NYISO including the cap on carbon emissions from electric generating units located in MA, the MA Clean Energy Standard (CES), New York CLCPA targets of 70% RPS by 2030 and a net zero carbon target by 2040.
- Compliance with MA Class 1 RPS and CES requirements, installed capacity requirements for reliability, as well as compliance with emission caps through incremental model selected retirements and additions of generic thermal and renewable capacity selected by the ENELYTIX capacity expansion model.

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Overview of Base Case Modeling Process

INPUT ASSUMPTION CATEGORIES

- Load forecasts
- Transmission Topology
- Capacity Requirements
- RPS Requirements
- Generation Mix
- Replacement Capacity
- Capital & Operating Costs
- Fuel and Emission Prices

ENELYTIX MODELS

- Capacity Expansion
- Energy & Ancillary Services

MODEL OUTPUTS

- Unit retirements; generic capacity additions;
- REC, CEC prices, Emission Cap compliance prices
- Generation by source, carbon emissions, gas burn, nodal LMPs

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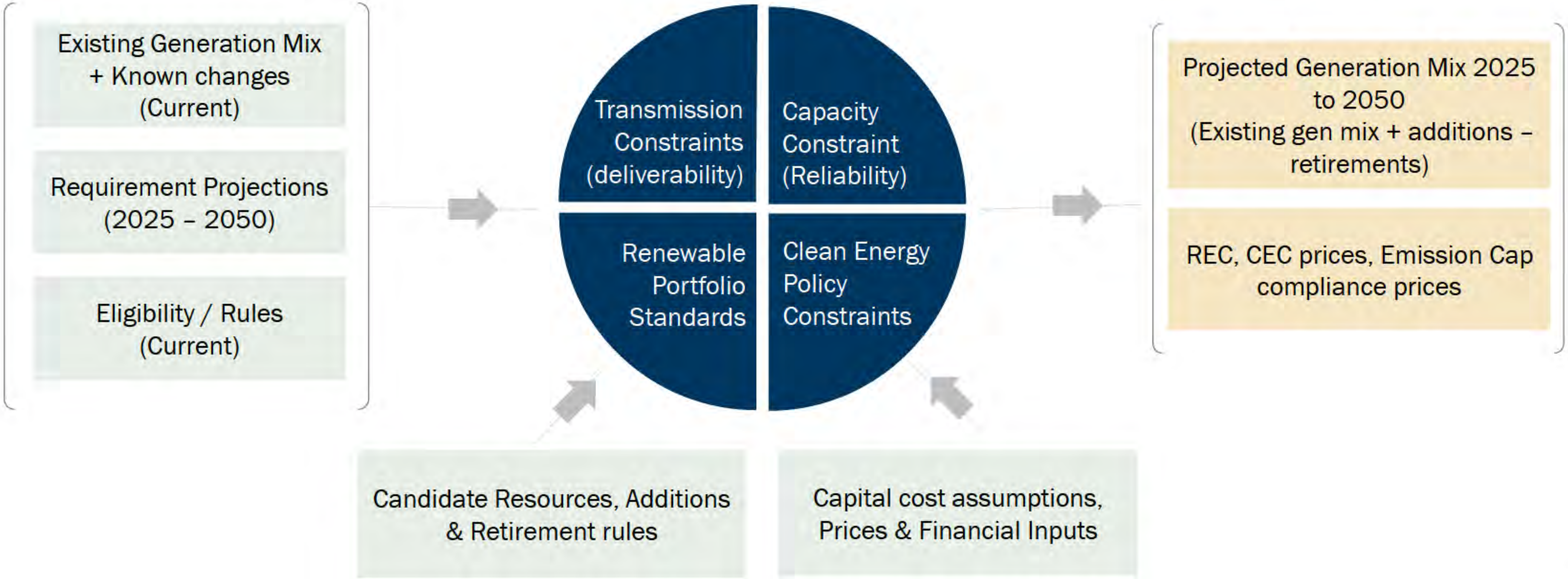
The Capacity Expansion Model

- Capacity Expansion module determines the optimal capacity expansion plan over the study period and resulting changes to the capacity and generation mix over that period.
- Its objective function is to minimize the net present value of the total cost, i.e., capital, fuel and operating, of the generation fleet serving the forecast load in the wholesale market within the ISO-NE electrical footprint, subject to various constraints.



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Capacity Supply and Demand

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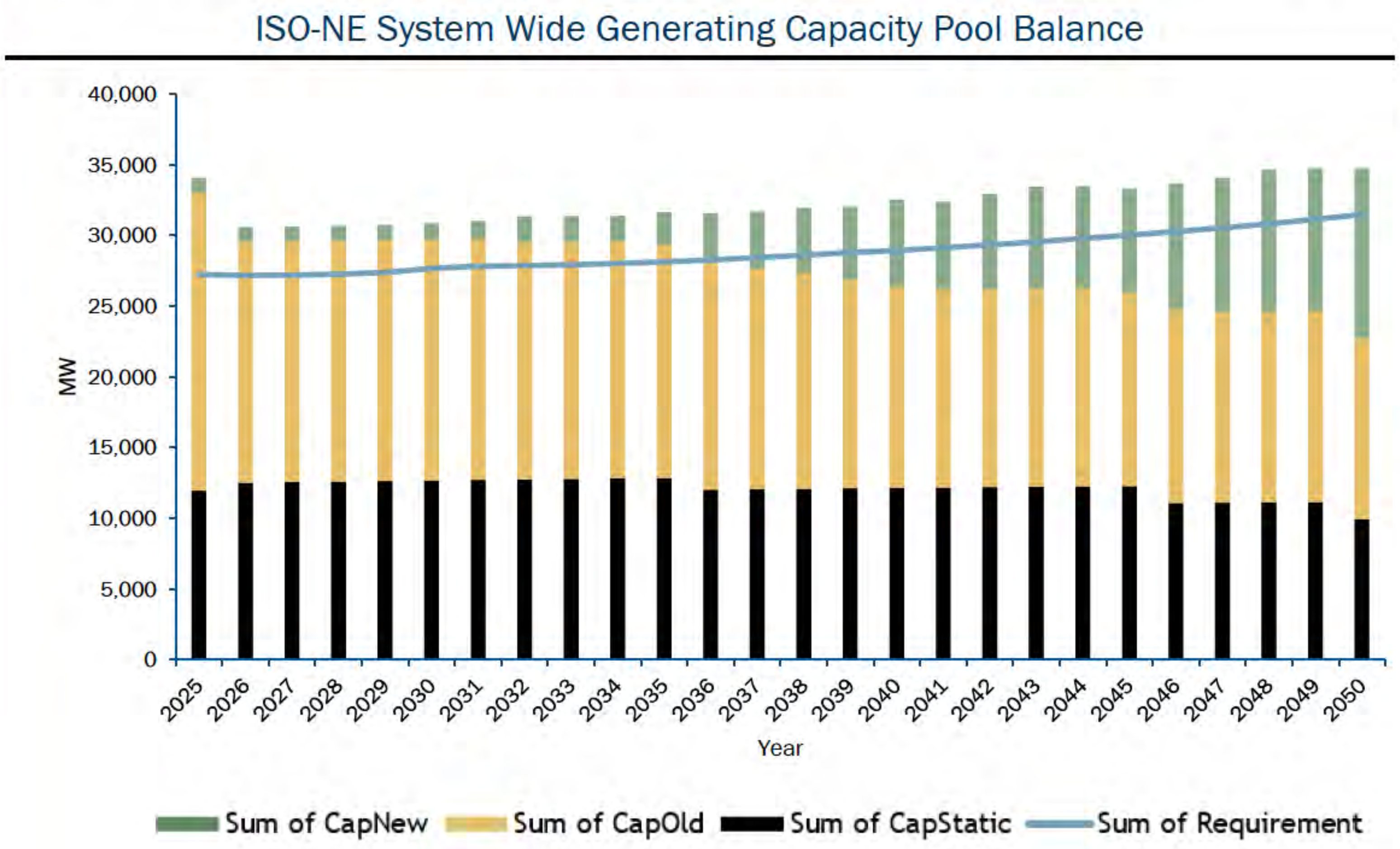
ISO-NE System Wide Generating Capacity Balance



- ISO-NE is a summer peaking system under load forecast developed from 2021 CELT forecast and 2012 load shape.
- ISO-NE has surplus capacity throughout the study period. However, local capacity requirements continue to drive capacity changes.

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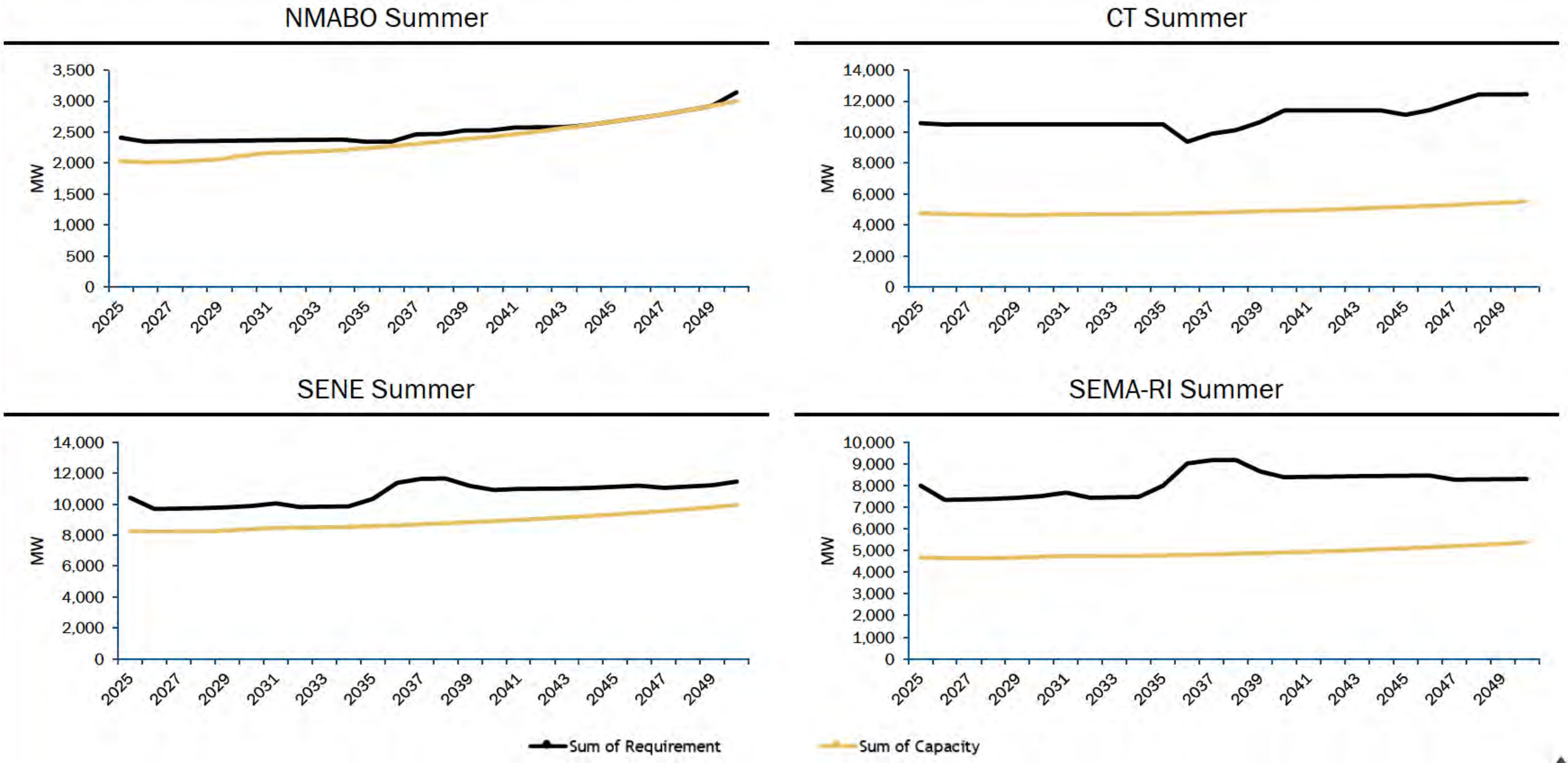
ISO-NE Capacity Balance by Zone- Import Constrained



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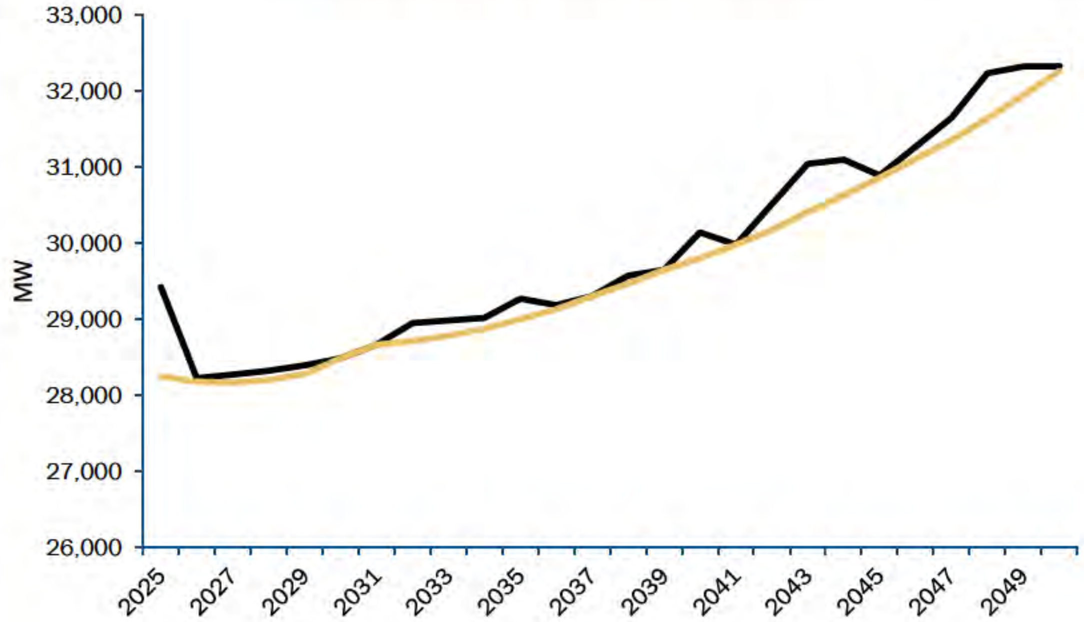
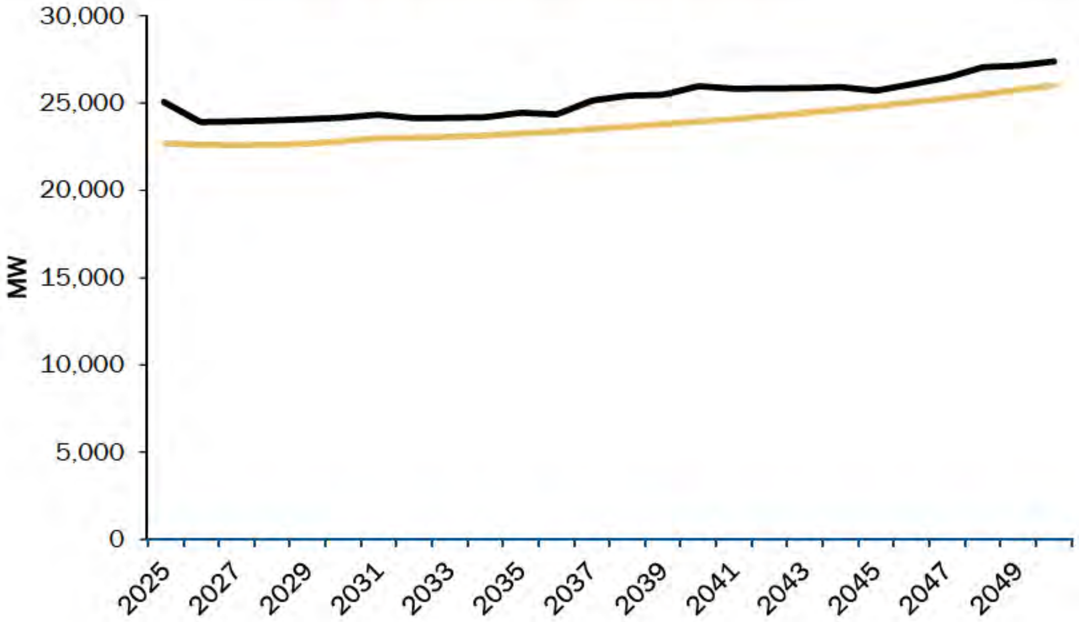
ISO-NE Capacity Balance by Zone- Export Constrained

Maine Rest-of-Pool Summer



NNE Rest-of-Pool Summer



Sum of Requirement   Sum of Capacity

NMABO and Maine ROP capacity zones drive capacity additions in ISO-NE. Remaining pools have varying levels of surplus against their requirements.

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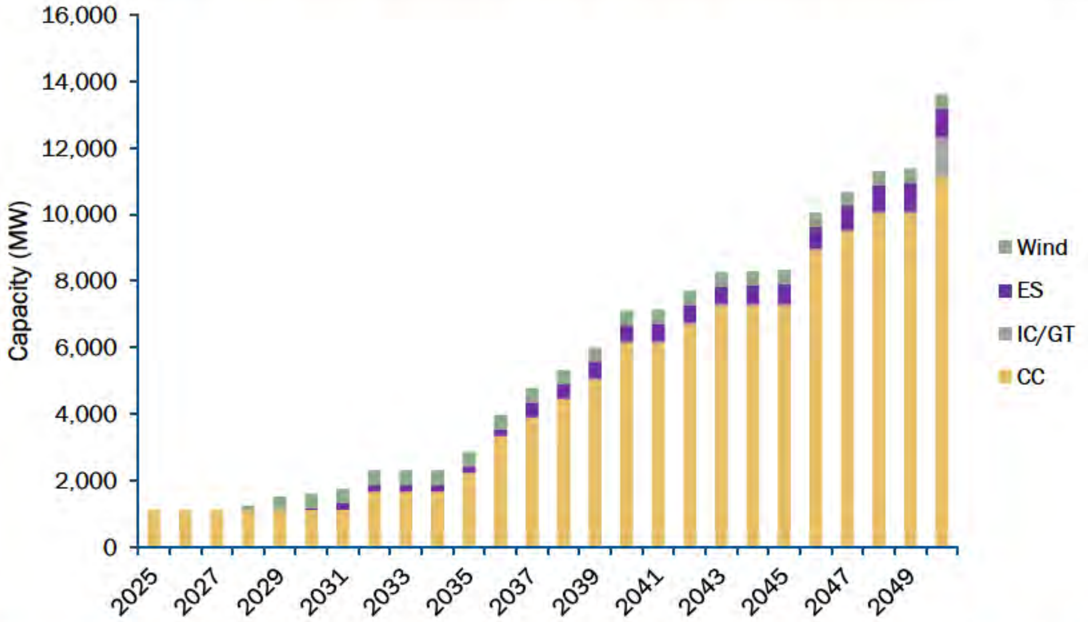
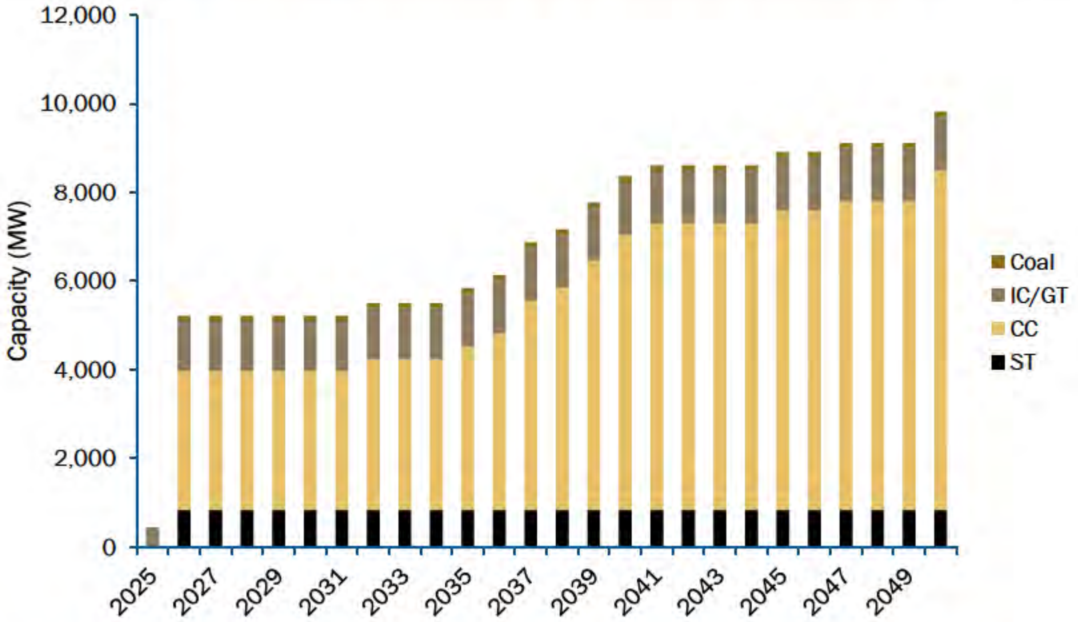
ISO-NE Capacity Changes by Type

ISO-NE New Additions by Type (Cumulative)



ISO-NE Retirement by Type (Cumulative)



- Model additions are predominantly thermal additions in the form of combined cycle units to replace retiring thermal capacity and scheduled nuclear retirements in 2034, 2045 and 2050.
- Model also adds some onshore wind however bulk of RPS compliance is met through the payment of ACPs (details to follow)
- Energy storage is added over the expansion period primarily to balance intermittent renewable generation.

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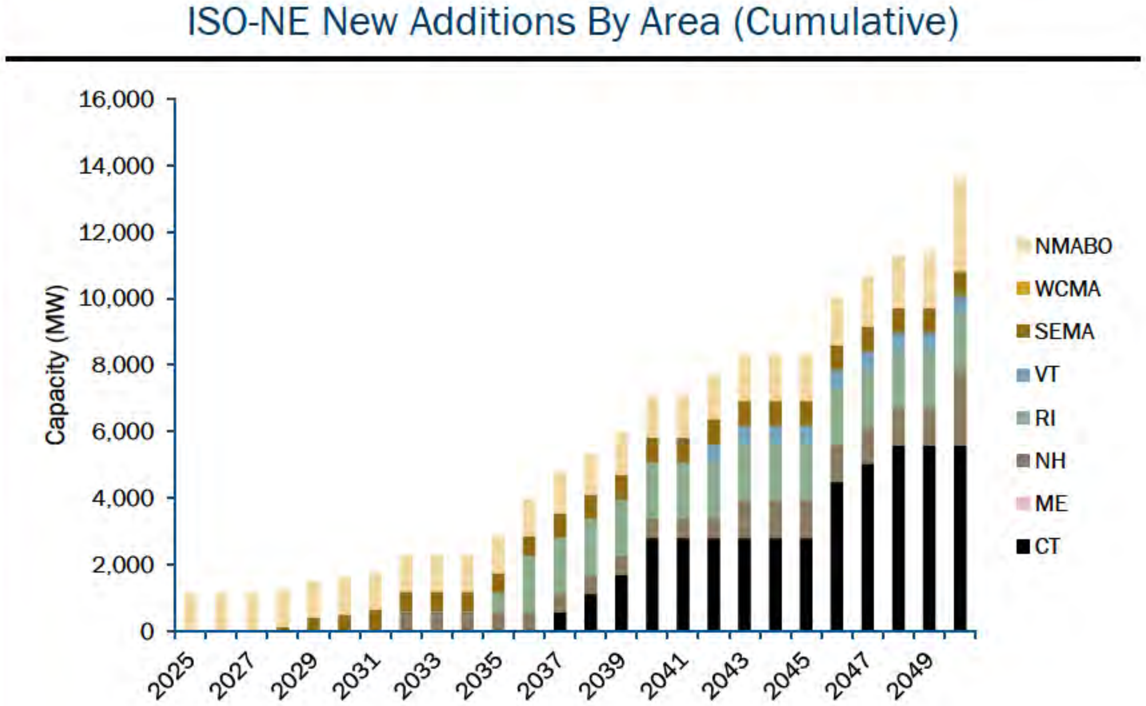
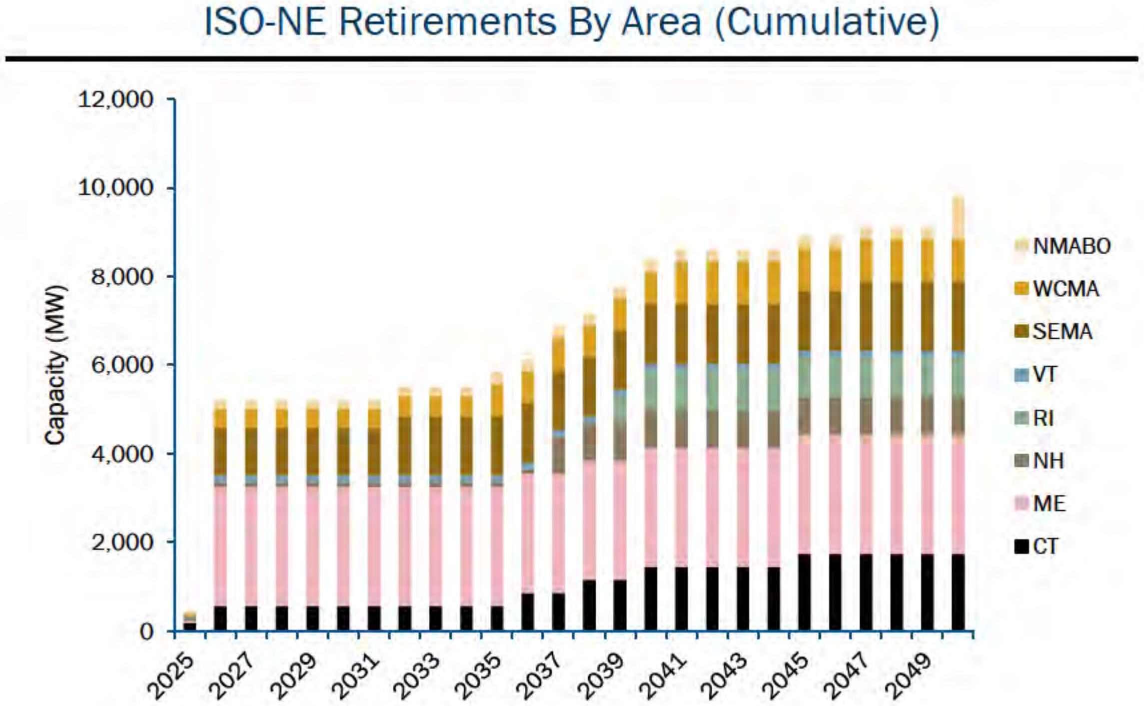
ISO-NE Capacity Changes by Area





- Additions begin in NEMA in order to fill the capacity gap
- Additions are added in neighboring states after 2035 when MA Carbon cap starts to bind
- Retirements are concentrated in ME, an export constraint area

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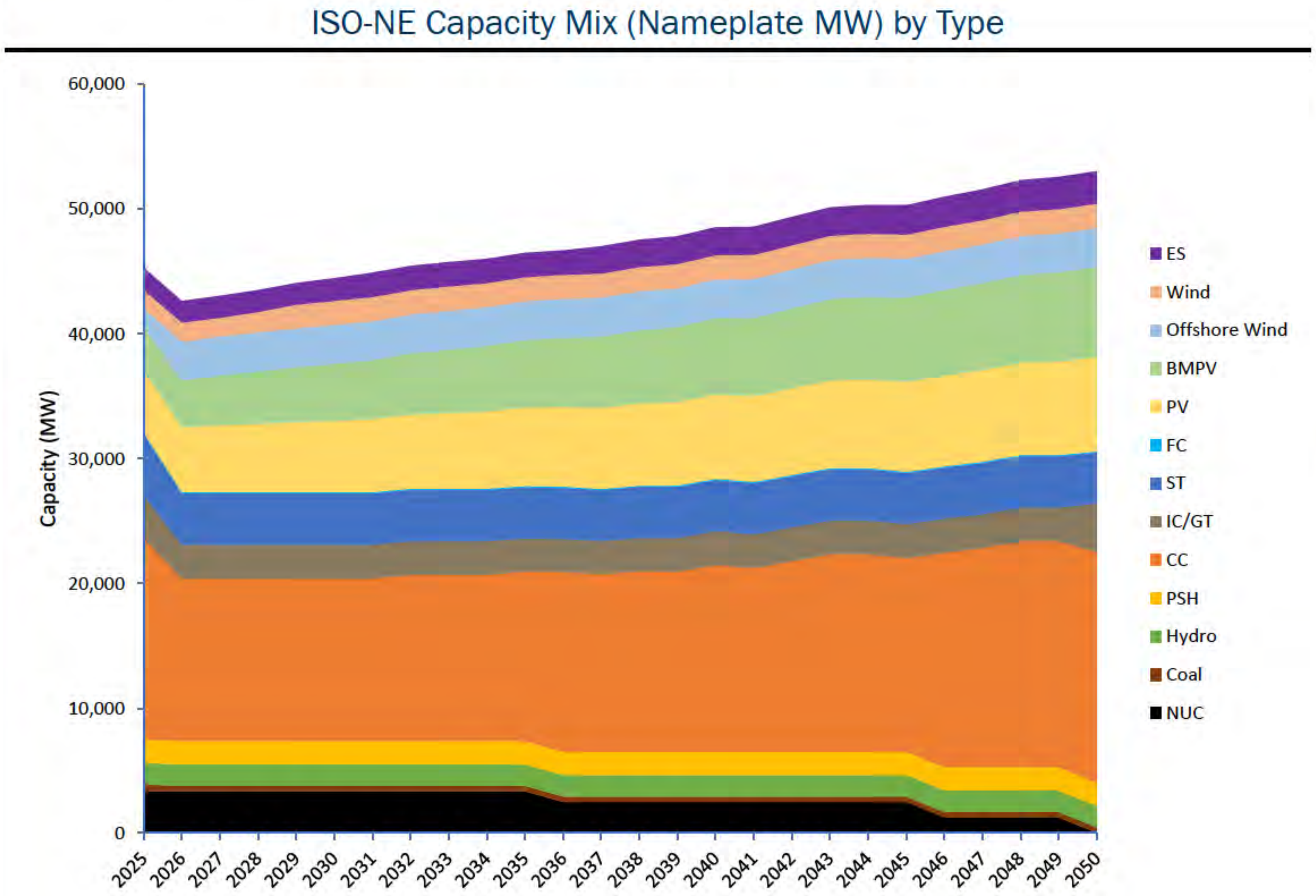
ISO-NE Capacity Mix



- The ISO-NE capacity mix remains dominated by gas fired generation with combined cycled being built to replace retiring nuclear units
- Model sees steady addition of forecasted PV and contracted offshore wind additions.

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ISO-NE Capacity Mix (Nameplate MW) by Type – Cont'd

Year	NUC	Coal	Hydro	PSH	CC	IC/GT	ST	FC	PV	BMPV	Offshore Wind	Wind	ES
2025	3,349	541	1,717	1,868	16,172	3,418	4,932	94	4,985	3,448	1,504	1,509	1,759
2026	3,349	439	1,717	1,868	13,033	2,705	4,108	94	5,209	3,749	3,112	1,509	1,759
2027	3,349	439	1,717	1,868	13,033	2,705	4,108	94	5,365	3,997	3,112	1,509	1,759
2028	3,349	439	1,717	1,868	13,033	2,705	4,108	94	5,482	4,206	3,112	1,633	1,759
2029	3,349	439	1,717	1,868	13,033	2,705	4,108	94	5,604	4,402	3,112	1,902	1,759
2030	3,349	439	1,717	1,868	13,033	2,705	4,108	94	5,717	4,575	3,112	1,937	1,818
2031	3,349	439	1,717	1,868	13,033	2,705	4,108	94	5,836	4,751	3,112	1,937	1,957
2032	3,349	439	1,717	1,868	13,311	2,705	4,108	94	5,940	4,911	3,112	1,937	1,957
2033	3,349	439	1,717	1,868	13,311	2,705	4,108	94	6,064	5,092	3,112	1,937	1,957
2034	3,349	439	1,717	1,868	13,311	2,705	4,108	94	6,174	5,256	3,112	1,937	1,957
2035	3,349	439	1,717	1,868	13,589	2,644	4,108	94	6,281	5,415	3,112	1,937	1,957
2036	2,485	439	1,717	1,868	14,408	2,644	4,108	94	6,372	5,554	3,112	1,937	1,957
2037	2,485	439	1,717	1,868	14,225	2,644	4,108	94	6,486	5,719	3,112	1,937	2,203
2038	2,485	439	1,717	1,868	14,487	2,644	4,108	94	6,584	5,865	3,112	1,937	2,203
2039	2,485	439	1,717	1,868	14,436	2,713	4,108	94	6,679	6,005	3,112	1,937	2,238
2040	2,485	439	1,717	1,868	14,961	2,713	4,108	94	6,758	6,125	3,112	1,937	2,238
2041	2,485	439	1,717	1,868	14,715	2,713	4,108	94	6,861	6,274	3,112	1,937	2,280
2042	2,485	439	1,717	1,868	15,272	2,713	4,108	94	6,948	6,401	3,112	1,937	2,280
2043	2,485	439	1,717	1,868	15,829	2,713	4,108	94	7,031	6,524	3,112	1,937	2,280
2044	2,485	439	1,717	1,868	15,829	2,713	4,108	94	7,098	6,624	3,112	1,937	2,315
2045	2,485	439	1,717	1,868	15,534	2,713	4,108	94	7,190	6,756	3,112	1,937	2,365
2046	1,251	439	1,717	1,868	17,205	2,713	4,108	94	7,265	6,866	3,112	1,937	2,419
2047	1,251	439	1,717	1,868	17,555	2,713	4,108	94	7,337	6,970	3,112	1,937	2,475
2048	1,251	439	1,717	1,868	18,112	2,713	4,108	94	7,391	7,052	3,112	1,937	2,541
2049	1,251	439	1,717	1,868	18,112	2,713	4,108	94	7,473	7,167	3,112	1,937	2,610
2050	0	439	1,717	1,868	18,521	3,841	4,108	94	7,536	7,258	3,112	1,937	2,610

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Clean Energy Policy Compliance:

RPS & MA CES

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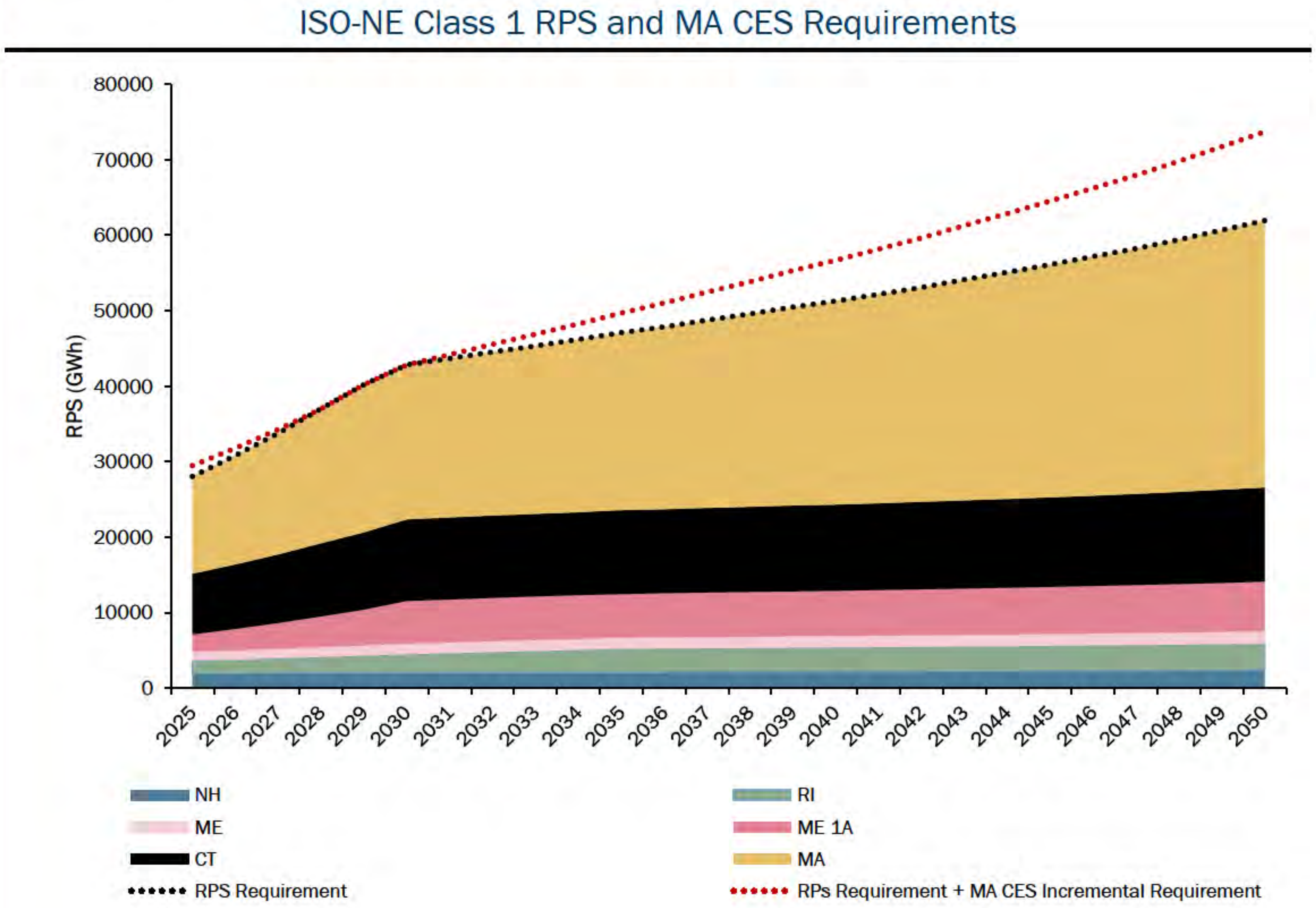
ISO-NE Class 1 RPS & CES - 1



- Introduction of new ME 1A requirements increases ME from 10% flat to 50% by 2030
- Increase in MA RPS requirements to 60% by 2050. Changes to regulation result in incremental MA CES requirements reducing to zero through 2029 but increasing thereafter.

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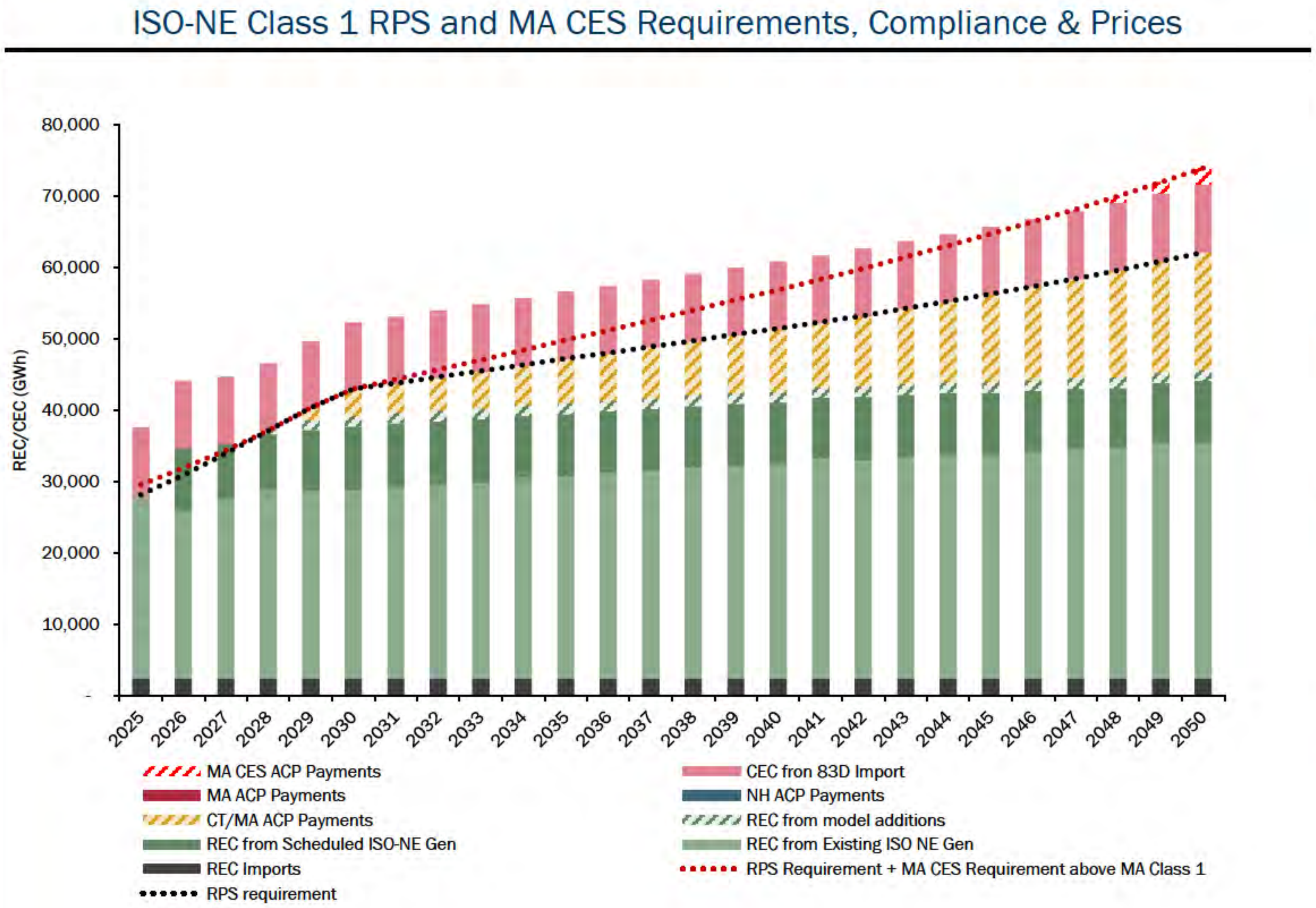
ISO-NE Class 1 RPS & CES Supply by Source



- MA CES remains in oversupply through 2046 beyond which compliance is met through CES ACPs
- Scheduled additions lead to REC oversupply over a short period in the near term.
- Compliance 2028 and beyond is met through the payment of identically priced CT and MA ACPs
- Model built renewables offset the RPS gap but not significantly.

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ISO-NE Class 1 RPS & CES Prices and ACP Cost

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ISO-NE Class 1 RPS & CES Summary

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Clean Energy Policy Compliance: Emission Reduction Targets

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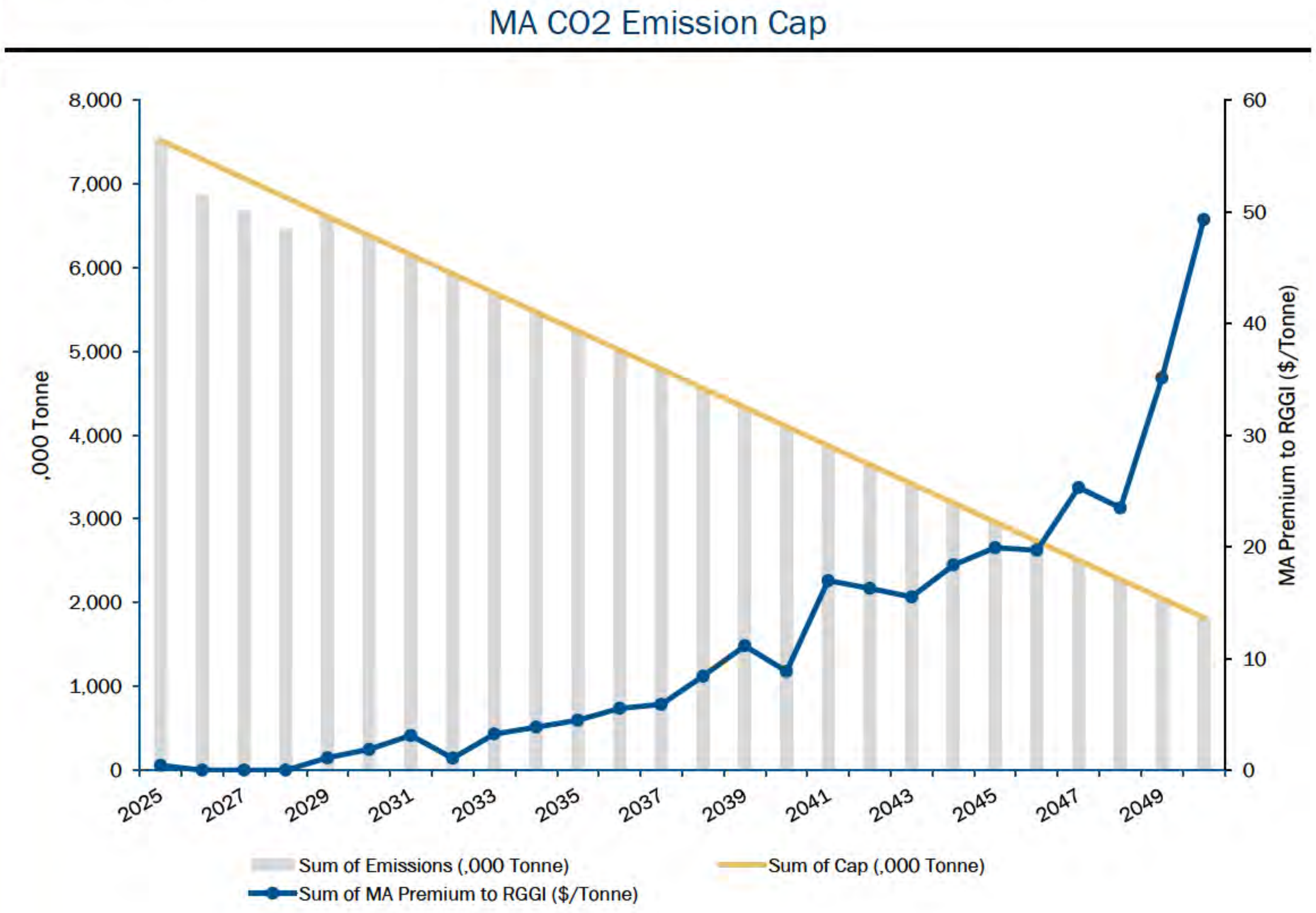
Massachusetts Carbon Cap



- MA carbon emission constraint binds throughout the study period.
- Cost of compliance increases as the cap reduces. Spikes in cost are seen when additional gas is built to replace retiring nuclear units.

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Energy & Ancillary Services Model Results

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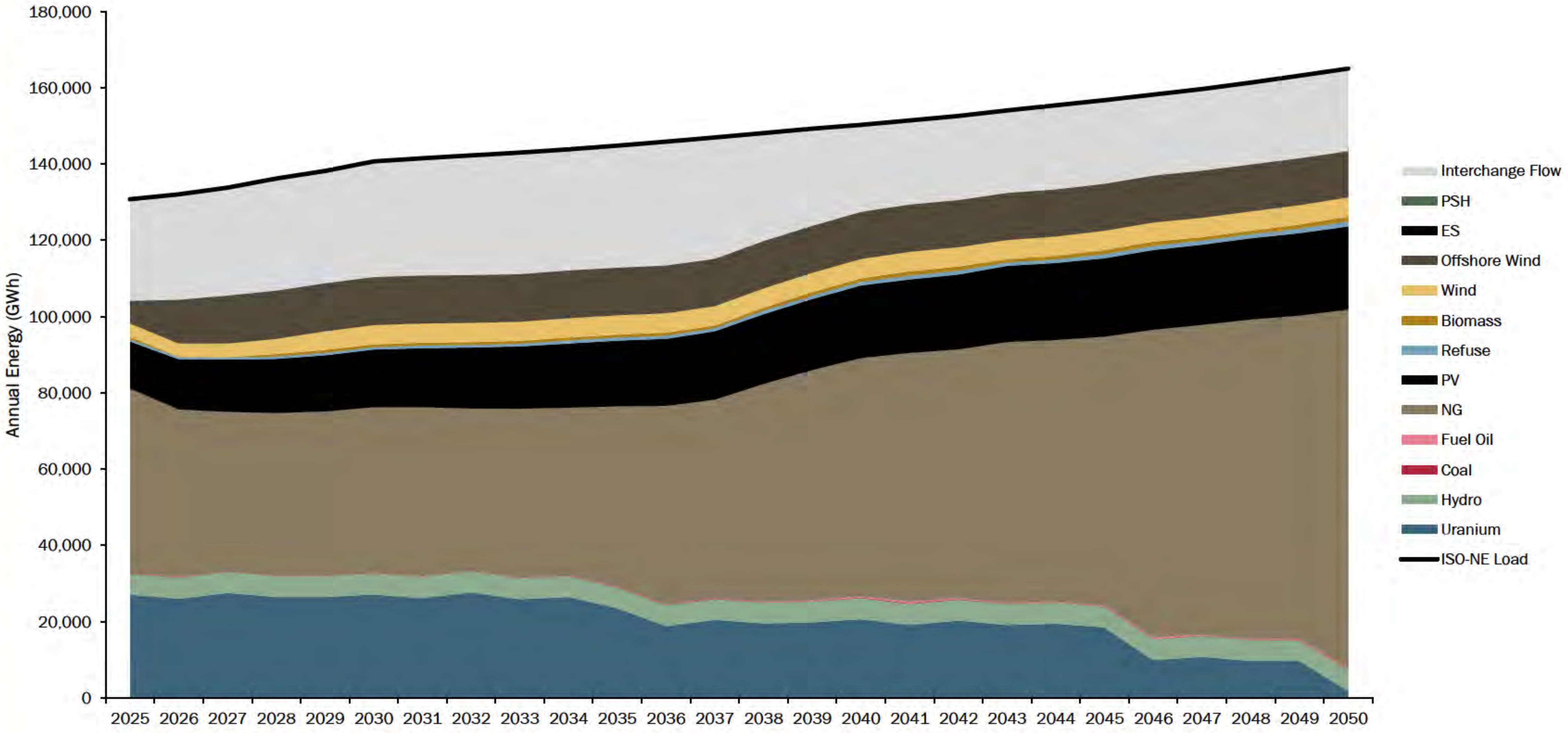
ISO-NE Annual Generation Mix by Fuel Type



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ISO-NE LMPs by Area

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APPENDIX F:
83C III Base Case Assumptions and Description of ENELYTIX simulation model

F.1: New England Document

Draft Report

Base Case for valuation of 83C Part III Proposals -

Input and Modeling Assumptions

New England

Prepared for: **Eversource Energy, National Grid. Unitil**

Tabors Caramanis Rudkevich

March 15th, 2022

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DISCLAIMER

Tabors Caramanis Rudkevich, INC (TCR) has been contracted by the Massachusetts Electric Distribution Companies (EDCs), Eversource, National Grid and Unitil to provide the quantitative analyses that will allow the EDCs to evaluate the proposals that they receive in response to the 83C III RFPs. The information provided herein is solely for the purpose of development of a Base Case against which the proposed projects may be compared. Any other use of the materials without the explicit permission of TCR is strictly prohibited.

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CHAPTER 1: Base Case for Evaluation of 83C III Proposals – New England Assumptions

This document describes the modeling and input assumptions that the TCR team proposes for the New England power system model against which the Massachusetts electric distribution companies (EDCs) will measure the incremental costs and benefits of each Proposal received in response to the 83C III RFP. In this document, TCR refers to that model as the "83C III Base Case" or "Base Case".

The complementary document "Base Case Evaluation of 83C III Proposals – Input and Modeling Assumptions New York" describes all 83C III Base Case modeling and input assumptions that are specific to New York. This report describes the input and modeling assumptions that are common to both markets.

1.1: Background

The following legislation, plans and draft regulations provide the background to the development of a Base Case for evaluation of 83C III proposals.

- The Global Warming Solutions Act of 2008 (GWSA) requires Massachusetts to reduce the greenhouse gas (GHG) emissions in its GHG inventory to "a 2050 statewide emissions limit that is at least 80 percent below the 1990 level." (Chapter 169 of the Acts of 2008)
- In 2010, to start the Commonwealth on a path towards meeting that target, the Secretary of the Massachusetts Executive Office of Energy and Environmental Affairs (EEA) set a statewide GHG emissions reduction limit of 25% for 2020 and released a plan to meet that 2020 target.
- In December 2015, the EEA released an update to that plan for 2020, the 2015 Update Massachusetts Clean Energy and Climate Plan for 2020 ("CECP Update"). The CECP Update includes discussion of policies that would deliver additional GHG reductions over the 2020–2030 time frame and beyond. For the electric sector, the policies for 2020 and beyond included clean energy imports and a clean energy standard (CES).
- In August 2016, the State legislature passed An Act to Promote Energy Diversity requiring the Massachusetts EDCs to undertake two procurements for supplies of clean energy to help Massachusetts achieve its GWSA targets. Under Section 83D, the EDCs issued an RFP for long term contracts for incremental clean energy generation and associated environmental attributes and/or renewable energy certificates ("RECs"), for approximately 9,450,000 MWh to be procured pursuant to cost-effective long-term contracts by 2022. Section 83C, requires the EDCs to procure long term contracts for RECs for energy or for a combination of both RECs and energy from offshore wind energy generation equal to approximately 1,600 megawatts of aggregate nameplate capacity not later than June 30, 2027. (Chapter 188 of the Acts of 2008)

- On August 11, 2017, Massachusetts promulgated new regulations and amendments designed to limit and reduce GHG emissions in Massachusetts. The regulations for the electric sector, 310 CMR 7.74 and 310 CMR 7.75, are a cap on carbon emissions from electric generating units (EGU) located in MA, and a Clean Energy Standard (CES). A Massachusetts Department of Environmental Protection (DEP) background document anticipates that the clean energy supplies Massachusetts EDCs contract through the 83C and 83D RFP process will "…deliver adequate quantities of clean energy that count toward CES compliance…"[1]
- On July 23, 2018, the electric distribution companies filed long-term contracts with Central Maine Power Company and H.Q. Energy Services (U.S.) Inc. for the New England Clean Energy Connect 100% Hydro project ("NECEC Hydro") for review and approval by the Department of Public Utilities. The NECEC Hydro project was selected pursuant to the Section 83D Procurement. (DPU 18-64, 18-65, 18-66)
- On July 31, 2018, the electric distribution companies filed long-term contracts with Vineyard Wind LLC for an 800 megawatt offshore wind generation project ("800 MW Vineyard Wind Project") for review and approval by the Department of Public Utilities. The Vineyard Wind project was selected pursuant to the Section 83C Procurement. (DPU 18-76, 18-77, 18-78)
- In August 2018, the State legislature passed An Act to Advance Clean Energy which directed the department of energy resources to investigate the necessity, benefits, and costs of requiring distribution companies to jointly and competitively conduct additional offshore wind generation solicitations and procurements of up to approximately 1,600 megawatts of aggregate nameplate capacity, in addition to the solicitations and procurements required by section 83C of chapter 169 of the acts of 2008, as amended by chapter 188 of the acts of 2016, and may require said additional solicitations and procurements by December 31, 2035. (Chapter 227 of the Acts of 2018)
- On May 23, 2019 the Massachusetts Electric Distribution companies, in coordination with the Massachusetts Department of Energy Resources, issued an RFP for Long-term Contracts for Offshore Wind Energy Projects pursuant to Section 83C of Chapter 169 of the Acts of 2008, as amended by chapter 188 of the Acts of 2016, An Act to Promote Energy Diversity.
- In August 2019, the State legislature passed An Act Relative to Offshore Wind Contract Pricing making modifications to chapter 169 of the Acts of 2008.
- On February 11, 2020, the electric distribution companies filed long-term contracts with Mayflower Wind Energy LLC for an 804 megawatt offshore wind generation project ("804 MW Low Cost Energy") for review and approval by the Department of Public Utilities. The Mayflower Wind project was selected pursuant to the Section 83C Round II Procurement. (DPU 20-16, 20-17, 20-18)
- On March 26, 2021, Gov. Baker signed into law An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy which became effective June 24, 2021 which increases the

1 Background Document on Proposed New and Amended Regulations, DEP, December 16, 2016. Page 33

1,600 MW procurement target per Section 83C of Chapter 169 of the Acts of 2008 with 4000 MW. (Section 91 of Chapter 8 of the Acts of 2021)

- On May 7, 2021 the Massachusetts Electric Distribution companies, in coordination with the Massachusetts Department of Energy Resources, issued an RFP for Long-term Contracts for Offshore Wind Energy Projects pursuant to Section 83C of Chapter 169 of the Acts of 2008, as amended by Chapter 188 of the Acts of 2016, An Act to Promote Energy Diversity and Section 21 of Chapter 227 of the Acts of 2018, An Act to Advance Clean Energy. This is Massachusetts' third offshore wind solicitation and is part of a procurement schedule developed by the Distribution Companies and DOER.
- Amendment #400 to H4000 -Offshore wind energy contracts "shall ensure that the distribution companies enter into cost-effective long-term contracts for offshore wind energy generation equal to approximately 5,600 megawatts of aggregate nameplate capacity not later than June 30, 2027, including capacity authorized pursuant to section 21 of chapter 227 of the acts of 2018"

1.2: 83C III Base Case Design

The 83C III Base Case is not a plan for the Massachusetts electric sector, and it should not be viewed as such. Instead, the 83C III Base Case is a projection of the carbon emission and energy cost implications of a scenario that assumes the additional resources available to meet the regulations promulgated in August 2017 are limited to 83D resources selected through the 2017/2018 83D procurement, 1,600 MW of 83C resources selected through Part I & II of this procurement, other expected policy-driven additions and market-driven RPS Class 1 eligible resources.

This 83C III Base Case provides the Evaluation Team a "but for" or "counterfactual" projection of carbon emissions and costs associated with MA electricity consumption under a future in which the EDCs do not acquire 1,600 MW of offshore wind for delivery by 2030 under long-term contracts with proposals received and selected in response to the 2021 83C III RFP. The 83C III Base Case serves as a common reference point or benchmark against which the EDCs measure the incremental costs and benefits of each Proposal received in response to the 83C III RFP.

The 83C III Base Case reflects all legislative requirements and regulations in effect as of June 15, 2021 including Renewable Portfolio Standard (RPS) regulations in MA and other New England states and the two regulations affecting the electric sector promulgated on August 11, 2017. These are regulation 310 CMR 7.74, a cap on carbon emissions from EGUs located in MA, and regulation 310 CMR 7.75, a CES. The 83C III Base Case covers the period 2025 through 2050 and expresses cost data in constant 2021$ as of January 1, 2021 unless otherwise noted.

CHAPTER 2: Modeling Environment

TCR employs ENELYTIX to model the Base Case and Proposal Cases. Appendix 1 describes the ENELYTIX platform in detail.

TCR uses ENELYTIX to develop an internally consistent, accurate set of Base Case prices in New England wholesale markets for energy and ancillary services, RECs, and Clean Energy Certifications (clean generation attributes, or "CECs") through the interaction of its two key modules: the Capacity Expansion module and the Energy and Ancillary Services (E&AS) module. Figure 1 illustrates this interaction.

- The Capacity Expansion module determines the long-term optimal electric system expansion in New England subject to relevant resource adequacy and environmental constraints. These include system-wide and zonal installed capacity requirements (ICR), RPS requirements and carbon emission limits on Massachusetts EGUs. This module models the power system footprint at the zonal level consistent with the design of the capacity markets in ISO-NE.
- The Energy and Ancillary Services (E&AS) module simulates the Day-Ahead and Real-Time market operations within the footprint of the ISO-NE and New York Independent System Operator (NYISO) power systems and markets. This model implements chronological simulations of the Security Constrained Unit Commitment (SCUC) and Economic Dispatch (SCED) processes, as well as the structure of the ancillary services in ISO-NE and NYISO markets. The E&AS model is fully nodal, performs true Mixed Integer Programming (MIP) based optimization, uses no heuristics, rigorously optimizes storage facilities, phase shifters and High Voltage Direct Current (HVDC) operation and accounts for marginal transmission losses.

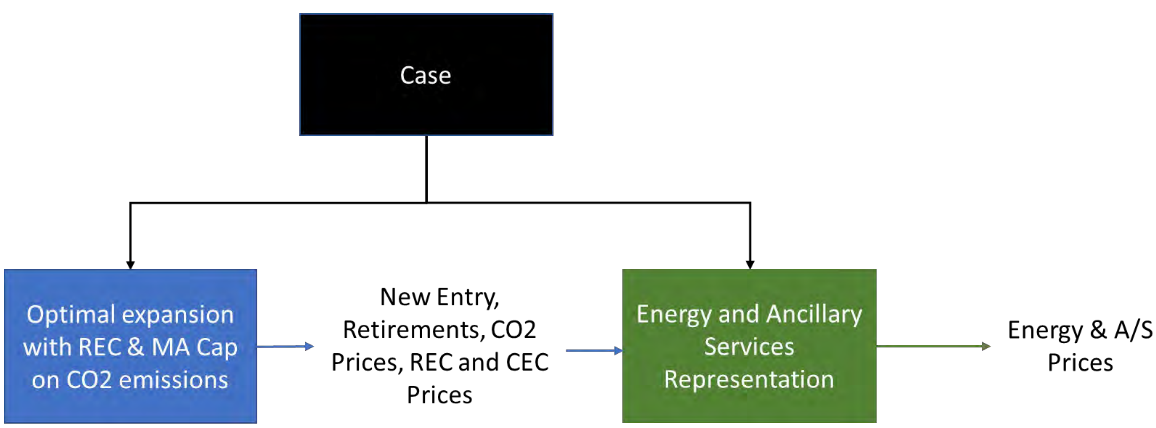

Figure 1. Interactive Use of ENELYTIX Modules

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The sequence of deploying these modules, as illustrated in Figure 1, is as follows:

- Development of the Base Case begins with application of the Capacity Expansion module, which determines the optimal capacity expansion plan and resulting changes to the generation mix over time, Class 1 REC prices, prices for the MA Clean Energy Credits (CEC) and the shadow price of CO_2 in Massachusetts implied by compliance with the hard cap on emissions from EGUs located in Massachusetts.
- Outputs from the Capacity Expansion module are inputs to the Energy and Ancillary Services module. These outputs include new entry and retirement decisions and shadow prices of CO_2 emissions along with the CO_2 shadow prices associated with the Regional Greenhouse Gas Initiative (RGGI) program. The E&AS module provides chronological unit commitment and dispatch modeling. This module among other things calculates locational marginal prices for load and generators and net revenues that each generating unit would receive from the Energy and A/S markets.

Both modules use the Power System Optimizer (PSO) solver developed by Polaris Systems Optimization, Inc.[2] which serves as a key component of the ENELYTIX modeling environment. Within ENELYTIX, both modules rely on the same dataset for ISO New England and share the economic and operational characteristics of ISO-NE's existing generating units, representation of the electric transmission system, and projection of future electricity demand.

All modules use the input assumptions in Chapter 3 through 14 where applicable as summarized by module in Table 1**Error! Reference source not found.** below.

Table 1. Applicability of Input and Assumption Categories by ENELYTIX Module

Chapter	Capacity Expansion Module	E&AS Module
3. Transmission	Interfaces only	All transmission constraints
4. Interchange	fixed schedule	economically scheduled
5. Load Forecast	Seasonal Load Duration Curves	Hourly chronological
6. Ancillary Services	N/A	Modeled in detail
7. Installed Capacity Requirements	By Zone	N/A
8. RPS Requirements	Yes	REC Prices from Capacity Expansion
9. MA Clean Energy Standards and Carbon Emissions Regulations	Yes	CO_2 shadow prices from Capacity Expansion

2 www.psopt.com

Chapter	Capacity Expansion Module	E&AS Module
10. Generating Units Retirements	Yes	from Capacity Expansion
11. Generating Units Capacity Additions	Yes	from Capacity Expansion
12. Generating Unit Operational Characteristics	Yes	Yes
13. Fuel Prices	Yes	Yes
14. Emission Rates and Allowance Prices	Yes	Yes

2.1: Capacity Expansion Module

The discussion that follows summarizes the methodology used by the Capacity Expansion Model to simulate EGU investment and retirement decisions and calculate market prices for energy, RECs and CECs and shadow prices for Massachusetts CO_2 emissions. The specific values of the input assumptions the Capacity Expansion Model uses to model the Base Case are provided in the remaining chapters of this document unless indicated otherwise.

The Capacity Expansion Module solves a dynamic multi-year optimization problem using a MIP optimization solver. The problem is solved over a 35- year optimization horizon (2025 – 2060) which consists of a 25-year evaluation period and a 10-year lookahead. The objective function is to minimize the net present value of the total cost, i.e., capital, fuel and operating, of the generation fleet serving the wholesale market within the ISO-NE electrical footprint.

These costs are minimized subject to the resource adequacy, operational and environmental constraints. By respecting these constraints, the optimization algorithm explicitly evaluates the needs for:

- energy delivered to each load zone to meet consumers' demand in that zone,
- installed capacity in each reliability zone to assure resource adequacy (reliability) of the system,
- curbing CO_2 emissions by generating plants in Massachusetts to comply with the final 310 CMR 7.74 rules,
- energy produced by new renewable resources procured to comply with state-specific Class 1 RPS and Massachusetts CES requirements, and
- retaining the power flow within the capacity of the transmission network.

While processing these requirements, the algorithm evaluates trade-offs between the capital and operating costs of existing and new resources vis-à-vis their ability to meet these requirements and standard operating constraints. Through finding the global minimum for the net present value of total costs, the algorithms identify the optimal resource mix, locational and technology specific new build decisions and retirement decisions. It also computes shadow prices for environmental constraints.

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The resource adequacy constraints are specified in terms of installed capacity requirements for the ISO-NE system as a whole and for reliability zones within ISO-NE as depicted in Figure 2. These requirements are met by maintaining sufficient generating capacity within each of these reliability zones.

ISO New England performs an annual resource adequacy assessment to develop locational requirements which are then used as inputs to develop parameters for the Forward Capacity Market. This assessment, however, is prepared only for the year for which it conducts the Forward Capacity Auction (FCA). The most recent FCA15 covered the 2024/25 capacity year. Using statistical data for past resource adequacy analyses performed by ISO-NE, forward projections of electricity demand and future limits on transmission interfaces defining reliability zones, TCR develops forward looking estimates of installed capacity requirements for all zones. Chapter 7 presents these estimates.

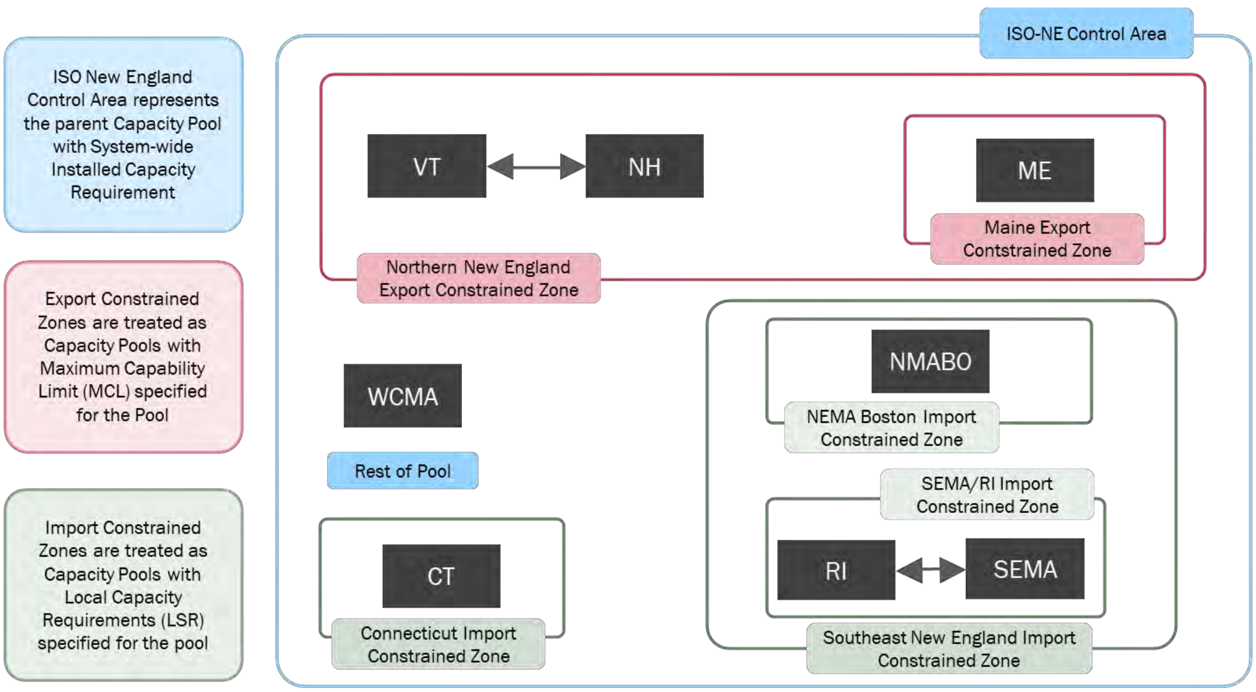

Figure 2. Representation of the Resource Adequacy Constraints in ISO-NE

The capacity expansion module provides a simplified representation of electric system operation compared to that of the E&AS module. Simplifications are necessary to reduce the size of the optimization problem and achieve computational tractability. The module uses three major simplifications.

1) It relies on load duration curves instead of chronological hourly modeling of electricity demand
2) It uses non-chronological dispatch of generation and does not model the unit commitment process

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3) It includes representation of transmission interfaces but does not model any other constraints or contingencies.

The model represents load duration curves for three seasons – Summer (June – September), Winter (December – March) and Shoulder (April, May, October and November). Load in each season is represented by blocks of various duration and magnitude that are assumed to remain constant within each block.

This load representation uniquely determines the season and block for each hour of the year. Using that relationship, the module develops average availability of variable resources such as wind and solar by block and season. Capacities of thermal and nuclear units are de-rated in the Shoulder season to account for planned maintenance. Additional derating accounting for forced outages is applied in all seasons.

To reflect the impact of operational constraints on the new build and retirement decisions, the module effectively simulates economic dispatch subject to transmission constraints represented by interfaces monitored by ISO-NE. In computing the impact of generation and loads on interface flows, the full representation of the transmission network which reflects both Kirchhoff's laws (the current law and the voltage law) is used.

The environmental constraints include requirements for state-by-state procurement of electric energy generated by renewable resources, as well as emissions requirements. The module represents each state's year-by-year Class 1 RPS requirements, Massachusetts CES requirements, state-specific resource eligibility, limitations on certificate banking and borrowing, and alternative compliance payment (ACP) prices that change over time. The module represents as a constraint the proposed CO_2 emission cap rules applicable to generators located in Massachusetts. The module uses projected RGGI CO_2 emission allowance prices as an input. Chapters 8, 9 and 14 discuss the detailed input assumptions and data sources.

The module determines Class 1 REC prices as the shadow price of the constraint associated with both meeting all states' RPS requirements through the addition of Class 1 eligible resources and meeting the Massachusetts incremental CES requirement through the addition of either Class 1 eligible resources or CES-eligible hydro resources. The module determines Massachusetts CEC prices as the Class 1 REC price minus the shadow price of the constraint associated with meeting all states' RPS requirements. The resulting REC and CEC prices in each year reflects the premiums that the marginal RPS and CES resources need above the energy and capacity market revenues they would receive, to recover their costs.

The capacity expansion module uses a two-phase approach: The *first phase* makes system expansion and retirement decisions subject to all resource adequacy, operational and environmental constraints <u>except for CES obligations</u>. The *second phase* dispatches the resources from phase 1 to comply with all obligations including CES, without allowing any additional capacity to be added or retired. This approach serves to create a true counter-factual system expansion case: first, it projects future generation mix in the absence of 83C CES obligations and then it values the impact of 83C III requirements imposed on such a system.

Shadow prices for Class 1 RPS and CES requirements obtained in the second phase are used as projection of Class REC and CEC prices, respectively.

The capacity of a given renewable resource type that can be built in a given year is subject to several constraints in the model:

- the estimated remaining technical potential for that resource type in each location
- the estimated maximum single-build capacity that of the resource type

Chapter 11 describes the characteristics of potential renewable resource capacity additions available to the capacity expansion module.

Our projections constrain Class 1 REC and Massachusetts CEC prices to be not less than $2/MWh (except in the presence of a higher administratively set floor price) nor more than $2/MWh below the ACP. The $2/MWh reflects the estimated transaction cost associated with buying and selling RECs and CECs in the market.

2.2: Energy and Ancillary Services Module

The ENELYTIX E&AS module is a detailed chronological production costing simulation model which implements SCUC and SCED based simulation of the electricity markets in ISO-NE and NYISO. This module embodies the most detailed operational representation of these electric markets and underlying power systems. In the balance of this document we provide the detailed inputs and assumptions underlying the models and algorithms as shown in Figure 3 below.

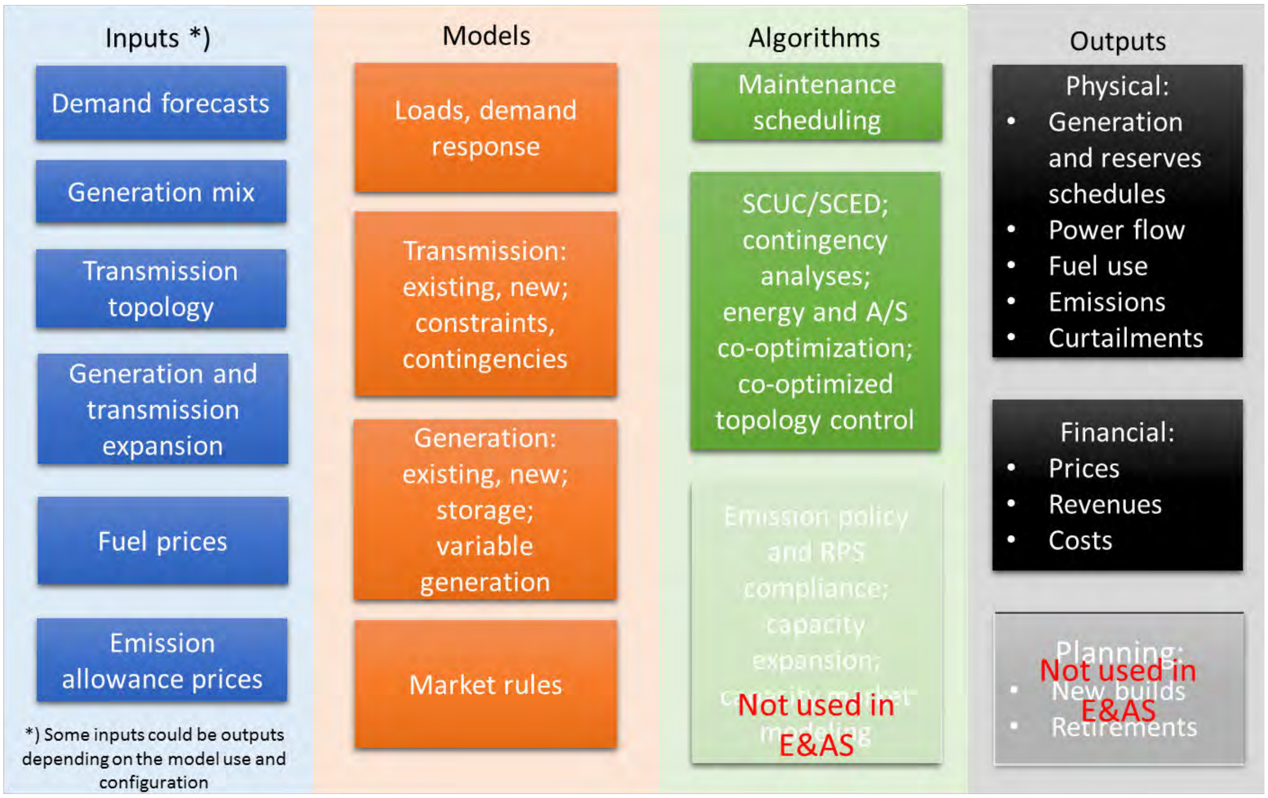

Figure 3. Schematic of the E&AS Module

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CHAPTER 3: Transmission

The geographic footprint modeled by in the Base Case encompasses the six New England states (Maine, Massachusetts, New Hampshire, Vermont, Rhode Island, and Connecticut) whose electricity movement and wholesale markets are coordinated by ISO-NE. In addition, the Base Case also incorporates a detailed representation of NYISO.

The ENELYTIX model organizes the physical location of all network resources and loads using bus bars and node mapping. Generators are mapped to bus bars/electrical nodes (eNodes). Bus bars are mapped to ISO-NE/NYISO zones and to specific areas outside the ISO-NE/NYISO system. The mapping of load nodes to ISO-NE/NYISO zones and areas outside ISO-NE/NYISO is used by ENELYTIX to allocate area load forecast to individual buses in proportion to bus specific loads in the power flow case.

The transmission topology and electric characteristics of transmission facilities for ISO-NE is modeled on the 2025 Summer Peak case obtained by EDCs from ISO-NE which is combined with the representation of the NYISO system obtained from the 2019 FERC 715 powerflow filings for summer peak 2024. TCR mapped New England generators and load areas to bus bars and electrical nodes (eNodes) associated with bus bars according to specifications provided by ISO-NE. Mapping of NYISO and generators and loads was provided by Newton Energy Group, ENELYTIX vendor. Contingencies and interface limit definitions were provided by the EDCs. Table 2 shows the major interfaces modeled in ISO-NE

Table 2. ISO-NE Modeled Interface Limits

Constraint Name	Summer Max (MW)	Summer Min (MW)	Winter Max (MW)	Winter Min (MW)
CSC	346	N/A	346	N/A
CT EXPORT	3,745	N/A	3,745	N/A
CT IMPORT	3,400	N/A	3,400	N/A
EAST-WEST	3,500	N/A	3,500	N/A
KEENE RD EXP	165	N/A	165	N/A
ME-NH	1,960	N/A	1,960	N/A
MEYNK_SOUTH	9,999	N/A	9,999	N/A
NE-BOSTON	5,700	N/A	5,700	N/A
NE-NWST	1,400	N/A	1,400	N/A
NE-NWVT	9,999	N/A	9,999	N/A
NE-SEMA/RI	1,280	N/A	1,280	N/A
NE-SWCT	9,999	N/A	9,999	N/A
NH-ME	2,200	N/A	2,200	N/A
NNE-SCOB+394	3,300	N/A	3,300	N/A
NORTH-SOUTH	2,840	N/A	2,840	N/A

Constraint Name	Summer Max (MW)	Summer Min (MW)	Winter Max (MW)	Winter Min (MW)
NVT-EXP	9,999	N/A	9,999	N/A
ORR_SOUTH	1,375	N/A	1,375	N/A
SBRK_SOUTH	1,700	N/A	1,700	N/A
SEMARI - NE	3,000	N/A	3,000	N/A
SNDYPD_EXP	2,000	N/A	2,000	N/A
SNDYPD_IMP	2,000	N/A	2,000	N/A
SNDYPD-SOUTH	4,300	N/A	4,300	N/A
SURW_SOUTH	1,600	N/A	1,600	N/A
W CT IMPORT	3,810	N/A	3,810	N/A
WEST-EAST	2,200	N/A	2,200	N/A
SEMA-NE	2,800	N/A	2,800	N/A
NE-NB	550	N/A	550	N/A
NE-NY	1,200	-1,200	1,200	-1,200
NNC	200	-200	200	-200
NB-NE	1,050	N/A	1,050	N/A

CHAPTER 4: Interchange

ENELYTIX models ISO-NE interchanges with neighboring regions as follows:

- NYISO interchanges: modeled as hourly economic dispatch
  - Cross Sound Cable HVDC interconnection with NYISO
  - Roseton AC interface with NYSIO
- Quebec interchanges: fixed hourly schedules, using interchange data from 2012 to align with hourly load and intermittent generation profiles. The 2012 data is similar to the 2020 data, so it was not updated.
  - Phases I and II Interface with Hydro Quebec via HVDC
  - Highgate interface with Hydro Quebec via HVDC
- New Brunswick interface at Keswig external node, hourly schedule from 2020. New Brunswick interchange is significantly different than it was in 2012, so data from 2020 was used.

In all instances TCR calendar shifts the interchange flow data for each forecast year to assure that the flow levels remain synchronized with the load pattern in ISO-NE.

Table 3 summarizes the fixed interchange flow schedules between ISONE and neighboring non-NYISO regions.

Table 3. Scheduled Net Interchange Summary

Interchange	Interface	Max Import (MW)	Max Export (MW)	Avg Import (MW)	Avg Export (MW)	Total Import (GWh)	Total Export (GWh)
NB	Keswig	981	391	294	11	2,585	94
HQ	HighGate	226	142	167	0	1,471	0.257
	P1&P2	1,853	0	1,321	0	11,607	0

CHAPTER 5: Load Forecast

This chapter describes the methodology TCR used to develop the load forecast used in this ISO-NE model. The load forecast consists of a single year hourly load shape and a monthly energy and peak forecast spanning the study period. ENELYTIX uses the monthly energy and peak forecast along with the single year hourly load shape to create an hourly demand schedule for the entire study period.

The monthly energy and peak forecast contains three components – gross load, energy efficiency (EE), and behind-the-meter photovoltaic generation (BTMPV). The single year annual load shape is the historical 2012 annual load.

5.1: Monthly Load Forecasts, 2025-2030

TCR developed the monthly energy and peak forecasts through 2030 using the 2021-2030 Forecast Report of Capacity, Energy, Loads, and Transmission (2021 CELT Report). TCR develops forecasts beyond 2030 by extrapolating the 2021 CELT Report forecasts throughout the rest of the study period.

The summer and winter peak load forecasts are coincidental “50/50” forecasts. Coincidental forecast reflects the zonal peak at the time ISO-NE system reaches peak demand instead of the true zonal peak. The 50/50 forecasts represent the median value of the distribution of demand based on different weather scenarios. The 2021 CELT Report also provides 90/10 summer and winter peak forecasts, which represent the 90th percentile forecast of load.

The 50/50 peak forecasts were used for the load forecast and for system-wide ICR requirements, while the 90/10 peak forecasts were used to calculate summer and winter LSR and MCL capacity requirements (see Chapter 7).

5.1.1: 2021 CELT Report Forecast for 2025 - 2030

The 2021 CELT Report provides forecasts of gross load, EE, and BTMPV through 2030.

Table 4 and Table 5 summarize the ISO-NE forecasts of annual energy and peak load by ISO-NE load zone for 2025 through 2030 from the 2021 CELT Report. These are forecasts of energy and peak requirements net of the impacts of reductions due to past, present, and future energy efficiency measures, referred to as EE. TCR uses these “Gross-EE” forecasts in the 83C III Base Case as energy and peak demand requirements. The 2021 CELT Report also includes projections of BTMPV and its impact on energy and peak load, which are drawn from the ISO-

NE Final 2021 PV Forecast created by the Distributed Generation Forecast Working Group.[3] BTMPV is not subtracted from these forecasts because BTMPV units are modeled in ENELYTIX as generators rather than load reduction for more accurate power flow analysis.

The forecasts are taken from tabs 2A, 2B, and 2C of the ISO New England CELT 2021 Forecast Data File. The annual energy and summer/winter peak forecasts were allocated into monthly forecasts using allocation factors based on historical hourly load data.

Table 4. Gross-EE Annual Energy Forecast by ISO-NE Area (GWh), 2025-2030

Zone	2025	2026	2027	2028	2029	2030
CT	30,262	30,353	30,503	30,758	30,894	31,129
ME	12,837	13,144	13,527	13,993	14,451	14,987
NH	12,845	12,989	13,163	13,389	13,552	13,756
*SEMA	16,185	16,340	16,565	16,875	17,127	17,452
*WCMA	16,931	17,097	17,336	17,666	17,932	18,276
*NMABO	27,672	27,971	28,389	28,956	29,421	30,013
MA	60,788	61,408	62,290	63,497	64,480	65,741
RI	8,217	8,280	8,392	8,544	8,682	8,852
VT	5,870	5,898	5,957	6,046	6,121	6,229
ISO-NE	*130,819*	*132,072*	*133,832*	*136,227*	*138,180*	*140,694*

Table 5. Gross-EE Coincident Summer Peak Load Forecast by ISO-NE Area (MW), 2025-2030

Zone	2025	2026	2027	2028	2029	2030
CT	6,543	6,523	6,509	6,503	6,505	6,529
ME	2,131	2,154	2,245	2,351	2,472	2,611
NH	2,382	2,385	2,392	2,401	2,413	2,431
*SEMA	3,230	3,213	3,202	3,199	3,201	3,221
*WCMA	3,272	3,257	3,249	3,248	3,253	3,275
*NMABO	5,435	5,418	5,413	5,418	5,434	5,480
MA	11,936	11,887	11,863	11,864	11,887	11,975
RI	1,880	1,888	1,900	1,915	1,931	1,952
VT	1,007	1,004	1,003	1,012	1,038	1,068
ISO-NE	*6,543*	*6,523*	*6,509*	*6,503*	*6,505*	*6,529*

* Note – Energy and peak loads for MA are aggregate of values for SEMA, WCMA and NMABO zones.

3 https://www.iso-ne.com/static-assets/documents/2021/03/final_2021_pv_forecast.pdf

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5.1.2: TCR Forecast of Annual Energy and Peak Load, 2031 - 2050

TCR develops energy and peak load forecasts for 2031 to 2050 by separately extrapolating Gross, “Gross-EE”, and BTMPV from the 2021-2030 forecasts available in the 2021 CELT Report.

Energy: TCR extended the 2021 CELT Report Gross energy forecast for ISONE using linear extrapolation based on all years of the forecast data (2021-2030). For the “Gross-EE” forecast, TCR extended the 2021 CELT Report Net Energy for Load forecast using annual growth rates for NEL from the 2021 EIA Annual Energy Outlook. BTMPV energy was extrapolated separately using methodology consistent with the ISO-NE 2021 Final PV Forecast, then added back into the NEL extrapolation to create a “Gross-EE” forecast for the entire study period. The “Gross-EE” forecast was distributed among the ISONE energy areas using allocation factors calculated based on the last year of the 2021 CELT Report forecast (2030).

Peak: TCR extended the 2021 CELT Report Gross peak forecast using linear extrapolation based on all years of the forecast data (2021-2030). For the summer and winter “Gross-EE” peak forecasts, TCR calculated the load factor based on the “Gross-EE” peak and energy forecast for each year in the 2021 CELT Report forecast, then logarithmically extrapolated the load factor to 2050. The “Gross-EE” forecast for 2031-2050 was created by multiplying the extrapolated load factor by the extrapolated “Gross-EE” energy forecast. The “Gross-EE” forecast was distributed among the ISONE energy areas using allocation factors calculated based on the last year of the 2021 CELT Report forecast (2030).

The annual energy and summer/winter peak forecasts were allocated into monthly forecasts using allocation factors based on historical hourly load data.

Table 6 and Table 7 show the “Gross-EE” energy and peak load projections by energy area and by year from 2031-2050.

Figure 4 and Figure 5 show “Gross-EE” energy and peak load projections by energy area and year for the entire study period 2025-2050.

Table 6. Gross-EE Annual Energy Forecast Summary by State (GWh)

Zone	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CT	31,321	31,493	31,667	31,854	32,079	32,295	32,565	32,808	33,069	33,289
ME	15,055	15,114	15,175	15,244	15,333	15,418	15,531	15,631	15,743	15,834
NH	13,833	13,902	13,973	14,051	14,147	14,241	14,359	14,467	14,584	14,683
*SEMA	17,576	17,679	17,782	17,892	18,023	18,149	18,304	18,444	18,594	18,721
*WCMA	18,681	18,804	18,927	19,057	19,208	19,352	19,527	19,685	19,852	19,995
*NMABO	29,877	30,005	30,137	30,284	30,469	30,647	30,880	31,087	31,314	31,501
MA	66,134	66,488	66,846	67,233	67,700	68,148	68,711	69,216	69,760	70,217
RI	8,907	8,956	9,007	9,062	9,129	9,195	9,276	9,350	9,430	9,499
VT	6,279	6,325	6,373	6,423	6,481	6,537	6,604	6,666	6,732	6,791
ISO-NE	*141,529*	*142,278*	*143,041*	*143,867*	*144,869*	*145,834*	*147,046*	*148,138*	*149,318*	*150,313*

Zone	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
CT	33,539	33,796	34,116	34,404	34,703	35,016	35,332	35,702	36,093	36,491
ME	15,942	16,054	16,199	16,329	16,465	16,609	16,757	16,931	17,117	17,308
NH	14,797	14,915	15,063	15,197	15,337	15,485	15,635	15,811	15,997	16,188
*SEMA	18,864	19,011	19,192	19,355	19,525	19,701	19,879	20,087	20,306	20,528
*WCMA	20,156	20,318	20,516	20,695	20,879	21,070	21,262	21,484	21,717	21,954
*NMABO	31,721	31,949	32,240	32,501	32,774	33,063	33,357	33,705	34,075	34,454
MA	70,741	71,278	71,948	72,551	73,178	73,834	74,498	75,276	76,098	76,936
RI	9,577	9,658	9,758	9,850	9,945	10,045	10,146	10,264	10,389	10,516
VT	6,856	6,923	7,002	7,075	7,151	7,229	7,309	7,399	7,494	7,590
ISO-NE	*151,452*	*152,624*	*154,086*	*155,406*	*156,779*	*158,218*	*159,677*	*161,383*	*163,188*	*165,029*

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Table 7. Gross-EE Annual Peak Forecast Summary by ISO-NE States (MW)

Zone	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CT	6,569	6,575	6,585	6,601	6,627	6,652	6,691	6,724	6,763	6,794
ME	2,623	2,628	2,640	2,655	2,672	2,689	2,711	2,730	2,750	2,768
NH	2,446	2,448	2,452	2,458	2,467	2,477	2,491	2,503	2,518	2,530
*SEMA	3,241	3,244	3,249	3,256	3,269	3,282	3,300	3,317	3,336	3,352
*WCMA	3,295	3,298	3,303	3,311	3,324	3,337	3,356	3,373	3,392	3,408
*NMABO	5,513	5,519	5,527	5,540	5,562	5,583	5,615	5,644	5,676	5,702
MA	12,048	12,060	12,078	12,106	12,154	12,201	12,271	12,334	12,404	12,462
RI	1,965	1,967	1,970	1,974	1,982	1,989	2,000	2,010	2,023	2,032
VT	1,070	1,075	1,080	1,086	1,092	1,099	1,109	1,116	1,125	1,132
ISO-NE	*6,569*	*6,575*	*6,585*	*6,601*	*6,627*	*6,652*	*6,691*	*6,724*	*6,763*	*6,794*

Zone	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
CT	6,833	6,873	6,927	6,975	7,026	7,080	7,136	7,202	7,273	7,346
ME	2,788	2,809	2,836	2,859	2,884	2,909	2,936	2,966	2,999	3,033
NH	2,544	2,559	2,579	2,597	2,616	2,636	2,656	2,682	2,708	2,735
*SEMA	3,371	3,390	3,417	3,441	3,466	3,493	3,520	3,553	3,588	3,624
*WCMA	3,427	3,447	3,474	3,498	3,524	3,551	3,579	3,612	3,648	3,685
*NMABO	5,734	5,768	5,814	5,854	5,897	5,942	5,989	6,044	6,104	6,165
MA	12,532	12,605	12,705	12,793	12,887	12,986	13,088	13,209	13,340	13,474
RI	2,043	2,055	2,071	2,086	2,101	2,117	2,134	2,154	2,175	2,197
VT	1,140	1,148	1,160	1,169	1,179	1,190	1,201	1,213	1,226	1,240
ISO-NE	*6,833*	*6,873*	*6,927*	*6,975*	*7,026*	*7,080*	*7,136*	*7,202*	*7,273*	*7,346*

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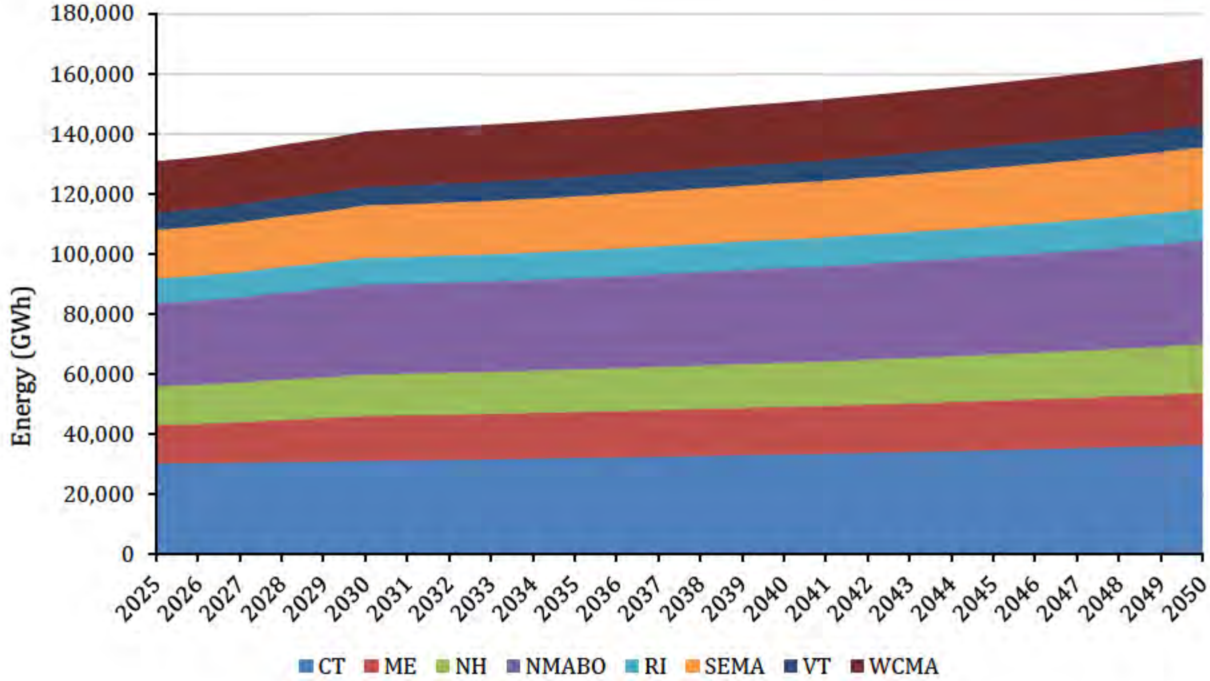

Figure 4. TCR Forecast Gross-EE Annual Energy by State (GWh)

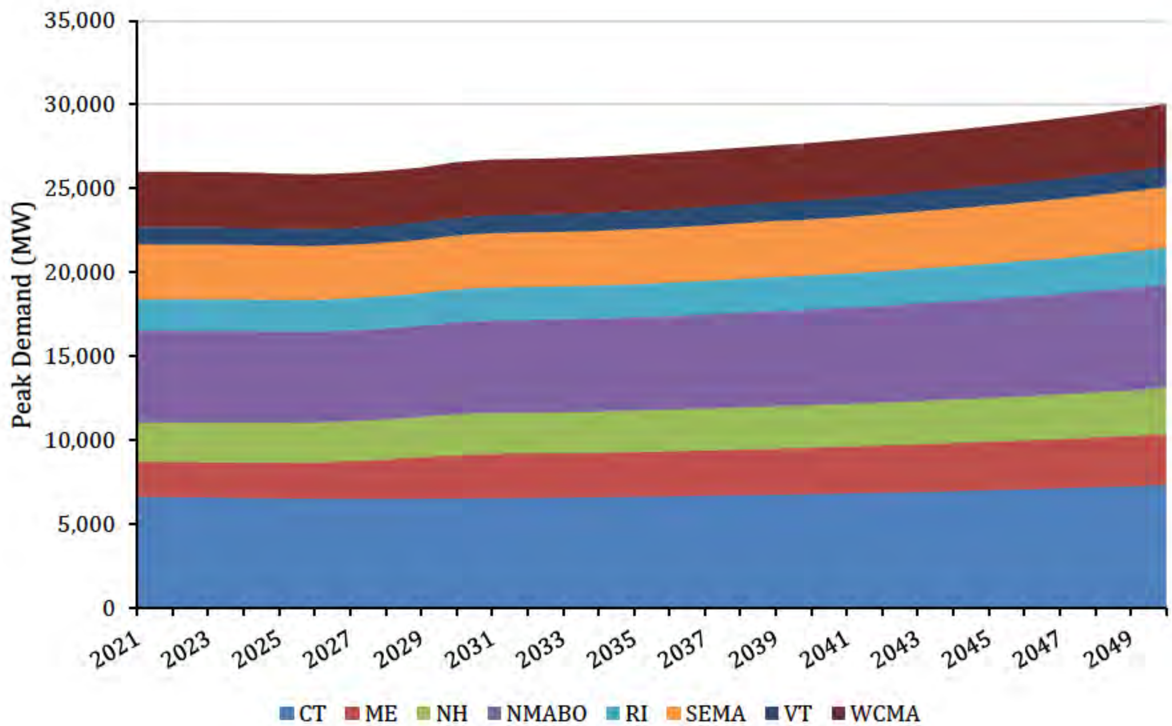

Figure 5. TCR Gross-EE Peak Forecast by State (GW)

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5.2: Hourly Load Shape

In order to simulate the ISO New England market on an hourly basis, TCR requires an hourly load shape for each simulated time frame and area modeled. Figure 6 plots the load shapes used in this model, which is hourly load from 2012. ENELYTIX uses 2012 load profiles in order to align with the 2012 calendar year wind generation profiles used in this model, which represent the most recent detailed data available from NREL for New England.

To develop hourly load forecasts for the entire study period, ENELYTIX calendar-shifts the 2012 load profile to align days of the week and NERC holidays from 2012 to the forecast year. The ENELYTIX algorithm then modifies the calendar shifted template profiles in such a manner that the resulting load shape exhibits the hourly pattern close to that of the template profile while matching monthly total energy and peak load to the monthly energy and peak forecasts.

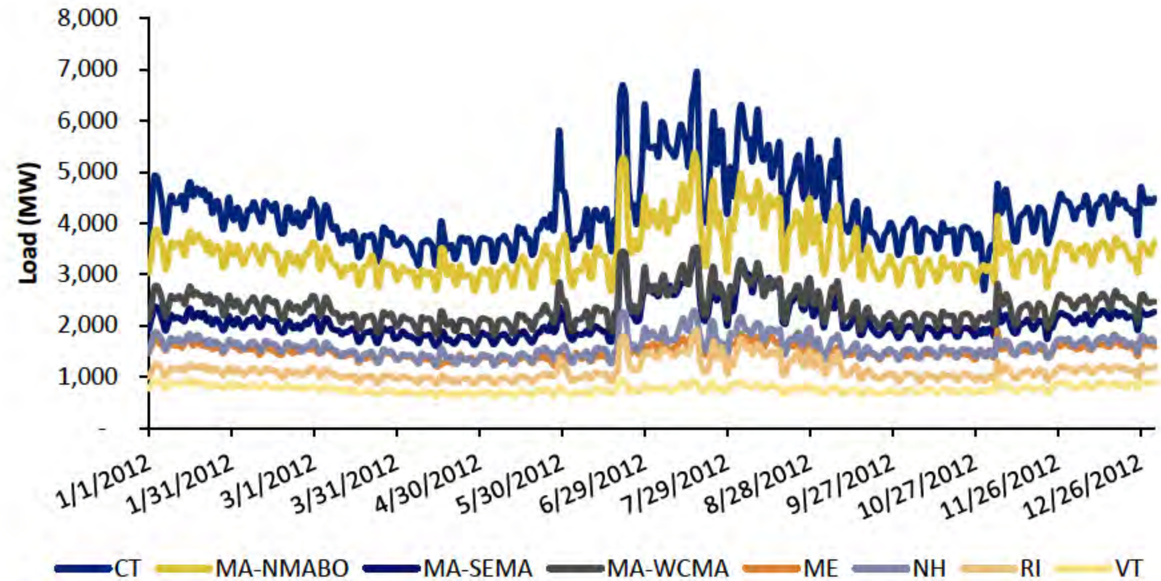

Figure 6. ISO Historical Load Shape, 2012

CHAPTER 6: Ancillary Services

ENELYTIX models four types of Ancillary Services in New England: Regulation, Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve and Thirty-Minute Operating Reserve. Reserves are cascading – excess Regulation counts toward spinning reserves, and excess spinning reserves count toward non-spinning reserves. Non-Spinning reserves can be provided by offline peaking capacity and can handle upward ramping only.

- Regulation must be provided by online resources at the level of ramp rate (in MW/min) limited by a 5-minute activation time.
- Ten-Minute Spinning Reserve must be provided by online resources at the level of ramp rate (MW/min) limited by a 10-minute activation time.
- Ten-Minute Non-Spinning Reserve is provided by offline resources capable of supplying energy within 10 minutes of notices. TMNSR can only be provided by quick-start-capable CTs and Internal Combustion (IC) units.
- Thirty-Minute Operating Reserve can be provided by either on-line or off-line resources with less than 30 minutes activation time.

Hydro units can provide Regulation, Ten-Minute Spinning Reserve, and Thirty-Minute Operating Reserve for up to 5%, 10%, and 30% of its dispatch range, respectively. PV, wind, nuclear, and storage cannot provide ancillary services.

Table 8 summarizes reserve requirements in ISO-NE.

Table 8. ISO-NE Regulation and Reserve Requirements

Reserve Type	Requirement (MW)
Regulation	Hourly schedule per ISO-NE requirements
Ten-Minute Spinning Reserve	820
Ten-Minute Non-Spinning Reserve	820
Thirty-Minute Operating Reserve	750

CHAPTER 7:
Installed Capacity Requirement (ICR)

7.1: Overview

In the Base Case, TCR includes three different ISO-NE capacity requirements:

- System-wide Generating Capacity Requirement (ICR)
- Local Sourcing Requirement (LSR) or import-constrained zones
- Maximum Capacity Limit (MCL) for export-constrained zones

Each of these three requirements are enforced for both the summer and winter. However, since we do not assume changes to the hourly load shape, ISO-NE is a summer peaking system throughout the study period, and thus only the summer requirements are presented in this memo.

7.2: System-wide Generating Capacity Requirement (GCR)

The GCR is based on the system-wide Installed Capacity Requirement (ICR), and is calculated using the following formula:

$$GCR = ICR - Tie\ benefits - OP4 + MinRsv - EE - BTMPV - Others$$

Where:

- **ICR** is the Installed Capacity Requirement, calculated as:
$$ICR = peak\ load\ forecast * (1 + reserve\ margin)$$
- **Tie benefits** represents all capacity tie benefits, including the HQICC
- **OP4** is a voltage reduction relief calculated by ISO-NE for each FCA
- **MinRsv** is the minimum reserve published by ISO-NE for each FCA
- **EE** is past, present, and future energy efficiency measures at the time of peak demand
- **BTMPV** is projected behind-the-meter photovoltaic generation at the time of peak demand
- **Others** includes additional generating capacity that cleared the FCA, including ADRs

The reserve margin for the ICR calculation is an average of reserve margins calculated from previous Forward Capacity Auctions (FCAs) using the following formula:

$$Reserve\ Margin = \frac{ICR + total\ tie\ benefits}{Gross\ Peak\ Load}$$

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Table 9Table 9 summarizes TCR's ISO-NE system-wide GCR requirement in the Base Case:

Table 9. ISO-NE Capacity Requirement

FCA		FCA11	FCA12	FCA13	FCA14	FCA15	TCR Projection					
FCA Period		**2020/21**	**21/22**	**22/23**	**23/24**	**24/25**	**25/26**	**29/30**	**34/35**	**39/40**	**44/45**	**49/50**
FCA Results												
Gross Peak Load	MW	29,601	29,436	29,093	28,838	29,303						
ICR	MW	35,034	34,683	34,719	33,431	34,153						
Gross ICR	MW	36,984	36,703	36,719	35,371	35,888						
(Reserve Margin + 1)	%	125%	125%	126%	123%	122%	124%	124%	124%	124%	124%	124%
Peak Load Forecast-ISONE	MW						29,000	29,846	30,977	31,978	32,979	33,980
Tie Benefit												
HQICCs	MW	959	958	969	941	883	883	883	883	883	883	883
Total Tie Benefits	MW	1,950	2,020	2,000	1,940	1,735	1,735	1,735	1,735	1,735	1,735	1,735
Adjustments												
ADR and other Import Reductions	MW	1,798	1,962	1,993	1,757	1,867	1,858	1,858	1,858	1,858	1,858	1,858
BTMPV Summer Peak	MW						1,261	1,441	1,591	1,704	1,790	1,854
EE	MW						3,472	4,195	4,811	5,171	5,332	5,151
OP4	MW					275	275	275	275	275	275	275
MinRsv	MW					700	700	700	700	700	700	700
ICR	*MW*						*36,016*	*37,067*	*38,471*	*39,715*	*40,958*	*42,201*
Generating Capacity Requirement	*MW*						*27,232*	*27,380*	*28,019*	*28,789*	*29,786*	*31,146*

7.3: Local Sourcing Requirement (LSR) for Import-Constrained Zones

Local Sourcing Requirements are minimum levels of installed capacity that must be procured within an import-constrained zone. The following capacity pools are modeled as import-constrained zones in the Base Case: NEMA/Boston, RI/SEMA, SENE, and CT.

For each of these import-constrained zones, TCR calculates reserve margins from the results of previous FCAs. The reserve margin is calculated as follows:

$$Reserve\ Margin = \frac{Local\ Sourcing\ Requirement\ (LSR) + N1\ Import\ Limit}{Gross\ \frac{90}{10}\ Demand} - 1$$

For each zone, the reserve margin is a simple average of reserve margins calculated using data from previous FCAs, and is held constant throughout the study period.

Using this reserve margin, the LSR is calculated as follows:

$$LSR\ = (RM + 1) * Gross\ \frac{90}{10}\ Peak\ Load - N1\ Import\ Limit - BTMPV - EE$$

Where:

- **RM** is the reserve margin
- **Gross 90/10 Peak Load** is the 90th percentile of the peak load forecast distribution, drawn from the 2021 CELT Report and extrapolated throughout the study period as described in Chapter 5
- **N1 Import Limit** is the N-1 import limit
- **BTMPV** is projected behind-the-meter photovoltaic energy at the time of peak demand
- **EE** is the energy impact of past, present, and future energy efficiency measures at the time of peak demand

Table 10 summarizes TCR's projection of Local Sourcing Requirements for the import-constrained zones.

Table 10. Local Sourcing Requirements for Import-Constrained Zones

Pool	2025/26	2026/27	2027/28	2028/29	2029/30	2034/35	2039/40	2044/45	2049/50
NEMA/Boston	2,031	2,018	2,022	2,038	2,064	2,213	2,391	2,618	2,924
SEMA-RI	4,677	4,654	4,651	4,657	4,673	4,760	4,885	5,061	5,316
SENE	8,246	8,214	8,217	8,241	8,285	8,530	8,839	9,244	9,804
CT	4,769	4,719	4,676	4,647	4,635	4,716	4,886	5,121	5,454

7.3.1: Maximum Capacity Limit and Export-Constrained Zones

In addition to import-constrained zones, ISO-NE identifies export-constrained zones and reports a Maximum Capacity Limit (MCL) for each. In the Base Case, TCR models ME and NNE as

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export-constrained zones. This means that the Base Case model includes Rest-of-Pool (ROP) LSRs for the parts of ISO-NE that exists outside these export-constrained zones, referred to as "All but ME" and "All but NNE".

For "All but ME" and "All but NNE", TCR calculates reserve margins from the results of previous FCAs. The reserve margin is calculated as follows:

$$Reserve\ Margin = \frac{ROP\ LSR + Export\ Limit}{Rest\ of\ Pool\ Gross\ \frac{90}{10}\ Peak\ Load} - 1$$

Where:

- **ROP LSR** = ISO-NE Net LSR – Maximum Capacity Limit
- **Export Limit** is the maximum export from the export constrained zone. This is drawn from FCA data
- **Rest of Pool Gross 90/10 Peak Load** is the peak demand for the part of ISO-NE which exists outside the export-constrained zone

For each zone, the reserve margin is a simple average of reserve margins calculated using data from previous FCAs, and is held constant throughout the study period.

Using this reserve margin, the ROP LSR is calculated as follows:

$$ROP\ LSR\ = (RM + 1) * Gross\ \frac{90}{10}\ ROP\ Peak\ Load - Export\ Limit - BTMPV - EE - tie\ Benefit$$

Where:

- **RM** is the reserve margin
- **EE** is past, present, and future energy efficiency measures at the time of peak demand
- **BTMPV** is projected behind-the-meter photovoltaic generation at the time of peak demand
- **Tie benefits** represents all capacity tie benefits for this zone. This is drawn from FCA data.

Table 11 shows the Rest of Pool LSRs for the two export-constrained zones throughout the study period.

Table 11. ROP LSRs for Export-Constrained Zones

Zone	2025/26	2026/27	2027/28	2028/29	2029/30	2034/35	2039/40	2044/45	2049/50
All but ME	28,242	28,173	28,163	28,196	28,277	28,870	29,645	30,630	31,951
All but NNE	22,827	22,751	22,727	22,744	22,801	23,282	23,933	24,768	25,895

7.4: Contribution of Resources toward ICR

For resources listed in ISO-NE CELT 2021 Generator List as well as scheduled new additions, TCR used the Summer Cleared Capacity based on the results of FCA 15. Units reporting dynamic de-list capacity were assumed to contribute the sum of their cleared capacity and their delist capacity.

For scheduled clean energy procurement additions that did not participate in FCA 12 through 15s, as well as generic resources built by the capacity expansion model, TCR assumed their contribution to ICR based on its analysis of summer cleared capacities in FCA 15. TCR calculated the weighted average ICR contribution (ratio of summer cleared capacity to nameplate capacity) by technology and used this to estimate the capacity contribution for those future additions.

Table 12 below summarizes TCR assumptions of summer and winter capacity contributions.

Table 12. Assumed Summer Capacity Contribution

Technology	Contribution to Capacity - Summer
Combined Cycle	91%
Gas Turbine (peaker)	79%
Internal Combustion (peaker)	84%
Boiler (coal)	97%
Boiler (NG)	83%
Nuclear	96%
Fuel Cell	82%
PV	31%
Onshore Wind	13%
Offshore Wind	32%
RoR hydro	25%
Conventional Hydro	95%
Energy Storage (battery)	100%

CHAPTER 8: Renewable Portfolio Standard (RPS) Requirements

This Chapter describes the forecast requirement for Class 1 RPS resources over the study period.

As described in Chapter 2, TCR configures the ENELYTIX Capacity Expansion Module to model Class 1 RPS requirements and resources for all New England states except Vermont, which does not have a Class 1 RPS requirement equivalent to those of the other five states. Over the study time horizon, TCR expects negligible interaction between secondary tiers and the Class 1 REC markets; only Class 1 requirements are modeled, therefore, in order to project new Class 1 eligible renewable additions and Massachusetts Class 1 REC prices.[4]

With the exception of Vermont, the eligibility criteria for Class 1 RPS programs in each of the New England states have a great deal of overlap, and the resulting high level of "fungibility" of new resources' environmental attributes creates a linkage among the Class 1 REC markets of the other five states. This means that they must all be modeled to project REC prices in each

Figure 7 illustrates the process TCR used to determine state-specific Class 1 RPS energy targets by year for each of the five states.

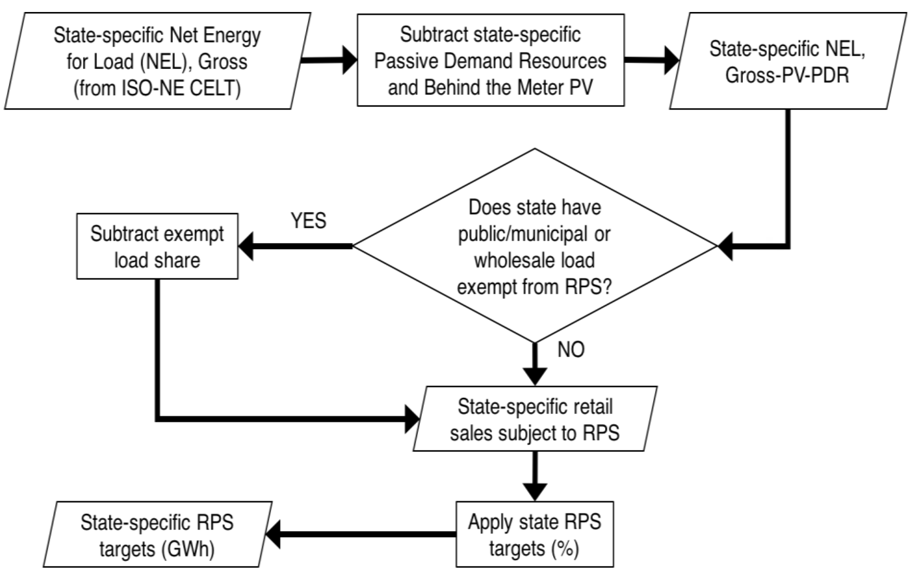

Figure 7. Process Used to Project State-specific RPS Energy Targets

4 The New Hampshire Class II (solar) requirement (0.3 percent of RPS-obligated load) has been added to our Class 1 requirement, given that the distributed solar resources likely to count toward it are included in the distributed PV forecast represented in the model.

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TCR projects RPS requirements using the following data:

- Projections of NEL from Chapter 5.
- Load share for load serving entities (LSEs) and certain wholesale load exempt from state RPS requirements.
- Annual RPS targets for each state[5], expressed as a percentage of sales to end-use customers for obligated (non-exempt) load-serving entities.

For a given state, the forecast requirement for Class 1 RPS energy is equal to the forecast load of LSEs obligated to comply with the RPS multiplied by the annual Class 1 RPS percentage target. The forecast load of LSEs obligated to comply with each RPS is equal to the Gross-PV-EE forecast of NEL by state, reduced by exempt load (Table 13).

Table 13. Exemptions from RPS Obligations

State	Percentage of Load Exempt from RPS Requirements
CT	8.0%
MA*	17.6%
ME	2.8%
NH	1.7%
RI	2.8%
* MA Includes approximately 13.4% exempt retail and 4.2% exempt wholesale load.	

TCR derives the shares of NEL exempt from RPS obligations used in its calculation from state RPS compliance reports, ISO-NE historical NEL data, and EIA data. Table 14 provides a full listing of projected New England RPS requirements.[6]

5 TCR models state RPS targets per regulations as of June 15, 2019. This does not include changes to the Maine RPS target "An Act to Reform Maine's Renewable Portfolio Standard," LD1494, passed on June 26, 2019 (http://legislature.maine.gov/legis/bills/display_ps.asp?PID=1456&snum=129&paper=&paperld=l&ld=1494) . Based on a review of the bill and its implications on the modeling assumptions, the Evaluation Team decided to exclude changes to the Maine RPS target due to uncertainties on implementation details.

6 Sources: (a) Load forecast sourced from the 2021 CELT Report; BTMPV netted from load forecast is extrapolated from ISO-NE Final 2021 PV Forecast, https://www.iso-ne.com/static-assets/documents/2021/03/final_2021_pv_forecast.pdf. (b) Values based on RPS compliance reports, ISO-NE historical NEL data, EIA data, and data provided by MA DOER staff. ME values excludes exemption for PTDZ load after 2031, when that provision sunsets. (d) MA: MGL Ch. 25A, Section 11F, as amended by Chapter 8 of the Acts of 2021, Section 32. https://malegislature.gov/laws/generallaws/parti/titleii/chapter25a/section11f, https://malegislature.gov/Laws/SessionLaws/Acts/2021/Chapter8. CT: Connecticut Renewable Portfolio Standard, Connecticut Public Utilities Regulatory Authority. https://www.ct.gov/pura/cwp/view.asp?a=3354&q=415186 RI: RES Obligation Targets, by Compliance Year, for Both New and Existing Resources, Rhode Island Public Utilities Commission, http://www.ripuc.ri.gov/utilityinfo/RES-Annual-Targets.pdf. NH: SB 129, enacted July 2017. http://gencourt.state.nh.us/bill_status/billText.aspx?sy=2017&id=957&txtFormat=pdf&v=current. ME: Maine Renewable Portfolio Standard, Maine Public Utilities Commission. https://www.maine.gov/mpuc/electricity/RPSMain.htm.

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Table 14. Projected RPS Requirements

(a) Net Energy for Load (NEL) Gross-PV-EE Forecast (GWh)													
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
CT	29,159	29,136	29,173	29,317	29,369	29,540	29,667	29,776	29,889	30,019	30,188	30,351	30,569
MA	58,177	58,553	59,246	60,309	61,166	62,300	62,566	62,796	63,036	63,309	63,666	64,009	64,469
ME	12,457	12,741	13,121	13,583	14,038	14,571	14,633	14,687	14,743	14,807	14,891	14,971	15,079
NH	12,625	12,749	12,904	13,110	13,255	13,440	13,498	13,547	13,599	13,658	13,735	13,809	13,908
RI	8,056	8,101	8,195	8,328	8,449	8,601	8,638	8,670	8,703	8,740	8,790	8,837	8,901
(b) RPS-exempt load as a proportion of NEL													
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
CT	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%
MA	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%
ME	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
NH	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%
RI	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
(c) NEL Subject to RPS Obligations (GWh) = (a) x (1 - b)													
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
CT	26,820	26,799	26,833	26,966	27,014	27,171	27,287	27,388	27,492	27,611	27,767	27,917	28,118
MA	47,931	48,241	48,812	49,687	50,393	51,328	51,547	51,737	51,934	52,159	52,453	52,735	53,115
ME	12,106	12,382	12,751	13,200	13,642	14,160	14,221	14,398	14,453	14,516	14,598	14,676	14,782
NH	12,412	12,534	12,686	12,889	13,031	13,213	13,270	13,319	13,370	13,427	13,503	13,576	13,674
RI	7,832	7,876	7,967	8,096	8,214	8,362	8,398	8,429	8,461	8,497	8,545	8,591	8,653
(d) Class 1 RPS Requirements (%) *													
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
CT	30.0%	32.0%	34.0%	36.0%	38.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
MA	27.0%	30.0%	33.0%	36.0%	39.0%	40.0%	41.0%	42.0%	43.0%	44.0%	45.0%	46.0%	47.0%
ME	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
NH	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%
RI	21.5%	23.0%	24.5%	26.0%	27.5%	29.0%	30.5%	32.0%	33.5%	35.0%	36.5%	36.5%	36.5%
(e) Class 1 RPS Requirements (GWh) = (c) x (d)													
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2,037**
CT	8,046	8,576	9,123	9,708	10,265	10,868	10,915	10,955	10,997	11,044	11,107	11,167	11,247
MA	12,941	14,472	16,108	17,887	19,653	20,531	21,134	21,729	22,332	22,950	23,604	24,258	24,964
ME	1,211	1,238	1,275	1,320	1,364	1,416	1,422	1,440	1,445	1,452	1,460	1,468	1,478
NH	1,949	1,968	1,992	2,024	2,046	2,074	2,083	2,091	2,099	2,108	2,120	2,131	2,147
RI	1,684	1,811	1,952	2,105	2,259	2,425	2,561	2,697	2,834	2,974	3,119	3,136	3,158

* NH Requirement includes Class II solar (0.7%)

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Table 14. Projected RPS Requirements (cont.)

(a) Net Energy for Load (NEL) Gross-PV-EE Forecast (GWh)													
	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
CT	30,763	30,978	31,152	31,361	31,578	31,861	32,113	32,379	32,662	32,949	33,293	33,660	34,036
MA	64,877	65,331	65,700	66,140	66,597	67,193	67,726	68,287	68,882	69,490	70,214	70,988	71,781
ME	15,174	15,280	15,366	15,469	15,576	15,716	15,840	15,972	16,111	16,253	16,422	16,603	16,789
NH	13,996	14,094	14,174	14,269	14,367	14,496	14,611	14,732	14,860	14,991	15,148	15,314	15,486
RI	8,957	9,020	9,070	9,131	9,194	9,277	9,350	9,428	9,510	9,594	9,694	9,801	9,910
(b) RPS-exempt load as a proportion of NEL													
	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
CT	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%
MA	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%
ME	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
NH	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%
RI	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
(c) NEL Subject to RPS Obligations (GWh) = (a) x (1 - b)													
	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
CT	28,295	28,493	28,654	28,846	29,046	29,305	29,538	29,782	30,042	30,307	30,623	30,960	31,306
MA	53,451	53,825	54,128	54,491	54,868	55,359	55,798	56,260	56,751	57,251	57,848	58,485	59,139
ME	14,875	14,979	15,064	15,165	15,270	15,406	15,528	15,657	15,794	15,933	16,099	16,276	16,458
NH	13,760	13,856	13,935	14,028	14,125	14,251	14,364	14,483	14,610	14,738	14,892	15,056	15,224
RI	8,708	8,769	8,818	8,877	8,939	9,019	9,090	9,166	9,246	9,327	9,424	9,528	9,635
(d) Class 1 RPS Requirements (%) *													
	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
CT	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
MA	48.0%	49.0%	50.0%	51.0%	52.0%	53.0%	54.0%	55.0%	56.0%	57.0%	58.0%	59.0%	60.0%
ME	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
NH	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%
RI	36.5%	36.5%	36.5%	36.5%	36.5%	36.5%	36.5%	36.5%	36.5%	36.5%	36.5%	36.5%	36.5%
(e) Class 1 RPS Requirements (GWh) = (c) x (d)													
	2038	2,039	2,040	2,041	2,042	2,043	2,044	2,045	2,046	2,047	2,048	2,049	2,050
CT	11,318	11,397	11,462	11,538	11,618	11,722	11,815	11,913	12,017	12,123	12,249	12,384	12,523
MA	25,657	26,374	27,064	27,790	28,531	29,340	30,131	30,943	31,780	32,633	33,552	34,506	35,483
ME	1,488	1,498	1,506	1,516	1,527	1,541	1,553	1,566	1,579	1,593	1,610	1,628	1,646
NH	2,160	2,175	2,188	2,202	2,218	2,237	2,255	2,274	2,294	2,314	2,338	2,364	2,390
RI	3,178	3,201	3,219	3,240	3,263	3,292	3,318	3,345	3,375	3,404	3,440	3,478	3,517

* NH Requirement includes Class II solar (0.7%)

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8.1: Compliance

Retail electricity sellers are allowed to comply with the RPS using qualified clean energy generation, or by paying an ACP.

TCR models the state specific eligibility of resources based on generation type, size, vintage, commercial operation date, as well as any special eligibility requirements such as those applicable to the eligibility of Biomass units in certain pools. The ENELYTIX capacity expansion model ensures state RPS requirements are met through the most cost-effective combination existing eligible resources, new model build generic renewables, and through the payment of quantity capped ACPs.

By statute, Class 1 RPS ACPs for Rhode Island are indexed to inflation, so in our model they are held constant in real terms at their 2021 levels of $72.51. The Massachusetts value for 2021 is $60 per MWh, decreasing to $40 per MWh by 2023 and then held constant in nominal terms over the study period, which we deflate in real terms over the study period. Similarly, the ACPs in Connecticut and Maine ACP are fixed in nominal terms at $40 and $50 per MWh respectively in 2021, which we deflate in real terms over the study period. New Hampshire's ACP, currently $57.99 per MWh, increases at half the rate of inflation, so for modeling purposes we deflate it in real terms at half the assumed rate of inflation.

Resources located outside ISO-NE provide RECs used to comply with Class 1 RPS obligations in each of the states.. TCR assumes that RECs imported into ISO-NE to comply with Class 1 RPS requirements remain constant at their 2015 levels throughout the study time horizon. TCR estimates the 2015 level, based upon the most recent public data available from state RPS compliance reports and the NEPOOL GIS, to be 2,400 GWh, about 22.8% of the combined 2015 Class 1 requirements.

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CHAPTER 9: Massachusetts Carbon Emission Regulations and Clean Energy Standard

The 83C III Base Case uses the two regulations affecting the electric sector promulgated on August 11, 2017. These are regulation 310 CMR 7.74, a cap on carbon emissions from EGUs located in MA which was re-promulgated without change in December 2020, and regulation 310 CMR 7.75, the CES.

9.1: Cap on Carbon Emissions, Regulation 310 CMR 7.74

The regulation imposes an annual physical cap on CO_2 emissions from EGUs located in the Commonwealth. EGUs are classed as either *New Facilities* or *Existing Facilities*, with separate specific caps on aggregate emissions applicable to EGUs in each category, plus an aggregate cap on emissions from all EGUs (i.e., aggregate cap). Individual EGUs are allowed to use "over-compliance credits" in order to comply with their unit specific limits. **Error! Reference source not found.** presents the limits for new and existing EGUs for select years. The sum of these is the aggregate limit.[7]

Table 15. Aggregate Limits in Select Years, 2025-2040

Year	Aggregate GHG Emissions Limit	Existing Facility Aggregate GHG Emissions Limit	New Facility Aggregate GHG Emissions Limit
2025	7,523,279	6,023,279	1,500,000
2026	7,295,301	6,095,301	1,200,000
2027	7,067,323	5,904,823	1,162,500
2028	6,839,345	5,714,345	1,125,000
2029	6,611,366	5,523,866	1,087,500
2030	6,383,388	5,333,388	1,050,000
. . .	(- 2.5% of 2018 /yr)		

7 Massachusetts Department of Environmental Protection, "BACKGROUND DOCUMENT ON PROPOSED NEW AND AMENDED REGULATIONS: 310 CMR 7.00 and 310 CMR 60.00 Air Pollution Control for Stationary and Mobile Sources," December 16, 2016. **Error! Reference source not found.** is reproduced from Table 3 in this report.

Year	Aggregate GHG Emissions Limit	Existing Facility Aggregate GHG Emissions Limit	New Facility Aggregate GHG Emissions Limit
2035	5,243,497	4,380,997	862,500
2040	4,103,607	3,428,607	675,000
2045	2,963,716	2,476,216	487,500
2050	1,823,825	1,523,825	300,000

The rule defines *New Facilities* as EGUs located in Massachusetts that have less than 10 years operational history as well as those that are scheduled for commissioning during the 2018 – 2025 time period.

Table 16 lists the *Existing Facilities* that are subject to the Existing Facility cap according to Table 4 in the DEP December document.[8]

Table 16. Facility Limits as % of Total Cap

Facility Name	2013-2015 Average Generation (MWh)	% of Total Generation
ANP Bellingham Energy Company, LLC	2,238,927	12%
ANP Blackstone Energy Company, LLC	2,049,400	11%
Bellingham	507,609	3%
Berkshire Power	1,137,483	6%
Canal Station	265,266	1%
Cleary Flood	131,311	1%
Dartmouth Power	125,833	1%
Deer Island Treatment	2,584	0%
Dighton	859,904	4%
Fore River Energy Center	3,236,599	17%
Kendall Square	1,219,559	6%
MASSPOWER	791,485	4%

8 Ibid, p. 39.

Facility Name	2013-2015 Average Generation (MWh)	% of Total Generation
Medway Station	4,172	0%
Milford Power, LLC	387,564	2%
Millennium Power Partners	1,723,289	9%
Mystic	3,945,784	21%
Pittsfield Generating	208,106	1%
Potter (Braintree Electric)	63,569	0%
Stony Brook	179,176	1%
Tanner Street Generation	95,400	0%
Waters River	4,131	0%
West Springfield	39,933	0%

9.2: Clean Energy Standard, Regulation 310 CMR 7.75

The regulation requires retail electricity sellers, excluding Municipal Light Plants (MLPs), to procure CECs or pay the Clean Energy Standard (CES) ACP. The affected retail electricity sellers are investor-owned distribution companies providing standard offer service and competitive energy suppliers. CECs are denominated in megawatt hours (MWh). The quantity of CECs that sellers are required to use to satisfy their obligations each year is a specified percentage of their electricity sales, expressed in MWh. Table 17 presents our forecast of CES requirements over the study period. This forecast is based on the NEL (Gross-PV-EE) from Chapter 5, and an assumption regarding CES-exempt load.

9.2.1: Compliance

Retail electricity sellers are allowed to comply with the CES using RPS Class 1 RECs, using CECs from DEP-qualified new clean energy generation, or by paying an ACP. By statute, the CES ACP is set at 50% of the Class 1 ACP for 2021-2050. The rule contains provisions specifying resource eligibility and banking of CECs. Under the CES, eligible imports from new clean energy generation from Canada must be imported through a dedicated transmission line with a commercial operation date after 2017.

In the 83C III Base Case, compliance with the CES is not enforced as a constraint in the Capacity Expansion optimization. The annual cost of compliance, however, is quantified in a post-

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modeling calculation as the product of any shortfall in meeting a given year's target and the CES ACP for that year. [9]

9 More precisely, the ACP is modeled in the 83C III Base Case as a soft constraint with a very small cost of $0.01/MWh, so that compliance with the CES can be easily tracked, and the cost accounted for afterward.

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Table 17. CES Requirements, 2025 to 2050[10]

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
(a) Net Energy for Load (NEL) Forecast for MA (GWh)	58,177	58,553	59,246	60,309	61,166	62,300	62,566	62,796	63,036	63,309	63,666	64,009	64,469
(b) CES- and RPS-exempt load as a proportion of NEL (%)	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%
(c) NEL Subject to CES and RPS Obligations (GWh) = (a) x (1 - b)	47,931	48,241	48,812	49,687	50,393	51,328	51,547	51,737	51,934	52,159	52,453	52,735	53,115
(d) CES Requirements (%)	30.0%	32.0%	34.0%	36.0%	38.0%	40.0%	42.0%	44.0%	46.0%	48.0%	50.0%	52.0%	54.0%
(e) CES Requirements (GWh) = (c) x (d)	14,379	15,437	16,596	17,887	19,149	20,531	21,650	22,764	23,890	25,036	26,227	27,422	28,682
(f) MA Class 1 RPS Requirements (%)	27.0%	30.0%	33.0%	36.0%	39.0%	40.0%	41.0%	42.0%	43.0%	44.0%	45.0%	46.0%	47.0%
(g) MA Class 1 RPS Requirements (GWh) = (c) x (f)	12,941	14,472	16,108	17,887	19,653	20,531	21,134	21,729	22,332	22,950	23,604	24,258	24,964
(h) CES Incremental to RPS (%) = max[(d)-(f), 0]	3.0%	2.0%	1.0%	0.0%	0.0%	0.0%	1.0%	2.0%	3.0%	4.0%	5.0%	6.0%	7.0%
(i) CES Incremental to RPS (GWh) = max[(e)-(g), 0]	1,438	965	488	0	-	0	515	1,035	1,558	2,086	2,623	3,164	3,718
	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
(a) Net Energy for Load (NEL) Forecast for MA (GWh)	64,877	65,331	65,700	66,140	66,597	67,193	67,726	68,287	68,882	69,490	70,214	70,988	71,781
(b) CES- and RPS-exempt load as a proportion of NEL (%)	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%
(c) NEL Subject to CES and RPS Obligations (GWh) = (a) x (1 - b)	53,451	53,825	54,128	54,491	54,868	55,359	55,798	56,260	56,751	57,251	57,848	58,485	59,139
(d) CES Requirements (%)	56.0%	58.0%	60.0%	62.0%	64.0%	66.0%	68.0%	70.0%	72.0%	74.0%	76.0%	78.0%	80.0%
(e) CES Requirements (GWh) = (c) x (d)	29,933	31,218	32,477	33,785	35,116	36,537	37,943	39,382	40,860	42,366	43,964	45,618	47,311
(f) MA Class 1 RPS Requirements (%)	48.0%	49.0%	50.0%	51.0%	52.0%	53.0%	54.0%	55.0%	56.0%	57.0%	58.0%	59.0%	60.0%
(g) MA Class 1 RPS Requirements (GWh) = (c) x (f)	25,657	26,374	27,064	27,790	28,531	29,340	30,131	30,943	31,780	32,633	33,552	34,506	35,483
(h) CES Incremental to RPS (%) = max[(d)-(f), 0]	8.0%	9.0%	10.0%	11.0%	12.0%	13.0%	14.0%	15.0%	16.0%	17.0%	18.0%	19.0%	20.0%
(i) CES Incremental to RPS (GWh) = max[(e)-(g), 0]	4,276	4,844	5,413	5,994	6,584	7,197	7,812	8,439	9,080	9,733	10,413	11,112	11,828

10 Sources: (a) Load forecast sourced from "Energy Pathways to Deep Decarbonization, A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study," (December 2020), as cited in "Massachusetts Decarbonization Roadmap," December 2020; represents load growth of the Pipeline Gas scenario. https://www.mass.gov/doc/energy-pathways-for-deep-decarbonization-report/download. BTMPV netted from load forecast is extrapolated from ISO-NE Final 2021 PV Forecast, https://www.iso-ne.com/static-assets/documents/2021/03/final_2021_pv_forecast.pdf; (b) Based on ISO-NE historical NEL data, EIA data, and data provided by MA DOER staff for 2019. Includes exempt municipal load (14.2% of retail sales, 13.4% of NEL) and exempt wholesale load (large exempt end users). (d) 310 CMR 7.75 Clean Energy Standard. https://www.mass.gov/doc/310-cmr-775-clean-energy-standard-amendments-july-2020/download (f) MGL Ch. 25A, Section 11F, as amended by Chapter 8 of the Acts of 2021, Section 32. https://malegislature.gov/laws/generallaws/parti/titleii/chapter25a/section11f, https://malegislature.gov/Laws/SessionLaws/Acts/2021/Chapter8.

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CHAPTER 10: Generation Mix

10.1: Existing Generation Capacity

TCR uses the existing generating units listed in the ISO-NE 2021 CELT Report, tab 2.1, Generator list.[11]

10.2: Scheduled Retirements

Table 18 summarizes the ISO-NE approved scheduled retirements. TCR obtains this list of retirements from the ISO-NE Retirement Tracker, and cross-references these retirements against S&P Global's data services.[12] Mystic units 8 and 9 are assumed to retire after the termination of their cost of service agreement with ISO-NE expires on May 31, 2024. [13] The Salem Harbor plant is also assumed to retire in 2050 based on the settlement agreement between the plant owners and the Conservation Law Foundation. [14]

Table 18. ISO-NE Approved Capacity Retirements

CELT Asset ID	Name	Energy Area	Generation/Fuel Type	Summer Capacity (MW)	Retire Date
Retirements Per ISO-NE retirement Tracker					
340	BRIDGEPORT HARBOR 3	CT	Coal	400	6/1/2021
341	BRIDGEPORT HARBOR 4	CT	IC/GT	17	6/1/2024
324	CDECCA	CT	CC	63	6/1/2024
376	CLEARY 8	SEMA	ST	25	6/1/2024
502	MYSTIC 7	NMABO	ST	512	6/1/2022
503	MYSTIC JET	NMABO	IC/GT	9	6/1/2022
531	PAWTUCKET POWER	RI	CC	54	6/1/2022
556/557/558	SCHILLER 4,5,6	NH	Coal	100	6/1/2024
572/573/574/575	SO. MEADOW 11-14	CT	IC/GT	146	6/1/2023
633	WEST SPRINGFIELD 3	WCMA	ST	92	6/1/2024
Long Term Nuclear Retirements					
484	MILLSTONE POINT 2	CT	NUC	864	7/1/2035
485	MILLSTONE POINT 3	CT	NUC	1206	11/1/2045
555	SEABROOK	NH	NUC	1248	3/1/2050
Assumption-Based Retirements					

11 https://www.iso-ne.com/static-assets/documents/2021/04/2021_celt_report.xlsx
12 https://www.iso-ne.com/static-assets/documents/2016/08/retirement_tracker_external.xlsx
13 https://www.exeloncorp.com/newsroom/statement-regarding-the-retirement-of-mystic-generating-station-in-2024
14 https://www.clf.org/wp-content/uploads/2014/02/Final-Settlement-Agreement-2_18_20142.pdf. The retirement of the unit is also accompanied by an emissions cap starting at 2,279,530 tons/year in 2025 declining to 528,874 tons/year in 2049.

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CELT Asset ID	Name	Energy Area	Generation/Fuel Type	Summer Capacity (MW)	Retire Date
1478/1616	MYSTIC 8,9	NMABO	CC	1413	6/1/2024
48695/48696	SALEM 5,6	NMABO	CC	675	1/1/2050

10.3: Scheduled Additions

TCR included near term generator additions based on recently signed or awarded Clean Energy Procurements based on information provided by the EDCs. In addition, TCR included units having cleared the Forward Capacity Auctions 13-15 covering additions from 2022 through 2024.

10.3.1: Near Term Class 1 Renewable Resource Additions

TCR assumes addition of renewable generation projects selected under recent clean energy RFPs that are contracted to commence operation after 2021. Table 19 summarizes the procurements whose contracted additions are included in the model.[15]

Table 19. Additions from New England Clean Energy RFP

Program	Technology	Approximate Nameplate Capacity (MW)
CT Small Scale RFP (2017)	PV	220
Tri-state RFP (2017)	PV, Wind	330
MA 83D (2017/18)	Hydro	1,090
MA 83C I (2018/19)	Offshore Wind	800
CT Clean Energy RFP (2018)	Fuel Cell, Offshore Wind	252
RI ACES (RW400) (2019)	Offshore Wind	400
CT Zero Carbon RFP (2018/19)	PV, Offshore Wind	248
MA 83C II (2019/20)	Offshore Wind	804
RI LTCS (2019/20)	PV	50
CT OSW Procurement I (2020/21)	Offshore Wind	804
ME RPS 1A RFP I (2020)	PV, Wind, Hydro	546
ME RPS 1A RFP II (2021)	PV, Wind, Hydro	422

15 Details of individual contracts were provided to TCR by the EDCs and are not reported due to confidentiality.

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10.3.2: Capacity Additions Based on the Forward Capacity Auction (FCA)

Table 20 summarizes projected near-term new generation additions, which are greater than 10 MW and have cleared the latest Forward Capacity Auction (FCA) completed as of June 2021.[16,17]

Table 20. Scheduled Individual Generation Capacity Additions (>10 MW)

FCA ID	Name	Energy Area	Type	Summer ICAP (MW)	In effect / COD
Upgrades to existing units					
359/360	J. COCKWELL 1 & 2	WCMA	PSH	583(+80)	6/1/2021
New additions per FCA 13-15 (excludes units procured under contract)					
40883	KCE CT 1	CT	ES	200	6/1/2024
40884	KCE CT 2	CT	ES	20	6/1/2023
41573	Milford Grid_LLC	CT	ES	300	6/1/2024
40912	South Portland BESS	ME	ES	10	6/1/2023
40919	Resource Cross Town	ME	ES	175	6/1/2024
41566	Great Lakes Millinocket	ME	ES	20	6/1/2024
40666	Cranberry Point Battery Energy Storage	SEMA	ES	150	6/1/2024
40907	Cross Road BESS	SEMA	ES	246	6/1/2023
40915	Medway Grid_LLC	SEMA	ES	250	6/1/2024
40943	Cahoon Grid_LLC	SEMA	ES	150	6/1/2023
40729	Ballston Grid_LLC	WCMA	ES	150	9/1/2023
44172	RJOL Hydro	ME	Hydro	10	6/1/2024
38663	Killingly Energy Center	CT	CC	632	6/1/2022
38692	MMWEC Simple Cycle Gas Turbine	NMABO	IC/GT	58	6/1/2021
40732	Three Corners Solar	ME	PV	77	6/1/2022

**Units < 10 MW are not shown in the table (In total, 37 MW Energy Storage, 57 MW Solar PV and 7.5 MW thermal)*

10.3.3: Distributed PV Resources

Because distributed PV development is largely driven by policies other than the Class 1 RPS requirements—such as Solar Massachusetts Renewable Target ("SMART") and the Small Scale Renewable Energy Growth and Renewable Energy Fund programs in Rhode Island—TCR uses the 2021 CELT Report to project distributed PV additions, rather than add them using the Capacity Expansion model in response to the market.[18] All distributed PV generation additions through 2030 in the ISO-NE PV Forecast are assumed in the Base Case to come to fruition. TCR forecasted distributed PV for the remainder of the study horizon by extrapolating the ISO-NE PV Forecast using a curve fit.

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16 https://irtt.iso-ne.com/reports/external

17 https://www.iso-ne.com/isoexpress/web/reports/auctions/-/tree/fcm-auction-results

18 ISO New England Final 2021 PV Forecast, March 22nd, 2021 ("ISO-NE PV Forecast"). The PV forecast includes detailed estimates of installations in each state, developed in conjunction with those states. The projected new entry is primarily policy-driven, but includes a post-policy component; both components embody explicit realization rates that vary over the period.

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The forecast breaks PV into two types—behind the meter (BTMPV), and non-BTM distributed PV. Non-BTM PV are allowed to provide energy and capacity, whereas BTMPV can only provide energy. Non-BTM PV resources are assumed to provide a contribution to ICR at a level equal to the contribution factor assumed for PV resources. In representing the Massachusetts RPS rules in the Capacity Expansion module, TCR assumes that all distributed PV energy can count against or reduce the Class 1 RPS requirement.[19] TCR assumes distributed PV in Vermont counts toward the Vermont Distributed Generation (Tier 1) requirement (not represented in our model), and do not allow it to count toward Class 1 requirements elsewhere.

10.4: Capacity Expansion Generation Additions

The capacity expansion module chooses from a predefined list of potential future generation resources to satisfy resource adequacy and environmental constraints. There are two categories of generation resources that can be added by the capacity expansion module. The first category includes the fossil-fuel based conventional sources of generation that are built in discrete increments based on the size and attributes of the reference unit. The second category includes variable renewable resources such as wind and photovoltaic that the model can build in varying size increments up to their resource potential. Additionally, the capacity expansion module can add battery storage.

10.4.1: Cost assumptions for Capacity Expansion Model Generic Additions

10.4.1.1: Capital Cost Assumptions

Table 21**Error! Reference source not found.** below summarizes the potential resource types that TCR has available in its capacity expansion model. The capacities indicated for variable resources are for reference only, and additional performance characteristics of thermal units are described in **Error! Reference source not found.** of this report.

- Generic fossil fuel resource additions include dual-fuel capable combined cycle and simple cycle gas turbine generating units. For these technologies, TCR relies on unit characteristics and cost assumptions as specified in the Concentric Energy Advisors' (CEA) report prepared for ISO-NE; filed with FERC in support of its application for the FCA16 parameters.[20]. **Error! Reference source not found.**Table 21 presents capital and operating cost assumptions for generic market-driven fossil resource additions.
- Nuclear additions are not allowed to be built by the capacity expansion model.
- Generic renewable resources include behind the meter and utility scale PV, onshore and offshore wind, run-of-the-river hydropower as well as biopower resources. The costs for some of these technologies were included in the ISO-NE study which were benchmarked against costs available from the EIA Annual Energy Outlook 2021 cost assumptions[21] and NRELs ATB 2020[22].

19 Reducing the requirement (as in the Solar Carve-outs) or being counted toward it (as in the SMART program) are effectively the same thing from a modeling perspective.

20 https://www iso-ne.com/static-assets/documents/2021/02/a02_mc_2021_02_24_cea_adendum.docx

21 https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

22 https://atb.nrel.gov/electricity/2020/data.php

Costs not available from the ISO-NE study were sourced from EIA, and if those were not available, from NREL.

- Generic 4 hour battery storage is allowed to be built by the capacity expansion model without a hard cap on the available potential.

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Table 21. Potential Resource Additions

Resource Category	Technology Details	Source of Cost	Capacity (MW)	Heat Rate (BTU/kWh)	Overnight Capital Cost (2021$/kW)	Fixed O&M (2021$/kW-year)	Variable O&M (2021$/MWh)
Combined Cycle Gas Turbine	GE 7HA.02 Single shaft with Duct Firing	ISONE CONE and ORTP	557.0	5,796	$987.50	$66.30	$3.60
Simple Cycle Frame Gas Turbines	GE 7HA.02	ISONE CONE and ORTP	376.0	8,168	$766.70	$47.90	$4.63
Simple Cycle Aeroderivative	GE LM6000PF+	ISONE CONE and ORTP	98.0	8,679	$1,760.30	$90.40	$5.14
Biomass (solid)	50-MW Biomass Plant Bubbling Fluidized Bed	EIA Cost Assumptions	44.0	13,500	$4,938.80	$153.00	$4.95
Biomass (Gas)	Landfill Gas 4 x 5.6 MW	EIA Cost Assumptions	18.0	8,513	$1,747.30	$22.50	$6.35
Hydro	Conventional Hydropower	NREL	211.0	-	$7,537.00	$47.00	$0.00
PV	20 MW Fixed Mount in New England	ISONE CONE and ORTP	20	-	$1,572.50	$29.50	$0.00
	Distributed Residential Fixed tilt roof mounted	NREL	0.005	-	$3,208.60	$23.10	$0.00
Wind	82.5 MW Vestas V150-5.6MW Turbines; Central New Hampshire	ISONE CONE and ORTP	82.5	-	$2,163.80	$46.90	$0.00

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Resource Category	Technology Details	Source of Cost	Capacity (MW)	Heat Rate (BTU/kWh)	Overnight Capital Cost (2021$/kW)	Fixed O&M (2021$/kW-year)	Variable O&M (2021$/MWh)
Offshore Wind	800 MW; MA Offshore Wind Lease Area	ISONE CONE and ORTP	800.0	-	$5,984.00 / $4,188.80[23]	$129.00	$0.00
Energy Storage	85% round trip efficiency	NREL	50.0	-	$1,715.50	$42.90	$0.00

23 Offshore Wind has a 30% lower capital cost through 2035, reflecting the Investment Tax Credit (ITC).

10.4.1.2: Impact of PTC / ITC on costs

The impact of both the Production Tax Credit (PTC) and Investment Tax Credit (ITC) are included in capacity expansion and reflect the extension of those credits per the Taxpayer Certainty and Disaster Tax Relief Act of 2020.[24]

Table 22. Summary of PTC / ITC[25]

Construction Year	Utility PV			Onshore wind			Offshore wind		
	ITC	PTC	COD Assumed	ITC	PTC	COD Assumed	ITC	PTC	COD Assumed
2018	30%	N/A	2020	18%	60%	2022	30%	60%	2028
2019	30%	N/A	2021	12%	40%	2023	30%	40%	2029
2020	26%	N/A	2022	18%	60%	2024	30%	60%	2030
2021	26%	N/A	2023	18%	60%	2025	30%	60%	2031
2022	26%	N/A	2024	N/A	N/A	2026	30%	N/A	2032
2023	22%	N/A	2025	N/A	N/A	2027	30%	N/A	2033
2024	10%	N/A	2026	N/A	N/A	2028	30%	N/A	2034
2025	10%	N/A	2027	N/A	N/A	2029	30%	N/A	2035
2026 & later	10%	N/A	2028 & later	N/A	N/A	2030 & later	N/A	N/A	2036 & later

The PV includes a 10% ITC reduction which is assumed to persist throughout the study period. This reduction is already reflected in the capital cost of utility scale PV per the source document. Onshore wind coming online by 2025 is assumed to receive the PTC at 40% stepdown. Offshore wind built through 2035 is assumed to have 30% lower capital cost, reflecting a 30% ITC. After 2035, the capital cost will revert back to the original value. All existing onshore wind facilities are assumed to receive a 10-year PTC starting from its COD at the appropriate stepdown based on an assumed four year difference between construction and operation.

10.4.1.3: Financial Assumptions for Generic Resource Additions

The base case uses common financing assumptions for all market-driven unit additions, both fossil fuel and renewable. These assumptions include a 20-year financing period, and a real after tax weighted average cost of capital (WACC) of 6.0%. The WACC is based on the results of an analysis by Concentric Energy Advisors prepared for ISO New England, which assumes uncontracted merchant development, and is based on costs of equity and debt that are commensurate with a merchant project's perceived risks of cost recovery in the market, which are higher than those of a project whose revenues are contracted under a PPA.[26] The use of a WACC based on merchant rather than contracted development reflects the Base Case assumption that only merchant development will be possible

24 taxpayer certainty and Disaster tax relief act of 2020 https://www.finance.senate.gov/imo/media/doc/Tax,%2012-21-20,%20Section%20by%20Section%20Taxpayer%20Certainty%20and%20Disaster%20Tax%20Relief%20Act%20of%202020.pdf
25 PTC References: NREL https://atb.nrel.gov/electricity/2021/financial_cases_&_methods,
26 ISO-NE CONE and ORTP Analysis. Concentric Energy Advisors. Prepared for ISO New England, January 13, 2017, p. 48.

because the market will not bring about the development of resources with long-term PPAs in the absence of mandated procurements such as 83C.

10.4.2: Maximum Resource Potentials

10.4.2.1: Fossil-Fuel Generator Additions

For thermal generation additions, TCR assumes that new buildable capacity in each area is approximately two times the current installed thermal capacity in that area. TCR assumes that each zone has access to at least one thermal unit of each fossil fuel technology type listed in Table 21Table and models multiple units of each in order to meet the zones target requirement.

10.4.2.2: Renewable Generator Additions

TCR relies on NREL assessments of renewable resource potentials and uses data available on NREL's geospatial toolkits and associated publications to establish upper limits on various model-built variable resources for each energy area within the ISO-NE footprint.

Although NREL's resource potentials are typically available by state[27], TCR obtained more granular county level data to re-aggregate state potentials into potentials by energy areas. The methodologies for calculating potentials are described below:

- **Onshore wind and photovoltaic**: potentials for onshore wind and PV are obtained from NRELs REV study[28]. Granular county level data for annual energy and nameplate capacity for onshore wind, PV, and concentrated solar power were obtained directly from NREL. The potentials were aggregated to obtain potentials by energy zone and reduced by the quantity of PV and onshore wind already existing in the ISO-NE model.
- **Rooftop PV:** potentials are obtained from NRELs Solar For All Toolkit[29] which provides an estimate of annual energy that may be obtained through rooftop PV installations by county. Annual energy is converted to nameplate capacity using energy area specific capacity factors to obtain nameplate potential for rooftop PV. Finally, the potential of rooftop PV is reduced by the quantity of rooftop PV already existing in the ISO-NE model.
- **Offshore wind and Hydropower**: potentials for offshore wind and hydropower by state are obtained from NREL's GIS-based technical potential study[30].

  For offshore wind, TCR assumed distributions of state potentials to each of the energy areas proportionate to the length of the coastlines. The offshore wind potentials are reduced by the quantity of existing offshore wind in the ISO-NE model.

  For Hydropower, TCR assumed similar distributions of state potentials to each of the energy areas proportionate to their approximate footprints. Since the assessment of Hydropower

27 Renewable Energy Technical Potential. https://www nrel.gov/gis/re-potential html
28 Renewable Energy Potential (reV) Model. https://www.nrel.gov/docs/fy19osti/73067.pdf
29 Solar for All Data Explorer. https://maps nrel.gov/solar-for-all/?aL=0&bL=clight&cE=0&lR=0&mC=38.870832155646326%2C-98.34521484375001&zL=5
30 U.S. Renewable Energy Technical Potentials: A GIS Study. https://www nrel.gov/docs/fy12osti/51946.pdf

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potential is on a site-specific basis it is assumed to already account for hydropower that has already been built.

- **Biopower**: potentials for biogas and biomass are obtained from NRELs biopower geospatial toolkit[31] which provides annual estimates of tons per year of biomass and biogas resources by county. Conversion factors to annual energy and nameplate capacity are available within the toolkit to obtain the nameplate potential for biomass and biogas resources.

Table 23 provides the final modeled resource potentials for variable resources by ISO-NE energy area.

Table 23. Technical Potential for Installed Renewable Capacity by Resource Type and State (MW)

Zone	Rooftop PV	Hydro	Biogas	Offshore Wind	Utility PV	Biomass	Onshore Wind
CT	3,890	211	8,550	14,342	40,542	44	2,887
ME	1,588	894	2,853	294,836	839,220	130	53,311
NH	1,500	397	3,802	6,912	65,718	54	10,439
NMABO	4,985	62	3,340	129,006	20,145	43	150
RI	1,082	14	1,902	41,930	22,440	13	217
SEMA	1,621	61	4,273	239,146	49,741	17	671
VT	797	835	478	-	51,990	28	17,967
WCMA	1,849	150	1,908	-	31,257	25	3,995
ISONE Total	*17,312*	*2,624*	*27,106*	*726,172*	*1,121,053*	*354*	*89,637*

10.5: Capacity Expansion Unit Retirement

Over the study period ENELYTIX analyzes the economics of existing thermal units to determine whether their projected revenues compared to their projected variable operating costs justifies retiring any of those units. The ENELYTIX capacity expansion optimization algorithm evaluates the trade-off between the need to keep the generating unit online to meet resource adequacy requirements against making an investment into another generating unit to satisfy environmental constraints and/or producing energy at lower operating cost.

31 Biopower Atlas. https://maps.nrel.gov/biopower/?aL=wyQpUn%255Bv%255D%3Dt&bL=clight&cE=0&lR=0&mC=40.21244%2C-91.625976&zL=4

CHAPTER 11:
Generating Unit Operating Characteristics

11.1: Generator Aggregation

To optimize model computation time, TCR aggregates all units below 20 MWs by type, fuel and load zone into a smaller set of units. Full load heat rates for the aggregates are calculated as the capacity-weighted average of the individual units and all other parameters are inherited from the unit type.

11.2: Thermal Unit Characteristics

Thermal generation characteristics are generally determined by a generator's technology and fuel type. These characteristics include heat rate curve shape, non-fuel operation and maintenance costs, startup costs, forced and planned outage rates, minimum up and down times, and quick start, regulation and spinning reserve capabilities.

TCR developed generator outage and heat rate data from information by similar unit type as obtained from both the North American Electric Reliability Corporation (NERC) Generating Availability Report and power industry data provided by S&P Global.

Each thermal unit type has a distinct normalized incremental heat rate curve. The normalized heat rate curve is scaled by the full load heat rate (FLHR) to produce unit specific heat curve. Table 24 summarizes the shape of normalized heat rate curves used in ENELYTIX.

Table 24. Normalized Incremental Heat Rate Curve

Unit Type	Blocks (Total)	Block	Capacity Range (% of Max)	Heat Rate (% of FLHR)
CT	1	1	100%	100%
CC	4	1	50%	113%
		2	51% ~ 67%	75%
		3	68% ~ 83%	86%
		4	84% ~ 100%	100%
ST (Coal)	4	1	0% ~ 50%	106%
		2	51% ~ 65%	90%
		3	66% ~ 95%	95%
		4	96% ~ 100%	100%
ST (Other)	4	1	25%	118%
		2	26% ~ 50%	90%
		3	51% ~ 80%	95%
		4	81% ~ 100%	100%

As an example, for a 500 MW CC with a 7,000 Btu/KWh FLHR, the minimum load block would be its minimum generation of 250 MW at a heat rate of 7,910 Btu/KWh, the 2nd incremental block would be 251 MW ~ 335 MW at a heat rate of 5,250 Btu/KWh, the 3rd increment would be 336 MW ~ 415 MW at a heat rate of 6,020 Btu/KWh, and the final block would be 416 MW ~ 500 MW at a heat rate of 7,000 Btu/KWh.

Table 25 summarizes other operating parameter assumptions by unit type for thermal generators. The abbreviations in the unit type column are structured as follows: First 2-3 characters identify the technology type, the next 1-2 characters identify the fuel used (**g**as, **o**il, **c**oal, **b**iomass, **r**efuse) and the numbers identify the size of generating units mapped to that type.

Table 25. Other Thermal Unit Operating Parameters by Unit Type

Unit Type	Min On Time (Hr)	Min Off Time (Hr)	EFORd (%)	VOM ($/MWh)	Startup Cost Cold ($/MW-start)
CCg100 (0-100MW)	6	8	4.29	2.5	35
CCg100+ (100-9999MW)	6	8	4.29	2.5	35
CCgo100 (0-100MW)	6	8	4.29	2.5	35
CCgo100+ (100-9999MW)	6	8	4.29	2.5	35
Cco+ (0-9999MW)	6	8	8.58	2.5	35
CCr+ (0-500MW)	1	1	4.29	2.5	35
GTb20 (0-20MW)	1	1	11.28	10	--
GTg20 (0-20MW)	1	1	18.6	10	--
GTg50 (20-50MW)	1	1	12.97	10	--
GTgo20 (0-20MW)	1	1	18.6	10	--
GTgo50 (20-50MW)	1	1	12.97	10	--
GTgo50+ (50-9999MW)	1	1	9.29	10	--
GTo20 (0-20MW)	1	1	18.6	10	--
GTo50 (20-50MW)	1	1	12.97	10	--
GTo50+ (50-9999MW)	1	1	9.29	10	--
GTo20 (0-20MW)	1	1	18.6	10	--
GTo50 (20-50MW)	1	1	12.97	10	--
GTr20 (0-20MW)	1	1	11.28	10	--
ICb+ (0-500MW)	1	1	11.63	10	--
ICg20 (0-20MW)	1	1	21.16	10	--
ICg50+ (50-500MW)	1	1	11.54	10	--
ICgo20 (0-20MW)	1	1	21.16	10	--
ICgo50 (20-50MW)	1	1	11.54	10	--
ICgo50 + (50-500MW)	1	1	11.54	10	--
ICo20 (0-20MW)	1	1	21.16	10	--
ICo50+ (50-500MW)	1	1	11.54	10	--
ICog20 (20-50MW)	1	1	11.54	10	--
ICo50 (0-50MW)	1	1	11.54	10	--
ICr+ (0-500MW)	1	1	11.63	2	--
NUC-BWR1000MW+	164	164	2.19	0	90
NUC-BWR(800-1000MW)	164	164	1.66	0	90

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Unit Type	Min On Time (Hr)	Min Off Time (Hr)	EFORd (%)	VOM ($/MWh)	Startup Cost Cold ($/MW-start)
NUC-BWR(400-799MW)	164	164	3.27	0	90
NUC-PWR1000MW+	164	164	4.02	0	90
NUC-PWR(400-799MW)	164	164	3.02	0	90
STb+ (0-500MW)	10	8	10.26	0	35
STc100 (0-100MW)	24	12	8.32	5	45
STc250 (100-250MW)	24	12	6.47	4	45
STc600 (250-600MW)	24	12	7.83	3	45
STg100 (0-100MW)	10	8	10.34	6	40
STg200 (100-200MW)	10	8	8.42	5	40
STg600 (200-600MW)	10	8	8.35	4	40
STgo100 (0-100MW)	10	8	10.34	6	40
STgo200 (100-200MW)	10	8	8.42	5	40
STgo600 (200-600MW)	10	8	8.35	4	40
STo100 (0-100MW)	10	8	10.34	6	40
STo200 (100-200MW)	10	8	8.42	5	40
STo600 (200-600MW)	10	8	8.35	4	40
STo600+ (600-9999MW)	10	8	14.55	3	40
STr+ (0-500MW)	10	8	10.26	2	40

11.2.1: Nuclear Unit Operating Characteristics

Nuclear plants are modeled as special thermal units in ENELYTIX. In general, nuclear facilities are treated as must run units and assumed to run except for periods during generator maintenance and forced outage. Current refueling schedules are obtained from roadtech.com[32]. Future schedules are estimated per specified periodicity.

11.3: Hydro Electric Generator Characteristics

TCR models hydro electric generators as energy constrained generators that output energy in relation to daily pattern of water flow, i.e. the minimum and maximum generating capability and the total energy for each plant. TCR obtains historic hydro generation MWh from EIA and S&P Global database. Based on this historic information, TCR develops daily maximum energy output for each hydro power plant in ISO-NE. Subject to this maximum energy output constraint, TCR allows ENELYTIX® to optimize hourly energy output of each hydro electric generator to minimize system-wide production costs in each hour of the day.

11.4: Pumped Hydro Storage Facilities

32 https://www.roadtechs.com/shutdown/shutdown.php?region=n

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TCR models pumped storage with the following specifications obtained from the National Hydroelectric Power Resource Study prepared for the U.S. Army Engineer Institute of Water Resources.

- Max Storage: Unit Capacity * Number of Storage hours
- Min Storage: 10% of Max Storage
- Min MW: Pumping Capacity
- Efficiency: Annual Output/Annual Pumping Energy

11.5: Wind Facilities

Wind generation is represented as hourly generation profile in ENELYTIX®. TCR assembles wind generation profiles from the National Renewable Energy Laboratory (NREL)'s Wind Integration National Dataset (WIND) Toolkit dataset based on 2012 weather data.[33] TCR maps each wind power plant to the nearest NREL site based on the plant's location. For wind plants with known historic capacity factor, TCR further screens for NREL wind sites that have capacity factor within delta of 2% from historical average capacity factor inside a 50-mile radius range from the plant's location. The resulting normalized NREL site schedule is scaled to the installed capacity of the corresponding wind site and then calendar-shifted for each forecast year making it synchronized with load profiles and interchange schedules.

11.6: Solar Photovoltaics Facilities

Like wind facilities, photovoltaic (PV) generators are also represented as hourly generation profiles in ENELYTIX®. TCR obtains solar irradiation data from the weather station closest to a PV generator's location and uses NREL's PVWatts® Calculator to estimate the site's energy production. TCR assumes all utility scale PV facilities are fixed array installations with characteristics summarized in Table 26.

Table 26. Photovoltaic Parameter Assumptions

PV Parameter	Assumption
Elevation (m)	5
Module Type	Standard
Array Type	Fixed (Open Rack)
Array Tilt (deg)	20
Array Azimuth (deg)	180
System Losses (%)	14
Invert Efficiency (%)	96

33 https://www.nrel.gov/grid/wind-toolkit.html

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CHAPTER 12: Fuel Prices

12.1: Natural Gas Prices

12.1.1: Spot Gas Prices in New England

TCR obtained a monthly spot gas price forecast for natural gas market hubs from Wood Mackenzie.[34] However, a proper modeling of price diversity among gas-fired generators serving ISO-NE requires forecasts for more hubs than are provided in the Wood Mackenzie outlook. To extend the Wood Mackenzie forecast to the required hubs, TCR obtained historic spot price data for each relevant hub for the past 5 years. Using historic spot price data, for each relevant hub in the ISO-NE region TCR identified the highest price-correlated hub which had a Wood Mackenzie forecast and calculated a percentage difference in the historic spot price between the two hubs.

The projections of natural gas spot prices at each market hub equals the Wood Mackenzie projection of Henry Hub price plus the Wood Mackenzie projection of monthly basis differential to each market hub from the Henry Hub. For hubs with no Wood Mackenzie forecast, the spot price equals the projection at the highest-correlated hub with a Wood Mackenzie forecast, multiplied by the percentage difference in price between the hubs from the historic spot price data. Forecasted ISO-NE market hub and Henry Hub prices are shown in Figure 8.

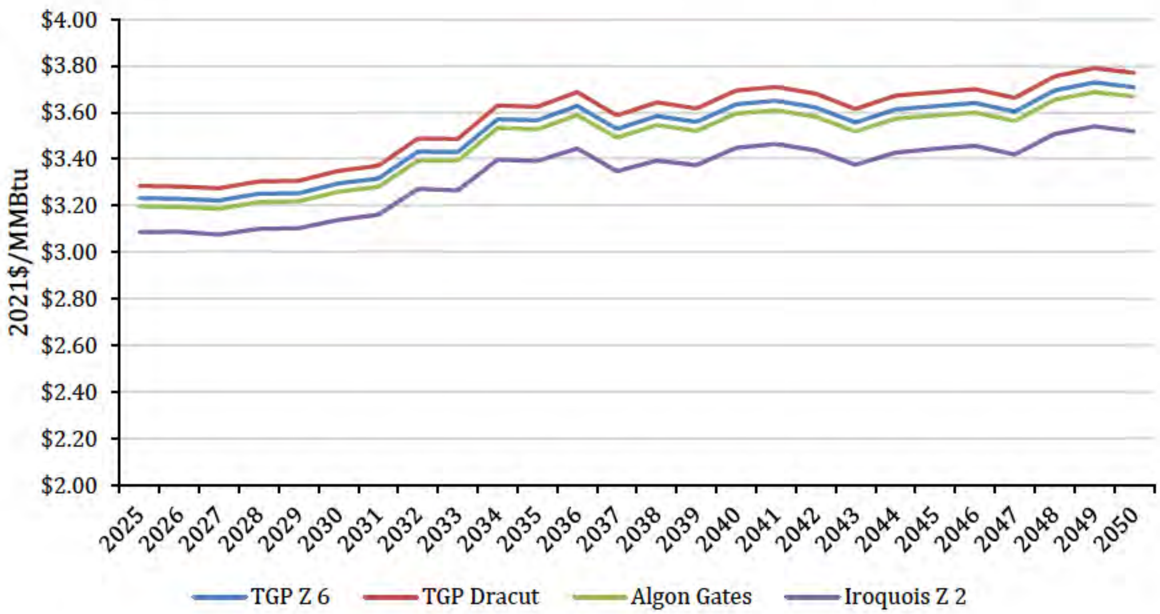

Figure 8. TCR Forecasted Yearly Spot Natural Gas Prices in ISO-NE ($2021/MMBTU)

34 North America gas 2021 outlook to 2050. Wood Mackenzie

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Figure 9 shows the TCR forecast of monthly spot prices at natural hubs serving ISO-NE. This figure indicates that the TCR forecast of gas prices to electric generating units shows significant variation between winter months and summer months.

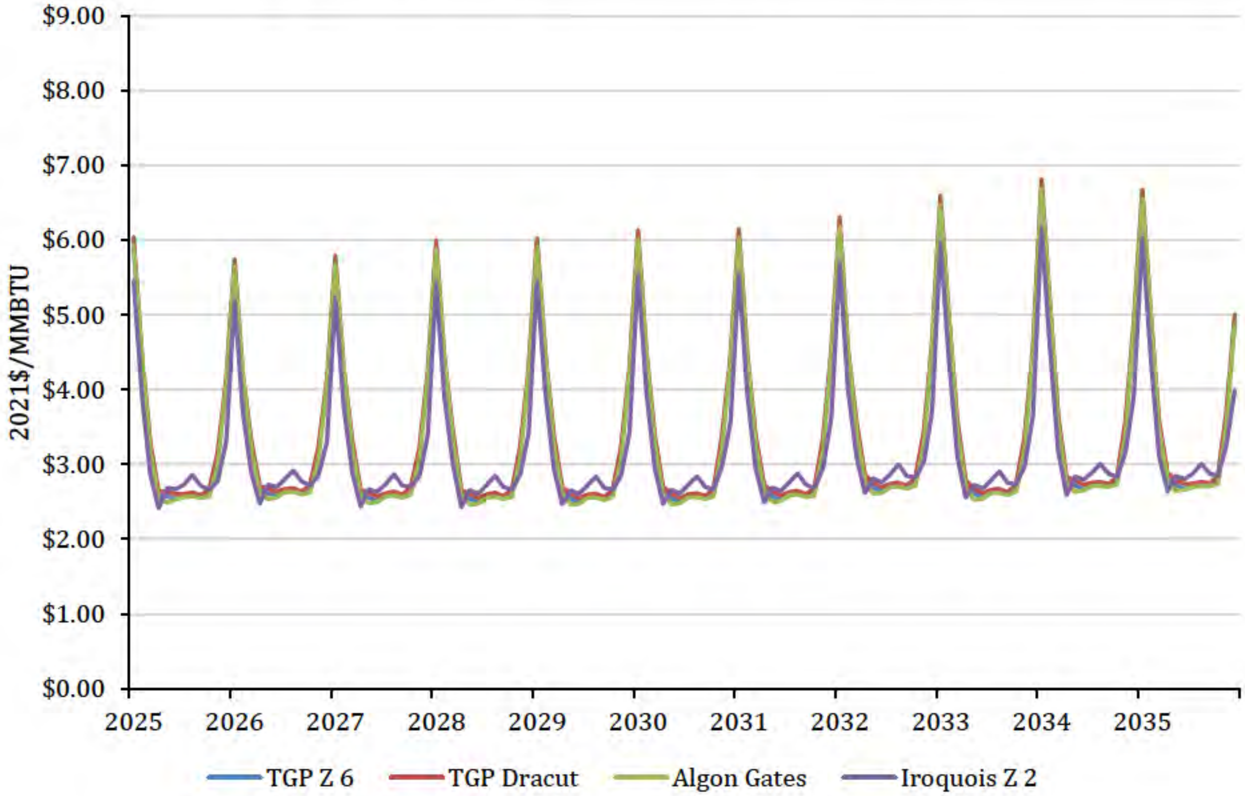

Figure 9. TCR Forecasted Monthly Spot Natural Gas Prices in ISO-NE ($2021/MMBTU)

12.1.2: Natural Gas Price Adders

TCR adds plant level fuel prices adders for all natural gas fired power plants based on each power plants' supplier type (pipeline connected vs. LDC served) and unit type (baseload units vs peaking units). These adders are shown in Table 27.

Table 27. Natural Gas Power Plant Fuel Adders ($/MMBtu)

Unit Type	Directly Connected to Pipeline	Served by LDC
Baseload Units	0.05	0.2
Peaking Units	0.15	0.4

12.2: Prices of Distillate and Residual Fuel Oil for Electric Generation in New England.

TCR obtained annual crude oil projections from Wood Mackenzie's North America gas 2021 outlook to 2050.[35] In order to extend these projections to distillate (No. 2) and residual (No. 6) fuel oil, TCR used historic fuel prices obtained from the EIA. TCR calculated price ratios between the fuel oils and crude oil using a five-year historical monthly average for the daily spot prices for crude oil (Cushing, OK WTI) and No. 2 heating oil (NY Harbor spot price), and the monthly U.S. Residual Fuel Oil wholesale price.

The projections for No. 2 fuel oil (FO2) and No. 6 fuel oil (FO6) equal the Wood Mackenzie forecast for crude oil multiplied by the historic price ratios. The projection of fuel oil prices is shown in Figure 10.

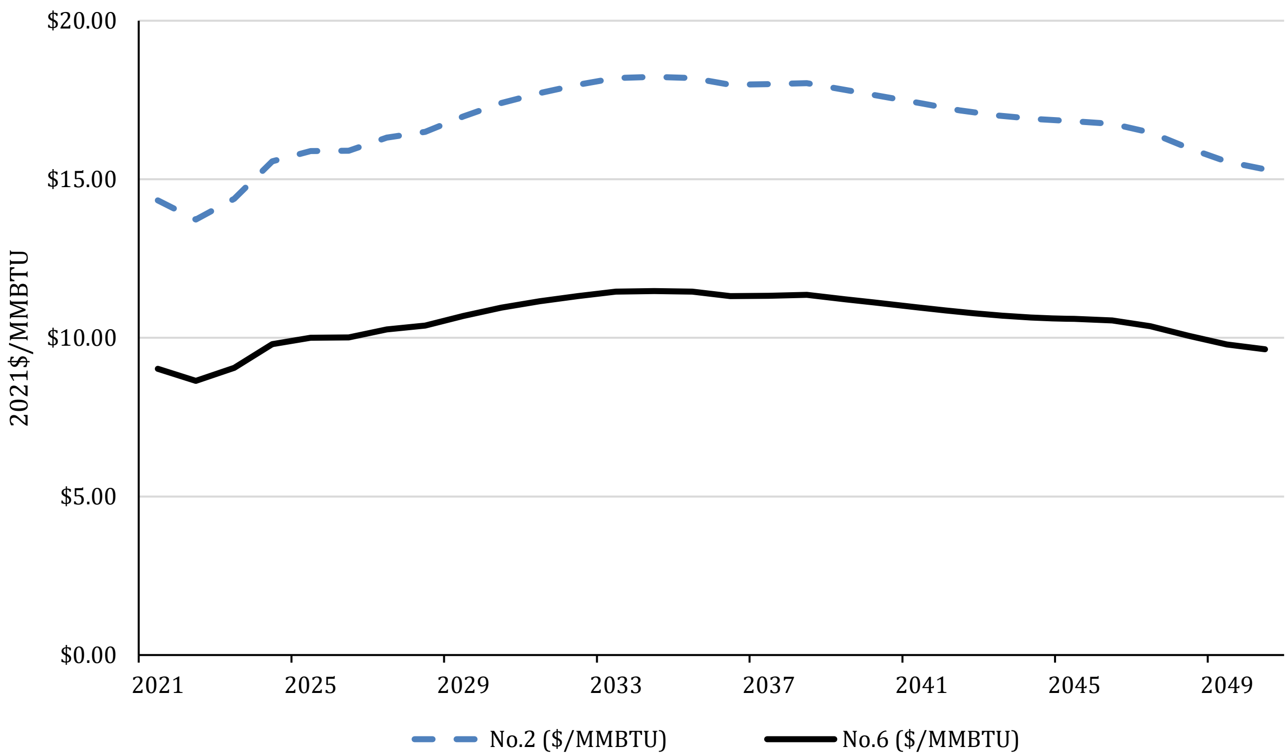

Figure 10. TCR Projection of Fuel Oil Price ($2021/MMBTU)

12.3: Winter Fuel Switching for Dual Fuel Generators

Because of natural gas pipeline supply constraint in New England, generators often experience gas shortages in extreme winter days. During gas shortage days, dual fuel generators switch fuel from natural gas to fuel oil due to economic reasons and/or operational requirements. TCR modeled winter fuel switching to approximate the economic and environmental impact resulting from dual fuel generators switching from natural gas to fuel oil on winter days with high natural gas prices. Details of

35 North America gas gas 2021 outlook to 2050. Wood Mackenzie

the fuel switching methodology used to capture the daily volatility in winter gas prices is described in Attachment C of the 83C III Stage Two Quantitative Evaluation Protocol.

12.4: Uranium Prices

TCR develops uranium prices using the pricing calculator created by the Bulletin of the Atomic Scientist[36]. The calculator estimates the cost of electricity assuming the nuclear fuel cycle is "Once-Through". TCR omits all capital related cost associated with the cost of electricity from the calculator. The resulting uranium price is 0.99 Nominal $/MMBtu, which TCR assumed to be fixed.

12.5: Coal Prices

TCR develops plant level coal price from S&P Global's power plant operations data base. TCR derives coal cost in $/MMBtu by dividing S&P Global reported annual cost of coal delivered ($/ton) by annual average heat content of coal burned (Btu/lbs.). Based on this method, TCR calculates the exact coal cost for plants where data is available. For plants without sufficient data, TCR assumes the average cost from other coal plants in the same area and/or state.

TCR developed coal cost for this project using coal price data by plant from S&P Global Services and converted said prices to real 2021$/MMBtu. TCR assumes the prices reported in will remain at those levels over the study period. Table 28 shows the prices used for the three coal units present in the ISO-NE Base Case during the 2025-2050 study period.

Table 28. Base Case Coal Prices in ISO-NE

Unit	Price (2021$/MMBTU)
MERRIMACK 1	$3.92
MERRIMACK 2	$3.92
ND PAPER	$2.00

36 http://thebulletin.org/nuclear-fuel-cycle-cost-calculator/model

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CHAPTER 13: Emission Rates

13.1: Emission Rates

TCR obtains generator unit level emission rates from three sources: S&P Global's historic unit emissions data base, S&P Global's simulated Generator Supply Curve (GSC) data base and EIA's generic future unit characteristics. For existing thermal units, TCR uses S&P Global's historic emission rates. For existing units without historic data, TCR uses GSC emissions data. Finally, for existing units without historic and GSC data, and future units not yet operating, TCR uses EIA's generic rates.

13.2: Regional Greenhouse Gas Initiative (RGGI)

All states in ISO-NE participate in the Regional Greenhouse Gas Initiative (RGGI). TCR developed its RGGI CO_2 allowance price assumptions based on the Wood Mackenzie 2021 gas outlook to 2050, which includes a RGGI price forecast.[37] Figure 11 plots the Base Case RGGI price assumption.

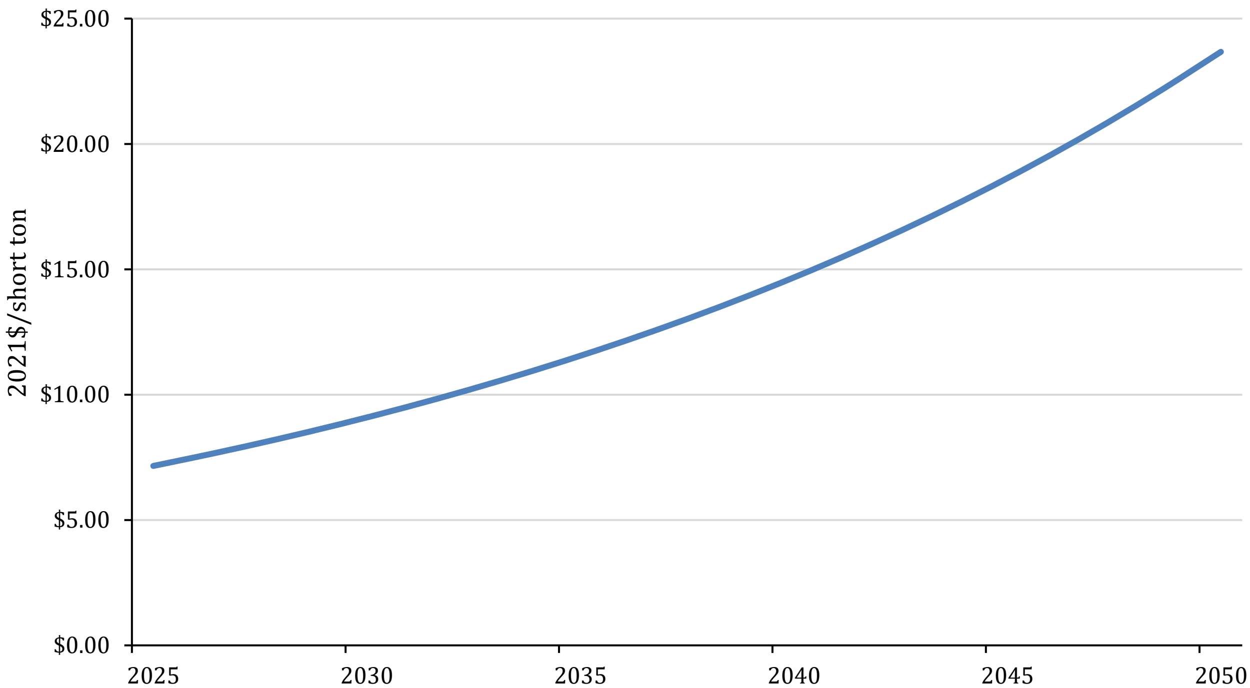

Figure 11. RGGI Price Projection, 2025-2050 (2021$/short ton)

37 North America gas gas 2021 outlook to 2050. Wood Mackenzie

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TCR assumed allowance prices of zero for NOx and SO_2 emissions. The Federal Cross State Air Pollution Rule (CSAPR) establishes NO_x and SO_2 emission limits, and no New England state has emission limits under CSAPR. Therefore, CSAPR allowance prices are not applicable to New England generators.

SO_2. With the retirement of Brayton Point, SO_2 emissions in New England have dropped to levels near zero and correspondingly we assume zero value for SO_2 allowances for the applicable state acid rain programs.

NOx. In accordance with Governor Baker's Executive Order 562 and to meet federal Clean Air Act requirements, MA DEP in August 2016 proposed to replace the Massachusetts Clean Air Interstate Rule (310 CMR 7.32) with a new Ozone Season Nitrogen Oxides Control (310 CMR 7.34). The rule was intended to meet a 2017 (and beyond) budget for NO_x emissions from large fossil-fuel-fired electric power and steam generating units during the ozone season (May 1st through September 30th). The proposed Massachusetts Ozone Season NO_x budget is 1,799 tons. NOx ozone season emissions from all sources have been decreasing, and over the past five years have ranged between 975 and 1,620 tons. As a result, we ascribe zero value to NO_x allowances in Massachusetts.

On September 9, 2016, US EPA approved a State Implementation Plan revision submitted by Connecticut. This revision continues to allow facilities to create and/or use emission credits using NO_x Emission Trading and Agreement Orders (TAOs) to comply with the NO_x emission limits required by RCSA section 22a-174-22 (Control of Nitrogen Oxides), which imposes emissions rate limits on generators. It is possible that under this rule NO_x DERCs, or allowances, will have value to certain individual generators. Lacking evidence of a liquid market or visible pricing for such allowances in Connecticut, we are assuming their value to be zero.

GLOSSARY

Term	Definition
ACP	Alternative Compliance Payments
ADR	Active Demand Response
AEO	Annual Energy Outlook
AESC	Avoided Energy Supply Cost
ALG	Algonquin
BIO	Biomass
BMPV/ BTMPV	Behind-the-meter Photovoltaic
CC	Combined Cycle
CEA	Concentric Energy Advisors
CEC	Clean Energy Credits
CECP	Clean Energy and Climate Plan
CEII	Critical Energy Infrastructure Information
CELT	Capacity, Energy, Loads, and Transmission
CES	Clean Energy Standard
CMR	Code of Massachusetts Regulations
COD	Commercial Operation/Online Date
CSAPR	Cross-State Air Pollutions Rule
CT	Combustion Turbine
CT PURA	Connecticut Public Utilities Regulatory Authority
DA	Day-ahead
DER	Distributed Energy Resources
DERC	Discrete Emission Reduction Credits
DFO/NO. 2	Distillate Fuel Oil
DPU	Department of Public Utilities
E&AS	Energy and Ancillary Services
EDC	Electric Distribution Company

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Term	Definition
EE	Energy Efficiency
EEA	Energy and Environmental Affairs
EFORd	Effective Forced Outage Rates
EGU	Electric Generating Units
EIA	Energy Information Administration
eNodes	Electrical Nodes
EPA	Environmental Protection Agency
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FLHR	Full Load Heat Rate
GCR	Generating Capacity Requirement
GIS	Geographic Information System
GHG	Greenhouse Gas
GSC	Generator Supply Curve
GT	Gas Turbine
GWSA	Global Warming Solutions Act
HD	Hydro Power
HVDC	High Voltage Direct Current
IC	Internal Combustion (reciprocating) Engine
ICAP	Installed Capacity
ICR	Installed Capacity Requirements
ITC	Investment Tax Credit
Kirchhoff's laws	The current law and the voltage law
LDC	Load Distribution Company
LMP	Locational Marginal Price
LSE	Load Serving Entity
LSR	Local Sourcing Requirement

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Term	Definition
MA DEP	Massachusetts Department of Environmental Protection
MCL	Maximum Capacity Limit
MinRsv	Minimum Reserve
MIP	Mixed Integer Programming
MLP	Municipal Light Plant
MMD	Market Model Database
NECEC	New England Clean Energy Connect
NEL	Net Energy Load
NEPOOL GIS	New England Power Pool Generation Information System
NERC	North American Electric Reliability Corporation
NG	Natural Gas
NREL	National Renewable Energy Laboratory
PDR	Passive Demand Response
PME	Power Market Explorer
PPA	Power Purchase Agreement
PSH	Pumped Storage Hydro Unit
PSO	Power System Optimizer
PTC	Production Tax Credit
PV	Photovoltaic
PVWatts®	NREL's PV Calculator
RCSA	Regulations of Connecticut State Agencies
REC	Renewable Energy Certificate, Renewable Energy Credit
REV	Renewable Energy Potential (reV) Model
RFO/NO. 6	Residual Fuel Oil
RFP	Requests for Proposal
RGGI	Regional Greenhouse Gas Initiative
RM	Reserve Margin
RMR	Reliability Must Run

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Term	Definition
ROP	Rest of Pool
RPS	Renewable Portfolio Standard
RT	Real-time
SCED	Security Constrained Economic Dispatch
SCUC	Security Constrained Unit Commitment
SENE	Southeast New England
SMART	Solar Massachusetts Renewable Target
ST	Steam Turbine
SUN	Solar Powered
TAO	Trading and Agreement Orders
TARA tool	Transmission Adequacy & Reliability Assessment tool
TMNSR	Ten-Minute Non-Spinning Reserve
TMOR	Thirty-Minute Operating Reserve
TMSR	Ten-Minute Spinning Reserve
VOM	Variable Operation & Maintenance
WACC	Weighted average cost of capital
WAT	Water
WIND (NREL)	Wind Integration National Dataset
WT	Wind Turbine

APPENDIX A: ENELYTIX

This Appendix describes the computer model and analytical capability TCR uses to support the evaluation of 83C II Proposed Clean Energy Projects.

A.1: ENELYTIX® and Power System Optimizer (PSO)

ENELYTIX®[38] is a cloud based energy market simulation environment implemented on Amazon EC2 commercial cloud.

A central element of ENELYTIX is the Power System Optimizer ("PSO"), an advanced simulator of power markets. PSO provides ENELYTIX the capability to accurately model the decision processes used in a wide range of power planning and market structures including long-term system expansion, capacity markets, Day-ahead energy markets and Real-time energy markets. ENELYTIX has this capability because it can configure PSO to determine the optimum solution to each market structure. Figure A-1 illustrates the four key components of the PSO analytical structure: Inputs, Models, Algorithms and Outputs.

As a system expansion optimization model, PSO integrates resource adequacy requirements with the specific design of the capacity market and with the environmental compliance policies, such as state-level and regional Renewable Portfolio Standards (RPS) and emission constraints.

As a production cost model, PSO is built on a Mixed Integer Programming (MIP) based unit commitment and economic dispatch structure that simulates the operation of the electric power system. PSO determines the security-constrained commitment and dispatch of each modeled generating unit, the loading of each element of the transmission system, and the locational marginal price (LMP) for each generator and load area. PSO supports both hourly and sub hourly timescales. In this project, the PSO is set up to model unit commitment (DA market) and an economic dispatch (RT market). In the commitment process, generating units in a region are turned on or kept on in order for the system to have enough generating capacity available to meet the expected peak load and required operating reserves in the region for the next day. PSO then uses the set of committed units to dispatch the system on an hourly real-time basis, whereby committed units throughout the modeled footprint are operated between their minimum and maximum operating points to minimize total production costs. The unit commitment in PSO is formulated as a mixed integer linear programming optimization problem which is solved to the true optima using the commercial CPLEX solver.

As an FCM Capacity Market Model, PSO is configured to simulate the outcome of the ISO-NE's Forward Capacity Auction subject to market specific rules and parameters develop projections of capacity prices.

38 ENELYTIX® is a registered trademark of Newton Energy Group, LLC.f

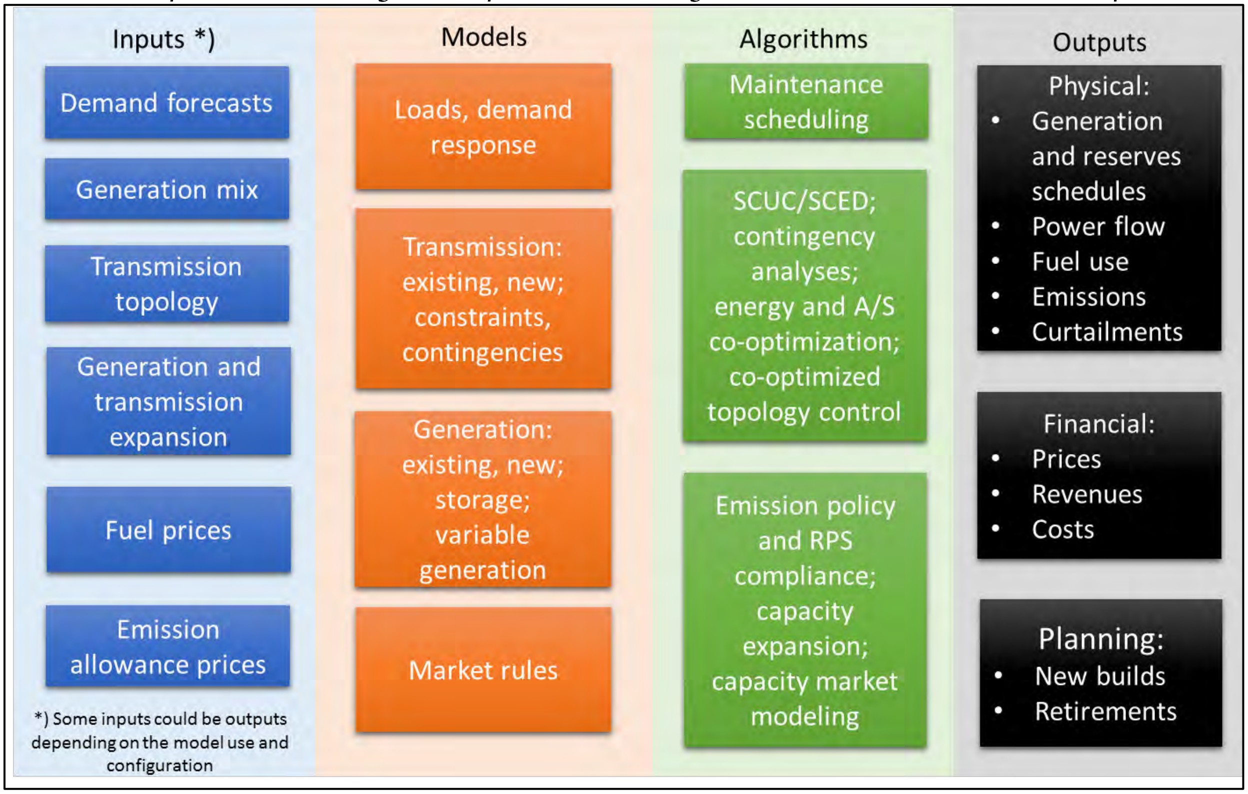

Figure A-1. Analytical Structure of PSO

The ENELYTIX/PSO modeling environment provides a realistic, objective and highly defendable analyses of the physical and financial performance of power systems, in particular power systems integrating variable renewable resources. The critical advantage of PSO over traditional production costing modeling tools is its ability to model the concurrent dynamics of:

- uncertainty of future conditions of the power system;
- the scope, physical capabilities and economics of options available to the system operator to respond to these uncertain conditions;
- the timing and optionality or irreversibility of operator's decisions to exercise these options.

By capturing these concurrent dynamics, ENELYTIX/PSO avoids the generally recognized inability of traditional simulation tools to reflect the effect of operational decisions on the physics of the power system, price formation and financial performance of physical and financial assets.

A.1.1: Modeling the Impact of Uncertainty

System operators deal with a number of uncertainties in the data they use for their day-ahead decisions that ultimately impact operations and prices in the real-time market. These uncertainties typically include differences between forecast and actual load; forecast and actual output of variable generation; and forecast versus actual generation and transmission outages.

ENELYTIX/PSO offers the most realistic representation of the impact of those uncertainties between day-ahead decisions and real-time dispatch. ENELYTIX/PSO provides information, data structures and algorithms necessary for the realistic representation of these uncertainties including different load shapes and wind patterns for modeling the Day-ahead and Real-time markets. It also has embedded methods for incorporating forecast errors if explicit forecasts are not available, and model representation of time points at which the system becomes aware of generator outages.

System operators' options for responding to these uncertainties include (1) generation commitment decisions based on day-ahead and intra-day reliability assessments, (2) forward-looking procurement of ancillary services and (3) deployment of reserves when uncertainty is realized. ENELYTIX/PSO provides unique capabilities to model the process by which system operators rely on these options. The model allows the user to specify the decision timing and (at each decision point) to determine classes of decisions that are still provisional and can be revisited at a later stage, and classes of decisions that are final and therefore irreversible. These capabilities are critical for an accurate representation of forward commitments, actual dispatch decisions, curtailments, emergence of scarcity events and corresponding price formation. The ENELYTIX/PSO represents these concurrent dynamics through the use of the decision cycle logic and rolling horizon optimization.

A.1.2: ENELYTIX modeling architecture

ENELYTIX provides the advanced modeling features of PSO and the scalability of cloud computing. With the ENELYTIX cloud-based architecture, TCR can generate, simulate and post process a large number of Cases in a matter of hours. What we can turn around in an hour competing models require 10 days.

Figure A-2 illustrates the ENELYTIX architecture. This figure highlights the system services that support parallel processing of simulation projects. As shown in that figure, a Project consists of Tasks. Each Task is a collection of Cases, and each Case is partitioned into Segments which could be processed in parallel. In ENELYTIX, implementation of a Task *is a single-click* experience. Once the Task is launched, it invokes a process in which all user requested Cases are generated at once out of the Market Model Database (MMD) pre-populated with model data. Cases are formed by specifying alternative versions of inputs (e.g. alternative supply options or portfolios of such options, load forecast, new entry and retirement assumptions or fuel price sensitivities, types and requirements for ancillary services and myriads of other alternatives the user may need to explore and compare against each other within the same task).

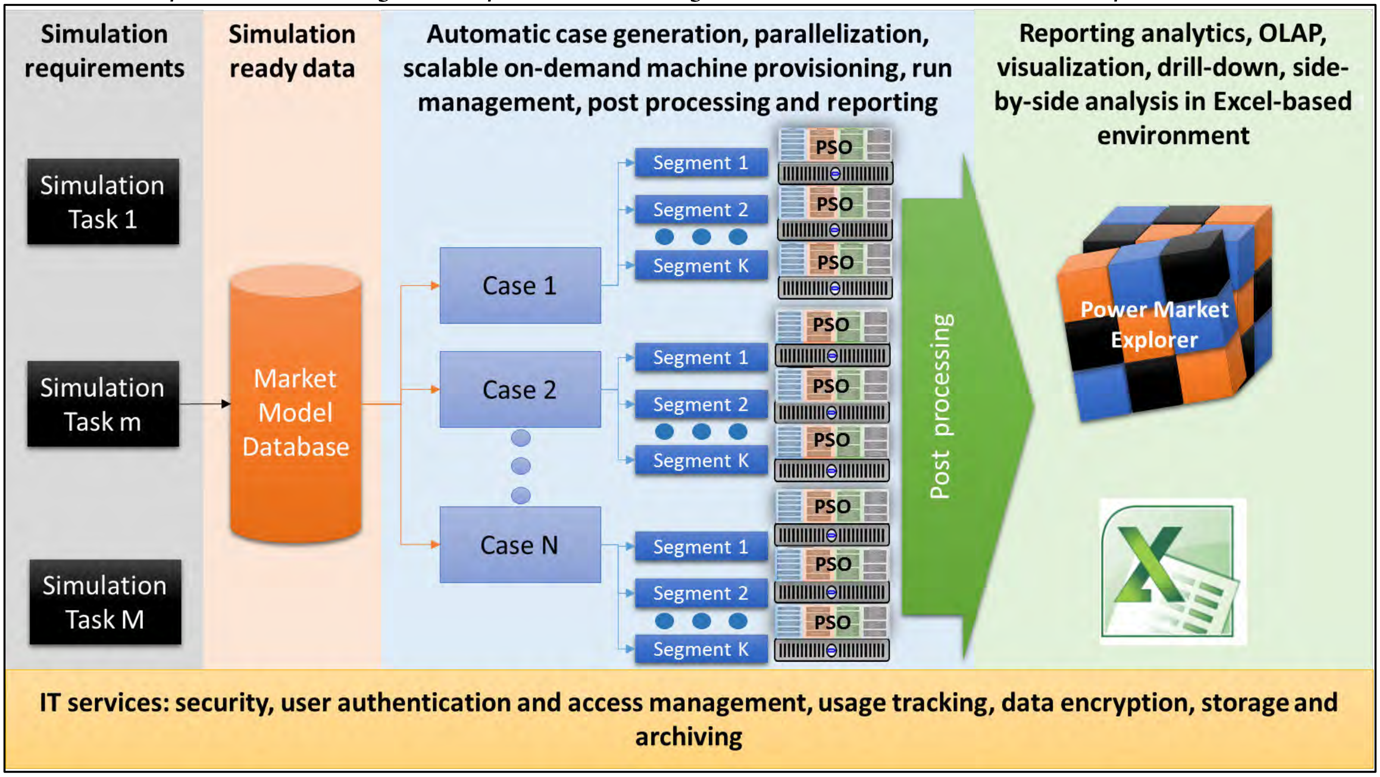

Figure A-2. Schematic of ENELYTIX Architecture

ENELYTIX automatically partitions each Case into Segments for parallel execution. Segments are queued and sent to servers dynamically procured on the cloud to be processed with PSO.

ENELYTIX collects output results, merges Segment related outputs corresponding to the same Case and sends both outputs and inputs to the Power Market Explorer (PME) Cube. PME is a multi-dimensional cube structure directly accessible from an Excel workbook on the user's desktop or laptop which provides self-service analytics for detailed exploration of output results in their entirety, side-by-side comparisons across cases, decision cycles, over time and numerous other dimensions. With PME, the user obtains instantaneous report generation via PivotTables and graphics via PivotCharts extracted directly from the PME cube. Although configurable, PME already comes with conveniently pre-calculated metrics including wholesale consumer payments, system-wide and regional adjusted production costs, emissions, curtailments, fuel use and detailed reports on assets' physical and financial performance.

ENELYTIX complies with high standards of data security properly protecting confidential and Critical Energy Infrastructure Information (CEII).

For additional information about ENELYTIX, visit www.enelytix.com.

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APPENDIX B: Fuel Price Forecast

B.1: Natural Gas Forecast Prices

Table Appendix B-1. Monthly Spot Gas Pries (2021 $/MMBtu)

Date	TGP Z 6	TGP Dracut	Algon Gates	Iroquois Z 2
1/1/2025	$5.92	$6.04	$5.92	$5.45
2/1/2025	$4.38	$4.45	$4.43	$3.92
3/1/2025	$3.25	$3.28	$3.17	$2.86
4/1/2025	$2.59	$2.64	$2.55	$2.41
5/1/2025	$2.57	$2.64	$2.49	$2.69
6/1/2025	$2.54	$2.60	$2.53	$2.67
7/1/2025	$2.56	$2.60	$2.56	$2.73
8/1/2025	$2.60	$2.63	$2.57	$2.85
9/1/2025	$2.57	$2.59	$2.55	$2.71
10/1/2025	$2.64	$2.67	$2.57	$2.67
11/1/2025	$3.11	$3.14	$2.98	$2.77
12/1/2025	$4.06	$4.15	$4.05	$3.31
1/1/2026	$5.63	$5.74	$5.63	$5.19
2/1/2026	$4.14	$4.21	$4.19	$3.70
3/1/2026	$3.29	$3.33	$3.21	$2.89
4/1/2026	$2.66	$2.71	$2.62	$2.48
5/1/2026	$2.62	$2.68	$2.53	$2.73
6/1/2026	$2.56	$2.63	$2.56	$2.69
7/1/2026	$2.63	$2.67	$2.63	$2.80
8/1/2026	$2.65	$2.68	$2.63	$2.91
9/1/2026	$2.62	$2.64	$2.60	$2.77
10/1/2026	$2.70	$2.72	$2.62	$2.72
11/1/2026	$3.20	$3.23	$3.05	$2.85
12/1/2026	$4.06	$4.15	$4.05	$3.31
1/1/2027	$5.68	$5.79	$5.68	$5.23
2/1/2027	$4.23	$4.30	$4.28	$3.79
3/1/2027	$3.29	$3.32	$3.20	$2.89
4/1/2027	$2.62	$2.66	$2.57	$2.44
5/1/2027	$2.56	$2.62	$2.47	$2.67
6/1/2027	$2.51	$2.57	$2.50	$2.63
7/1/2027	$2.57	$2.61	$2.57	$2.74
8/1/2027	$2.61	$2.64	$2.58	$2.87
9/1/2027	$2.57	$2.59	$2.55	$2.72
10/1/2027	$2.68	$2.70	$2.60	$2.70

REDACTED

11/1/2027	$3.20	$3.22	$3.05	$2.84
12/1/2027	$4.16	$4.26	$4.16	$3.39
1/1/2028	$5.87	$6.00	$5.88	$5.42
2/1/2028	$4.36	$4.43	$4.41	$3.90
3/1/2028	$3.40	$3.43	$3.31	$2.99
4/1/2028	$2.61	$2.65	$2.56	$2.43
5/1/2028	$2.54	$2.60	$2.46	$2.65
6/1/2028	$2.48	$2.55	$2.47	$2.61
7/1/2028	$2.56	$2.60	$2.56	$2.72
8/1/2028	$2.59	$2.62	$2.57	$2.85
9/1/2028	$2.56	$2.57	$2.53	$2.70
10/1/2028	$2.64	$2.67	$2.57	$2.66
11/1/2028	$3.22	$3.25	$3.07	$2.86
12/1/2028	$4.19	$4.29	$4.19	$3.42
1/1/2029	$5.91	$6.03	$5.91	$5.45
2/1/2029	$4.39	$4.46	$4.44	$3.93
3/1/2029	$3.35	$3.38	$3.26	$2.94
4/1/2029	$2.65	$2.70	$2.60	$2.47
5/1/2029	$2.54	$2.60	$2.46	$2.65
6/1/2029	$2.48	$2.54	$2.47	$2.61
7/1/2029	$2.56	$2.60	$2.55	$2.72
8/1/2029	$2.58	$2.61	$2.56	$2.83
9/1/2029	$2.54	$2.56	$2.52	$2.69
10/1/2029	$2.64	$2.67	$2.56	$2.66
11/1/2029	$3.21	$3.23	$3.06	$2.85
12/1/2029	$4.20	$4.29	$4.19	$3.42
1/1/2030	$6.01	$6.13	$6.02	$5.54
2/1/2030	$4.44	$4.51	$4.49	$3.97
3/1/2030	$3.36	$3.40	$3.27	$2.95
4/1/2030	$2.65	$2.70	$2.61	$2.47
5/1/2030	$2.55	$2.61	$2.46	$2.66
6/1/2030	$2.49	$2.55	$2.48	$2.61
7/1/2030	$2.56	$2.60	$2.56	$2.73
8/1/2030	$2.58	$2.61	$2.56	$2.84
9/1/2030	$2.55	$2.57	$2.53	$2.70
10/1/2030	$2.65	$2.67	$2.57	$2.67
11/1/2030	$3.34	$3.37	$3.19	$2.97
12/1/2030	$4.36	$4.46	$4.36	$3.56
1/1/2031	$6.02	$6.15	$6.03	$5.55
2/1/2031	$4.43	$4.51	$4.49	$3.97
3/1/2031	$3.36	$3.39	$3.27	$2.95
4/1/2031	$2.67	$2.72	$2.63	$2.49
5/1/2031	$2.57	$2.64	$2.49	$2.69
6/1/2031	$2.52	$2.58	$2.51	$2.64

REDACTED

7/1/2031	$2.59	$2.63	$2.59	$2.76
8/1/2031	$2.62	$2.65	$2.59	$2.88
9/1/2031	$2.58	$2.60	$2.56	$2.73
10/1/2031	$2.66	$2.69	$2.58	$2.68
11/1/2031	$3.32	$3.35	$3.17	$2.95
12/1/2031	$4.45	$4.55	$4.45	$3.63
1/1/2032	$6.18	$6.30	$6.18	$5.70
2/1/2032	$4.48	$4.55	$4.53	$4.01
3/1/2032	$3.52	$3.56	$3.43	$3.09
4/1/2032	$2.81	$2.86	$2.76	$2.62
5/1/2032	$2.69	$2.76	$2.61	$2.81
6/1/2032	$2.63	$2.69	$2.62	$2.76
7/1/2032	$2.70	$2.74	$2.69	$2.87
8/1/2032	$2.72	$2.76	$2.70	$3.00
9/1/2032	$2.69	$2.71	$2.67	$2.84
10/1/2032	$2.80	$2.83	$2.72	$2.82
11/1/2032	$3.40	$3.43	$3.25	$3.03
12/1/2032	$4.55	$4.66	$4.55	$3.71
1/1/2033	$6.46	$6.60	$6.47	$5.96
2/1/2033	$4.88	$4.96	$4.94	$4.37
3/1/2033	$3.53	$3.57	$3.44	$3.10
4/1/2033	$2.74	$2.79	$2.70	$2.55
5/1/2033	$2.61	$2.67	$2.53	$2.73
6/1/2033	$2.55	$2.61	$2.54	$2.68
7/1/2033	$2.62	$2.66	$2.62	$2.79
8/1/2033	$2.64	$2.67	$2.62	$2.90
9/1/2033	$2.61	$2.63	$2.59	$2.75
10/1/2033	$2.71	$2.74	$2.64	$2.74
11/1/2033	$3.34	$3.37	$3.19	$2.97
12/1/2033	$4.47	$4.57	$4.46	$3.64
1/1/2034	$6.68	$6.81	$6.68	$6.16
2/1/2034	$5.09	$5.18	$5.16	$4.56
3/1/2034	$3.61	$3.65	$3.52	$3.17
4/1/2034	$2.78	$2.83	$2.73	$2.59
5/1/2034	$2.72	$2.79	$2.63	$2.84
6/1/2034	$2.66	$2.73	$2.65	$2.79
7/1/2034	$2.71	$2.76	$2.71	$2.89
8/1/2034	$2.73	$2.77	$2.71	$3.01
9/1/2034	$2.72	$2.74	$2.70	$2.87
10/1/2034	$2.81	$2.84	$2.73	$2.83
11/1/2034	$3.54	$3.57	$3.38	$3.15
12/1/2034	$4.79	$4.90	$4.79	$3.91
1/1/2035	$6.54	$6.67	$6.55	$6.03
2/1/2035	$4.96	$5.04	$5.02	$4.44

REDACTED

3/1/2035	$3.55	$3.58	$3.46	$3.12
4/1/2035	$2.83	$2.88	$2.79	$2.64
5/1/2035	$2.73	$2.79	$2.64	$2.85
6/1/2035	$2.67	$2.73	$2.66	$2.80
7/1/2035	$2.70	$2.74	$2.70	$2.87
8/1/2035	$2.73	$2.77	$2.71	$3.00
9/1/2035	$2.73	$2.74	$2.70	$2.88
10/1/2035	$2.82	$2.85	$2.74	$2.84
11/1/2035	$3.65	$3.68	$3.49	$3.25
12/1/2035	$4.89	$5.01	$4.89	$3.99
1/1/2036	$6.69	$6.83	$6.70	$6.17
2/1/2036	$5.00	$5.08	$5.06	$4.48
3/1/2036	$3.60	$3.64	$3.51	$3.16
4/1/2036	$2.75	$2.80	$2.71	$2.57
5/1/2036	$2.67	$2.74	$2.59	$2.79
6/1/2036	$2.70	$2.77	$2.69	$2.83
7/1/2036	$2.70	$2.74	$2.70	$2.87
8/1/2036	$2.68	$2.71	$2.65	$2.94
9/1/2036	$2.76	$2.78	$2.74	$2.92
10/1/2036	$2.80	$2.83	$2.72	$2.83
11/1/2036	$4.00	$4.03	$3.82	$3.56
12/1/2036	$5.18	$5.30	$5.18	$4.22
1/1/2037	$6.96	$7.11	$6.97	$6.42
2/1/2037	$5.32	$5.41	$5.38	$4.76
3/1/2037	$3.45	$3.49	$3.36	$3.04
4/1/2037	$2.65	$2.69	$2.60	$2.46
5/1/2037	$2.61	$2.68	$2.53	$2.73
6/1/2037	$2.51	$2.58	$2.50	$2.64
7/1/2037	$2.54	$2.58	$2.54	$2.70
8/1/2037	$2.56	$2.59	$2.54	$2.82
9/1/2037	$2.56	$2.58	$2.54	$2.70
10/1/2037	$2.66	$2.68	$2.58	$2.68
11/1/2037	$3.67	$3.70	$3.51	$3.27
12/1/2037	$4.85	$4.96	$4.85	$3.96
1/1/2038	$6.77	$6.91	$6.78	$6.24
2/1/2038	$5.14	$5.23	$5.21	$4.60
3/1/2038	$3.43	$3.46	$3.34	$3.01
4/1/2038	$2.66	$2.70	$2.61	$2.48
5/1/2038	$2.61	$2.68	$2.53	$2.73
6/1/2038	$2.52	$2.58	$2.51	$2.65
7/1/2038	$2.56	$2.59	$2.55	$2.72
8/1/2038	$2.58	$2.61	$2.56	$2.84
9/1/2038	$2.56	$2.58	$2.54	$2.71
10/1/2038	$2.64	$2.67	$2.56	$2.66

REDACTED

11/1/2038	$4.18	$4.21	$3.99	$3.72
12/1/2038	$5.37	$5.49	$5.36	$4.37
1/1/2039	$6.72	$6.86	$6.73	$6.19
2/1/2039	$5.15	$5.23	$5.21	$4.61
3/1/2039	$3.42	$3.46	$3.33	$3.01
4/1/2039	$2.69	$2.74	$2.65	$2.51
5/1/2039	$2.62	$2.68	$2.53	$2.73
6/1/2039	$2.54	$2.60	$2.53	$2.66
7/1/2039	$2.55	$2.58	$2.54	$2.71
8/1/2039	$2.59	$2.62	$2.57	$2.85
9/1/2039	$2.60	$2.62	$2.58	$2.75
10/1/2039	$2.68	$2.70	$2.60	$2.70
11/1/2039	$3.98	$4.02	$3.81	$3.55
12/1/2039	$5.18	$5.30	$5.18	$4.22
1/1/2040	$6.85	$6.99	$6.85	$6.31
2/1/2040	$5.20	$5.28	$5.26	$4.65
3/1/2040	$3.49	$3.52	$3.40	$3.07
4/1/2040	$2.71	$2.76	$2.67	$2.53
5/1/2040	$2.69	$2.76	$2.60	$2.81
6/1/2040	$2.66	$2.72	$2.65	$2.79
7/1/2040	$2.67	$2.71	$2.66	$2.84
8/1/2040	$2.66	$2.69	$2.64	$2.93
9/1/2040	$2.68	$2.70	$2.65	$2.83
10/1/2040	$2.74	$2.76	$2.66	$2.76
11/1/2040	$4.16	$4.20	$3.97	$3.70
12/1/2040	$5.13	$5.24	$5.12	$4.18
1/1/2041	$6.37	$6.50	$6.38	$5.87
2/1/2041	$5.18	$5.27	$5.25	$4.64
3/1/2041	$3.51	$3.54	$3.42	$3.08
4/1/2041	$2.76	$2.81	$2.71	$2.57
5/1/2041	$2.79	$2.86	$2.70	$2.92
6/1/2041	$2.72	$2.79	$2.71	$2.86
7/1/2041	$2.69	$2.73	$2.69	$2.87
8/1/2041	$2.68	$2.71	$2.66	$2.95
9/1/2041	$2.73	$2.75	$2.71	$2.88
10/1/2041	$2.80	$2.83	$2.72	$2.83
11/1/2041	$4.28	$4.32	$4.09	$3.81
12/1/2041	$5.27	$5.39	$5.27	$4.30
1/1/2042	$6.29	$6.42	$6.30	$5.80
2/1/2042	$5.17	$5.26	$5.23	$4.63
3/1/2042	$3.41	$3.44	$3.32	$3.00
4/1/2042	$2.81	$2.86	$2.76	$2.61
5/1/2042	$2.74	$2.81	$2.65	$2.86
6/1/2042	$2.71	$2.78	$2.70	$2.84

REDACTED

7/1/2042	$2.67	$2.71	$2.67	$2.84
8/1/2042	$2.70	$2.73	$2.68	$2.97
9/1/2042	$2.70	$2.72	$2.68	$2.85
10/1/2042	$2.74	$2.77	$2.66	$2.77
11/1/2042	$4.21	$4.24	$4.02	$3.74
12/1/2042	$5.31	$5.43	$5.31	$4.33
1/1/2043	$6.18	$6.31	$6.19	$5.70
2/1/2043	$5.19	$5.27	$5.25	$4.64
3/1/2043	$3.31	$3.35	$3.23	$2.91
4/1/2043	$2.68	$2.73	$2.64	$2.50
5/1/2043	$2.71	$2.78	$2.63	$2.83
6/1/2043	$2.65	$2.71	$2.64	$2.78
7/1/2043	$2.65	$2.69	$2.65	$2.82
8/1/2043	$2.64	$2.67	$2.62	$2.91
9/1/2043	$2.64	$2.66	$2.62	$2.79
10/1/2043	$2.70	$2.73	$2.63	$2.72
11/1/2043	$4.11	$4.14	$3.93	$3.66
12/1/2043	$5.21	$5.33	$5.20	$4.24
1/1/2044	$6.34	$6.47	$6.34	$5.84
2/1/2044	$5.40	$5.49	$5.47	$4.83
3/1/2044	$3.33	$3.37	$3.25	$2.93
4/1/2044	$2.74	$2.79	$2.69	$2.55
5/1/2044	$2.71	$2.78	$2.63	$2.83
6/1/2044	$2.65	$2.71	$2.64	$2.78
7/1/2044	$2.69	$2.74	$2.69	$2.87
8/1/2044	$2.69	$2.72	$2.66	$2.95
9/1/2044	$2.64	$2.66	$2.62	$2.79
10/1/2044	$2.70	$2.73	$2.63	$2.73
11/1/2044	$4.19	$4.23	$4.00	$3.73
12/1/2044	$5.26	$5.38	$5.26	$4.29
1/1/2045	$6.37	$6.50	$6.37	$5.87
2/1/2045	$5.25	$5.34	$5.32	$4.70
3/1/2045	$3.34	$3.38	$3.25	$2.94
4/1/2045	$2.76	$2.81	$2.71	$2.57
5/1/2045	$2.78	$2.85	$2.69	$2.90
6/1/2045	$2.68	$2.74	$2.67	$2.81
7/1/2045	$2.72	$2.76	$2.72	$2.89
8/1/2045	$2.71	$2.74	$2.69	$2.98
9/1/2045	$2.70	$2.72	$2.68	$2.86
10/1/2045	$2.77	$2.79	$2.69	$2.79
11/1/2045	$4.20	$4.23	$4.01	$3.74
12/1/2045	$5.25	$5.37	$5.25	$4.28
1/1/2046	$6.33	$6.46	$6.33	$5.83
2/1/2046	$5.31	$5.40	$5.37	$4.75

REDACTED

3/1/2046	$3.34	$3.37	$3.25	$2.94
4/1/2046	$2.74	$2.79	$2.69	$2.55
5/1/2046	$2.80	$2.87	$2.71	$2.93
6/1/2046	$2.73	$2.80	$2.72	$2.87
7/1/2046	$2.70	$2.74	$2.70	$2.87
8/1/2046	$2.74	$2.77	$2.72	$3.01
9/1/2046	$2.68	$2.70	$2.66	$2.84
10/1/2046	$2.80	$2.82	$2.72	$2.82
11/1/2046	$4.25	$4.29	$4.06	$3.78
12/1/2046	$5.26	$5.38	$5.25	$4.29
1/1/2047	$6.34	$6.48	$6.35	$5.85
2/1/2047	$5.25	$5.34	$5.31	$4.70
3/1/2047	$3.36	$3.39	$3.27	$2.95
4/1/2047	$2.76	$2.81	$2.71	$2.57
5/1/2047	$2.73	$2.80	$2.64	$2.85
6/1/2047	$2.67	$2.73	$2.66	$2.80
7/1/2047	$2.66	$2.71	$2.66	$2.83
8/1/2047	$2.65	$2.69	$2.63	$2.92
9/1/2047	$2.64	$2.66	$2.62	$2.79
10/1/2047	$2.71	$2.74	$2.63	$2.73
11/1/2047	$4.26	$4.30	$4.07	$3.79
12/1/2047	$5.21	$5.32	$5.20	$4.24
1/1/2048	$6.39	$6.52	$6.40	$5.89
2/1/2048	$5.39	$5.48	$5.45	$4.83
3/1/2048	$3.38	$3.42	$3.29	$2.97
4/1/2048	$2.83	$2.88	$2.78	$2.64
5/1/2048	$2.80	$2.87	$2.71	$2.92
6/1/2048	$2.76	$2.83	$2.75	$2.90
7/1/2048	$2.77	$2.81	$2.77	$2.95
8/1/2048	$2.72	$2.75	$2.70	$2.99
9/1/2048	$2.75	$2.77	$2.73	$2.90
10/1/2048	$2.77	$2.80	$2.69	$2.79
11/1/2048	$4.39	$4.43	$4.19	$3.91
12/1/2048	$5.39	$5.51	$5.38	$4.39
1/1/2049	$6.52	$6.65	$6.53	$6.01
2/1/2049	$5.33	$5.41	$5.39	$4.77
3/1/2049	$3.45	$3.48	$3.36	$3.03
4/1/2049	$2.81	$2.86	$2.77	$2.62
5/1/2049	$2.86	$2.93	$2.77	$2.98
6/1/2049	$2.79	$2.86	$2.78	$2.93
7/1/2049	$2.79	$2.84	$2.79	$2.97
8/1/2049	$2.75	$2.78	$2.72	$3.02
9/1/2049	$2.77	$2.79	$2.75	$2.93
10/1/2049	$2.84	$2.87	$2.76	$2.86

REDACTED

11/1/2049	$4.44	$4.48	$4.24	$3.95
12/1/2049	$5.40	$5.53	$5.40	$4.40
1/1/2050	$6.50	$6.63	$6.51	$5.99
2/1/2050	$5.41	$5.50	$5.47	$4.84
3/1/2050	$3.43	$3.47	$3.34	$3.02
4/1/2050	$2.79	$2.84	$2.75	$2.60
5/1/2050	$2.83	$2.90	$2.74	$2.95
6/1/2050	$2.73	$2.79	$2.71	$2.86
7/1/2050	$2.76	$2.81	$2.76	$2.94
8/1/2050	$2.72	$2.75	$2.69	$2.99
9/1/2050	$2.74	$2.76	$2.72	$2.89
10/1/2050	$2.77	$2.80	$2.69	$2.79
11/1/2050	$4.40	$4.43	$4.20	$3.91
12/1/2050	$5.44	$5.56	$5.43	$4.43

B.2: Fuel Oil Prices Projection

Table Appendix B-2. Fuel Oil Prices Projection 2025-2050

Year	Distillate Oil Price (2021 $/MMBtu)	Residual Oil Price (2021 $/MMBtu)
2025	$15.89	$10.00
2026	$15.90	$10.01
2027	$16.32	$10.27
2028	$16.50	$10.39
2029	$16.98	$10.69
2030	$17.41	$10.96
2031	$17.71	$11.15
2032	$17.98	$11.32
2033	$18.20	$11.46
2034	$18.23	$11.48
2035	$18.20	$11.46
2036	$17.98	$11.32
2037	$18.00	$11.33
2038	$18.04	$11.35
2039	$17.82	$11.22
2040	$17.61	$11.09
2041	$17.39	$10.95
2042	$17.18	$10.81
2043	$17.02	$10.71
2044	$16.90	$10.64
2045	$16.83	$10.60
2046	$16.75	$10.55
2047	$16.48	$10.37

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Year	Distillate Oil Price (2021 $/MMBtu)	Residual Oil Price (2021 $/MMBtu)
2048	$15.98	$10.06
2049	$15.56	$9.79
2050	$15.32	$9.64

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F.2: New York Document

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Draft Report

Base Case for Evaluation of 83C Part III Proposals

Input and Modeling Assumptions

New York

Prepared for: **Eversource Energy, National Grid, Unitil**

Tabors Caramanis Rudkevich

March 15th, 2022

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DISCLAIMER

Tabors Caramanis Rudkevich, INC (TCR) has been contracted by the Massachusetts Electric Distribution Companies (EDCs), Eversource, National Grid and Unitil to provide the quantitative analyses that will allow the EDCs to evaluate the proposals that they receive in response to the 83C III RFPs. The information provided herein is solely for the purpose of development of a Base Case against which the proposed projects may be compared. Any other use of the materials without the explicit permission of TCR is strictly prohibited.

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CHAPTER 1:
Model Overview and Footprint

This document describes the modeling and input assumptions that the TCR team proposes for the New York power system (NYISO) model against which the Massachusetts electric distribution companies ("EDCs") will measure the incremental costs and benefits of each Proposal received in response to the 83C III RFP. In this document, TCR refers to that model as the "Base Case".

The complementary document "Base Case Evaluation of 83C III Proposals – Input and Modeling Assumptions New England" describes all 83C III Base Case modeling and input assumptions that are common to both New York and New England, as well as those that are specific to New England.

1.1: Base Case Design

For NYISO, TCR will first model capacity expansion to determine a schedule of optimal unit retirements and additions to meet future capacity requirements and minimize power system cost. Then, TCR will model the Energy and Ancillary Services (E&AS) market to simulate day-ahead and real-time economic transactions between ISO-NE and NYISO. To that end, TCR will use ENELYTIX's production costing capability to simulate the operation of the two neighboring markets – ISO-NE and NYISO. The New England assumptions document describes the ENELYTIX modeling environment for both capacity expansion and E&AS market simulation.

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CHAPTER 2: Transmission Topology

ENELYTIX® model organizes physical location of all network resources and loads using bus bar and node mapping. The NYISO transmission topology was modeled based on 2019 FERC 715 power flow fillings for summer peak 2024. Generators are mapped to bus bars/electrical nodes (eNodes). Bus bars are mapped to NYISO areas and to specific areas outside NYISO system. The mapping of load nodes to NYISO areas and external zones outside NYISO is used by ENELYTIX® to allocate area load forecasts to individual buses in proportion to bus specific loads in the power flow case.

In determining a representative list of transmission constraints to monitor, TCR included all major NYISO interfaces and critical contingencies. However, to make the Energy and Ancillary Services model run faster, all contingencies exclusively in the NYISO footprint were omitted. TCR developed limits for interfaces based on information provided in NYISO planning studies. Table 1 shows the Interface limits applied.

Table 1. Interface Limits

Constraint Name	Summer Max (MW)	Summer Min (MW)	Winter Max (MW)	Winter Min (MW)
CENTRAL-EAST	2,725	-9,999	3,100	-9,999
CONED-LIPA	800	-9,999	900	-9,999
DNWDIE-SOUTH-PI	4,000	-9,999	3,975	-9,999
DYSINGER-EAST	2,250	-9,999	2,250	-9,999
Moses-South	1,950	-9,999	1,175	-9,999
NE-NY	1,200	-1,200	1,200	-1,200
NNC	200	-200	200	-200
TOTAL-EAST	3,075	-9,999	4,075	-9,999
UPNY-CONED	6,750	-9,999	5,800	-9,999
VFT Interface	330	-300	330	-300

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CHAPTER 3: Interchange

In the Base Case, TCR models interchanges between NYISO and its neighboring systems (except for ISO-NE) as fixed flow schedules. Interchange with ISO-NE is economically dispatched as part of the E&AS model. For the fixed flow schedules, TCR uses 2019 historical hourly net interchange flow data obtained from NYISO for all interchanges flow schedules.

Table 2. Interchange Fixed Flow Schedule Summary

Interchange	Interfaces	Max Import (MW)	Max Export (MW)	Avg Import (MW)	Avg Export (MW)	Total Import (GWh)	Total Export (GWh)
HQ	Chateauguay	1,321	993	980	0.8	8,584	7
	Cedars	200	95	115	0.05	1,003	0.5
PJM	Hudson TP	660		150		1,314	
	Neptune	660		584		5,114	
	VFT	315	315	227	3	1,986	26
	Keystone	2,184	799	422	49	3,700	429
IESO		1,749	25	718	0.005	6,290	0.05

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CHAPTER 4: Load Forecast

4.1: Annual Gross Energy and Peak Forecast

TCR uses the policy scenario load forecast from Phase 1 report[1] of NYISO Climate Change Impact Study for this project. This load forecast provides hourly zonal load for 25 years from 2025 – 2050. The policy scenario assumed the State Clean Energy Standards' target for 2025 energy efficiency, solar and battery storage targets were met. In addition, the policy case also assumed the following:

- State average temperature trending 0.7 degrees Fahrenheit per decade
- Additional EE savings past the 2025 target
- 3,000 MW behind-the-meter solar capacity through 2050 in addition to the 6,000 MW target in 2025
- Implementation of state electrification programs with 25% of existing homes converting from fossil fuel to cold climate heat pumps by 2050
- 2,000 MW battery storage by 2050 in addition to the 3,000 MW target in 2025

TCR uses the net load as the base line load forecast for the Energy and Ancillary Service model. The net load incorporates the impact of energy efficiency savings, behind-the-meter PV impact, electric vehicle operations and heating electrification load. TCR will incorporate addition BMPV impact on this load if additional BMPV was built by the capacity expansion model.

Table 3 through Table 5 show the net energy and peak forecast.

1 New York ISO Climate Change Impact Study Phase 1: Long-Term Load Impact, Itron, December 2019

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Table 3. Projected Net Energy by Zone (GWh)

Year	A	B	C	D	E	F	G	H	I	J	K	*NYCA*
2025	12,965	8,854	13,449	3,708	6,527	10,163	8,236	2,351	5,352	46,939	18,633	*137,177*
2026	12,856	8,816	13,334	3,659	6,472	10,077	8,238	2,336	5,330	46,745	18,714	*136,577*
2027	12,776	8,797	13,251	3,618	6,432	10,015	8,260	2,325	5,318	46,641	18,849	*136,282*
2028	12,764	8,819	13,236	3,601	6,426	10,006	8,326	2,326	5,331	46,752	19,077	*136,664*
2029	12,689	8,796	13,158	3,560	6,388	9,948	8,346	2,316	5,318	46,642	19,233	*136,394*
2030	12,647	8,792	13,113	3,527	6,367	9,915	8,387	2,308	5,299	46,477	19,384	*136,216*
2031	12,670	8,830	13,136	3,512	6,379	9,934	8,469	2,311	5,305	46,532	19,635	*136,713*
2032	12,740	8,896	13,207	3,515	6,414	9,989	8,583	2,323	5,330	46,750	19,960	*137,707*
2033	12,735	8,911	13,201	3,492	6,411	9,986	8,645	2,322	5,328	46,733	20,220	*137,984*
2034	12,782	8,963	13,247	3,488	6,434	10,023	8,743	2,329	5,347	46,895	20,580	*138,831*
2035	12,835	9,017	13,301	3,485	6,461	10,065	8,848	2,339	5,372	47,112	21,004	*139,839*
2036	12,931	9,102	13,397	3,496	6,509	10,141	8,982	2,357	5,415	47,491	21,523	*141,344*
2037	12,948	9,131	13,414	3,481	6,518	10,156	9,063	2,361	5,430	47,628	21,993	*142,123*
2038	13,006	9,190	13,470	3,476	6,546	10,202	9,171	2,373	5,463	47,915	22,579	*143,391*
2039	13,075	9,257	13,540	3,475	6,581	10,257	9,292	2,386	5,501	48,244	23,120	*144,728*
2040	13,191	9,355	13,657	3,485	6,639	10,350	9,448	2,405	5,542	48,607	23,655	*146,334*
2041	13,235	9,403	13,699	3,473	6,660	10,385	9,545	2,413	5,561	48,772	24,059	*147,205*
2042	13,331	9,487	13,795	3,476	6,708	10,461	9,684	2,429	5,602	49,131	24,590	*148,694*
2043	13,435	9,575	13,899	3,482	6,760	10,544	9,828	2,448	5,647	49,525	25,142	*150,285*
2044	13,582	9,693	14,047	3,502	6,834	10,662	10,007	2,474	5,712	50,095	25,779	*152,387*
2045	13,661	9,765	14,126	3,496	6,873	10,724	10,135	2,489	5,750	50,435	26,343	*153,797*
2046	13,789	9,871	14,254	3,509	6,937	10,826	10,303	2,513	5,810	50,961	26,993	*155,766*
2047	13,922	9,980	14,389	3,522	7,004	10,932	10,477	2,537	5,874	51,518	27,673	*157,828*
2048	14,104	10,123	14,572	3,551	7,094	11,076	10,687	2,571	5,956	52,241	28,431	*160,406*
2049	14,213	10,215	14,682	3,556	7,149	11,163	10,842	2,592	6,010	52,714	29,092	*162,228*
2050	14,374	10,343	14,845	3,576	7,229	11,290	11,040	2,621	6,085	53,367	29,859	*164,629*

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Table 4. Projected Net Summer Peak by Zone (MW)

Year	A	B	C	D	E	F	G	H	I	J	K
2025	2,443	1,777	2,538	514	1,232	1,653	2,015	467	1,186	10,401	5,117
2026	2,118	1,768	2,510	490	1,070	1,634	2,024	465	1,185	10,391	5,155
2027	2,094	1,764	2,508	484	1,058	1,617	2,038	464	1,185	10,395	5,204
2028	2,227	1,763	2,512	499	1,124	1,606	2,056	464	1,171	10,273	5,264
2029	2,050	1,762	2,517	485	1,036	1,596	2,074	464	1,173	10,288	5,328
2030	2,449	1,760	2,521	481	1,234	1,587	2,092	463	1,171	10,270	5,384
2031	2,411	1,768	2,540	492	1,215	1,590	2,120	465	1,175	10,305	5,465
2032	2,066	1,775	2,562	470	1,043	1,592	2,150	468	1,179	10,343	5,554
2033	2,223	1,782	2,581	492	1,122	1,595	2,179	470	1,184	10,386	5,649
2034	2,037	1,794	2,606	466	1,029	1,601	2,212	473	1,191	10,442	5,757
2035	2,061	1,803	2,630	480	1,041	1,607	2,245	476	1,198	10,505	5,876
2036	2,509	1,816	2,655	485	1,263	1,616	2,279	479	1,206	10,578	6,006
2037	2,099	1,825	2,682	474	1,299	1,621	2,315	483	1,214	10,649	6,153
2038	2,102	1,836	2,707	474	1,312	1,627	2,349	486	1,223	10,725	6,310
2039	2,281	1,848	2,735	500	1,325	1,636	2,386	490	1,232	10,807	6,455
2040	2,089	1,861	2,765	471	1,340	1,646	2,425	494	1,240	10,872	6,592
2041	2,577	1,876	2,796	488	1,355	1,656	2,464	498	1,249	10,956	6,729
2042	2,545	1,893	2,830	504	1,281	1,670	2,508	503	1,260	11,053	6,879
2043	2,172	1,908	2,866	484	1,390	1,681	2,552	508	1,271	11,151	7,037
2044	2,185	1,926	2,902	486	1,408	1,696	2,598	513	1,285	11,267	7,198
2045	2,166	1,945	2,943	483	1,428	1,711	2,647	519	1,298	11,386	7,376
2046	2,202	1,966	2,984	489	1,448	1,728	2,697	525	1,313	11,519	7,556
2047	2,243	1,994	3,027	506	1,469	1,760	2,750	532	1,330	11,669	7,746
2048	2,250	2,010	3,072	526	1,491	1,766	2,804	538	1,346	11,805	7,936
2049	2,270	2,031	3,119	504	1,514	1,782	2,861	545	1,363	11,953	8,143
2050	2,296	2,056	3,168	536	1,538	1,803	2,919	553	1,381	12,113	8,353

Table 5. Projected Net Winter Peak by Zone (MW)

Year	A	B	C	D	E	F	G	H	I	J	K
2024-2025	2,371	1,499	2,504	558	1,202	1,843	1,537	409	822	7,205	3,267
2025-2026	2,356	1,496	2,485	555	1,193	1,832	1,539	407	817	7,169	3,292
2026-2027	2,374	1,513	2,503	556	1,203	1,846	1,563	410	827	7,251	3,361
2027-2028	2,390	1,527	2,519	559	1,210	1,859	1,587	413	832	7,297	3,433
2028-2029	2,401	1,535	2,531	561	1,216	1,868	1,607	415	833	7,304	3,504
2029-2030	2,419	1,550	2,549	562	1,225	1,882	1,630	417	836	7,332	3,578
2030-2031	2,447	1,572	2,578	566	1,239	1,904	1,660	422	842	7,384	3,676
2031-2032	2,457	1,585	2,586	568	1,244	1,913	1,681	423	842	7,388	3,762
2032-2033	2,489	1,610	2,618	573	1,260	1,937	1,715	429	855	7,500	3,875
2033-2034	2,518	1,631	2,649	579	1,275	1,960	1,748	433	858	7,527	3,997
2034-2035	2,542	1,648	2,674	583	1,287	1,979	1,777	437	866	7,597	4,122
2035-2036	2,579	1,676	2,712	589	1,305	2,008	1,814	443	877	7,690	4,269
2036-2037	2,588	1,690	2,720	559	1,310	2,016	1,836	446	879	7,711	4,418
2037-2038	2,626	1,719	2,759	597	1,329	2,046	1,875	453	895	7,852	4,611
2038-2039	2,659	1,744	2,793	602	1,345	2,071	1,914	458	906	7,948	4,777
2039-2040	2,697	1,771	2,833	608	1,364	2,101	1,955	464	911	7,992	4,932
2040-2041	2,727	1,793	2,863	571	1,379	2,124	1,989	469	921	8,082	5,066
2041-2042	2,767	1,823	2,904	619	1,400	2,156	2,030	476	932	8,178	5,226
2042-2043	2,785	1,843	2,922	623	1,409	2,171	2,060	480	937	8,220	5,377
2043-2044	2,835	1,880	2,973	630	1,434	2,210	2,110	488	956	8,388	5,558
2044-2045	2,877	1,910	3,017	637	1,455	2,243	2,157	495	966	8,470	5,749
2045-2046	2,915	1,937	3,056	644	1,474	2,273	2,199	502	979	8,591	5,924
2046-2047	2,964	1,973	3,106	652	1,499	2,311	2,248	510	995	8,730	6,120
2047-2048	3,013	2,009	3,157	659	1,523	2,350	2,298	519	1,011	8,864	6,311
2048-2049	3,052	2,043	3,195	666	1,543	2,381	2,343	526	1,027	9,004	6,521
2049-2050	3,103	2,080	3,248	675	1,568	2,421	2,398	535	1,044	9,154	6,738

4.2: Behind-the-Meter Photovoltaic Forecast

The policy case load forecast embedded in its net load the required 6,000 MW BMPV by 2025. The BMPV generation reflects climate change over the study period. Table 6 shows zonal distribution of BMPV in the climate impact study load forecast. Figure 1 below shows zonal PV capacity factor over the study period.

Table 6. BMPV Zonal Distribution in Climate Impact Study

Zone	Fraction
A	12.9%
B	4.0%
C	11.0%
D	1.3%
E	12.4%
F	15.2%
G	12.6%
H	1.1%
I	1.6%
J	12.3%
K	15.6%

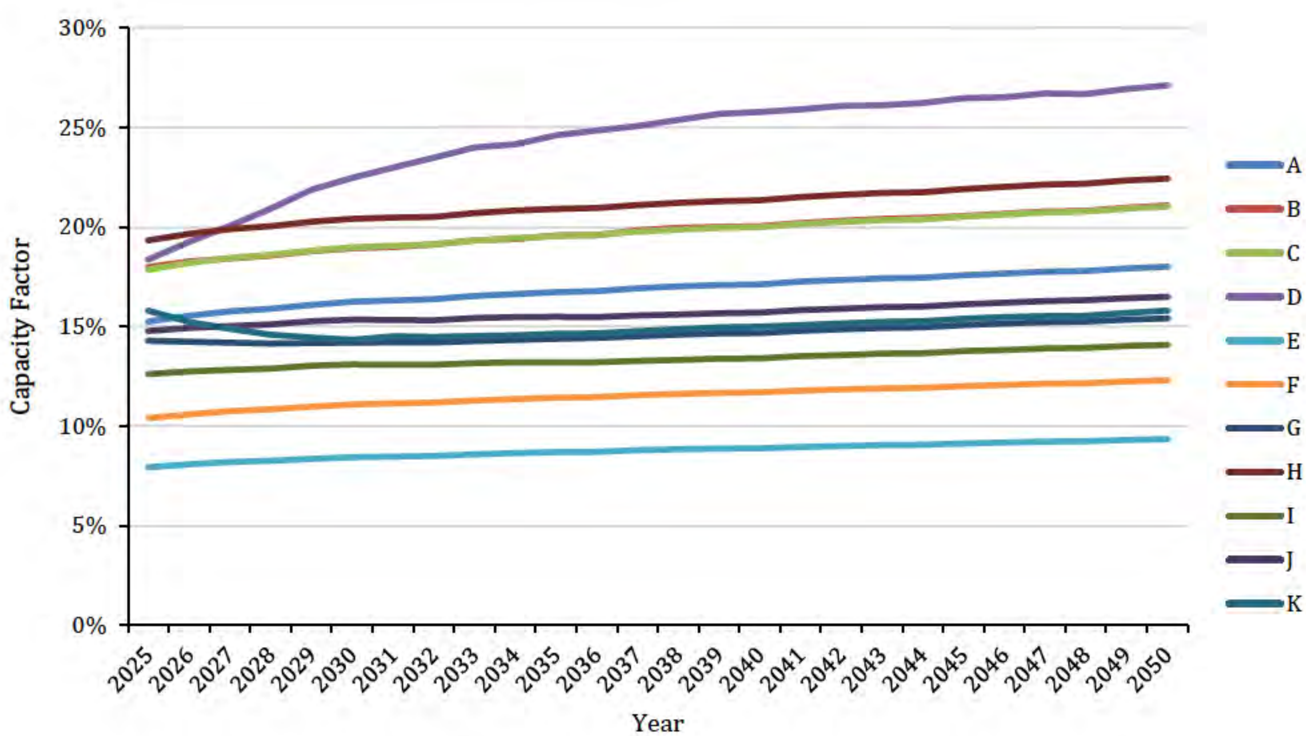

Figure 1. BMPV Capacity Factor

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4.3: Energy Efficiency Impact Forecast

The climate impact study load used in this model already incorporated the State's Energy Efficiency Saving target. The 26 TWh energy efficiency saving embedded in the load forecast exceeds the target established in the New York State Public Service Commission (PSC)'s Dec 13th, 2018 order[2], which mandated New York's Investor Own Utilities (IOU) to reduce their electricity sales by 3% by 2025. TCR will not be modeling additional EE saving in additional that is forecasted in the climate impact study.

4.4: Heating Electrification Load Forecast

The load forecast implemented a state electrification program with 25% of existing home conversion to heat pumps by 2050. Other end use electrification including water heating and cooking is also included in the forecast. TCR will not model additional electrification load in addition to what is forecasted in the load.

4.5: Electric Vehicles

The policy case load forecast includes incremental load due to increasing penetration of electric vehicles. A total of 5,488 GWh of load is attributed to electric vehicles in 2030. This load translates to more than 1 million[3] plug-in electric vehicles in New York and exceeds the state's goal of 800,000 electric vehicles by 2030. TCR will not model additional EV load in addition to what is forecasted in the policy case load.

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2 Order Adopting Accelerated Energy Efficiency Target, New York Public Service Commission, Dec 13th, 2018
3 This calculation is based on DOE's EV fact sheet, which assumes an average annal mileage of 11,824 miles and an average fuel economy of 0.32 kWh/mile. https://afdc.energy.gov/vehicles/electric_emissions_sources html

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CHAPTER 5:
Ancillary Service Requirements

Following NYISO's structure of ancillary services, TCR models four types of reserves: Regulation, 10 minute spinning (10MSR), 10 minute non-spinning (10MNSR) and 30 minute reserves (30MR). Reserves are cascading, meaning that excess higher quality reserves counted toward meeting lower quality reserve requirements. For example, excess 10MSR count toward 10MNSR requirements and both excess 10MSR and 10MNSR reserves count toward 30MR. Spinning reserves are based upon NERC requirements. In addition, NYISO has locational requirements for the reserves on Long Island and near Central East. Non-spinning reserves can be provided by GTs and Internal Combustion (IC) units.

Hydro units can provide Regulation, Ten-Minute Spinning Reserve, and Thirty-Minute Operating Reserve for up to 5%, 10%, and 30% of its dispatch range, respectively. PV, wind, nuclear, and storage cannot provide ancillary services.

Table 7 summarizes reserve requirements in NYISO. Regulation reserves vary on an hourly basis and are not presented here.

Table 7. New York ISO Reserve Requirements

Reserve Type	Area	Requirement (MW)
10MSR	NYISO	665
10MNSR	NYISO	665
30MR	NYISO	665
10MSR	ENY (Zones F-K)	330
10MNSR	ENY	870
10MNSR	K	120
30MR	K	270 Off-peak /420 On-peak

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CHAPTER 6: NYISO Capacity Requirement

6.1: Capacity Requirement and Reserve Margin

Four capacity pools were modeled for NYISO in the Base Case: NYCA (all NYISO), Zone J, Zone K, and Zones G-J. For each of these capacity pools a UCAP requirement was calculated. For the NYCA pool, the UCAP requirement is based on the New York State Reliability Council (NYSRC) 2021-22 Installed Reserve Margin (IRM)[4], and Summer 2021 derating factors[5]. For the other pools, the URM is based on the Locational Minimum Installed Capacity Requirements (LCRs) for the 2021-22 Capability Year, as well as 5-year derating factors.

$$NYCA\ UCAP\ Requirement = (1 + IRM) * (1 - derating\ factor)$$

$$Locational\ (Zone\ Pools)\ UCAP\ Requirement = LCR * (1 - derating\ factor)$$

Table 8 shows the UCAP requirement inputs and results for each of the capacity pools.

Table 8. UCAP Requirement Inputs and Result

	NYCA	J	K	G-J
IRM	20.7%			
Average Derating Factors (Summer 2021)	8.77%			
LCR		80.3%	102.9%	87.6%
5-Year Derating Factor		9.17%	9.24%	10.07%
UCAP Requirement	*1.101*	*0.729*	*0.934*	*0.788*

For each pool, the capacity requirement was calculated as:

$$Capacity\ Requirement = Peak\ Load * URM - Import\ Credits$$

Capacity requirements were calculated both summer and winter, using the season's respective peak load. Import credits were sourced from the NYISO Installed Capacity Manual.[6] The import credit values are summarized in Table 9 – an "x" underneath the pool name indicates that the import credit was applied to that pool.

4 Locational Minimum Installed Capacity Requirements Study. NYISO. 1/14/2021. https://www.nyiso.com/documents/20142/17462310/LCR2021-Report.pdf/9e390b73-99a7-0ee5-6466-bbd3f7e71af4
5 https://www.nyiso.com/documents/20142/3036383/4_Amt%20of%20Capacity%20Qualified%20to%20Offer.pdf/57f56a99-3293-d795-8584-21a70c495a5a
6 NYISO Manual 4: Installed Capacity Manual, 88-89. May 2021. https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338

Table 9. Import Credit Summary

Import Source	Import Credit (MW)	NYCA	J	K	G-J
Grandfathered (MW) and CY External CRIS (MW)					
Quebec via Chateauguay	1110	x			
PJM	38	x			
Unforced Capacity Deliverability Rights					
Cross Sound Cable	330	x		x	
Neptune Cable	660	x		x	
Linden VFT	315	x	x		x
Hudson	660	x	x		x

6.2: Contribution of Resources toward Capacity Requirement

TCR models thermal generation resources' available UCAP value as a percentage of their capacity ("capacity contribution factor") based on a fleet-wide Effective Forced Outage Rate (EFORd). For solar and wind, TCR used summer capacity contribution factors from the New York State Reliability Council (NYSRC) white paper "The Impacts of High Intermittent Renewable Resources."[7] Winter capacity contribution factors for solar and wind were based on an analysis of solar and wind capacity factors over the winter season using the generation shapes from this NYISO model. Table 10 shows summer capacity contribution factors for different unit types.

Table 10. Summer Capacity Contribution Factors by Unit Type

Unit Type	Capacity Contribution
Battery Storage	100%
Biomass -- Gas	92%
Biomass -- Solid	92%
Coal	92%
Oil/Gas Steam Turbine	92%
Combined Cycle (H-Class)	96%
Combustion Turbine Aero	91%
Hydro	96%
Internal Combustion	91%
Nuclear	92%
Pumped Storage Hydro	96%
Solar PV	29%
BTMPV	0%
Onshore Wind	16%
Offshore Wind	32%

7 https://www.nysrc.org/PDF/Reports/HR%20White%20Paper%20-%20Final%204-9-20.pdf

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CHAPTER 7: RES Requirements and CLCPA Compliance

This chapter describes the modeling assumptions representing renewable energy portfolio requirements and electricity sector GHG reduction targets.

7.1: The CES Order

The NYPSC's 2016 CES Order[8] provides for a Renewable Energy Standard (RES) and Clean Energy Standard (CES), which include both short-term and long-term requirements for the amount of electricity consumed in the state that is to be generated by renewable resources. In the short term, the CES Order required LSEs, with no exemptions, to retire renewable energy certificates (RECs) produced by "Tier 1" resources in quantities corresponding to specified percentages of their load for each year through 2021.[9] The order includes eligibility requirements for Tier 1 resources that include location,[10] technology, and fuel and require that the resources have commenced commercial operation no earlier than January 1, 2015.

The CES Order also requires that at least 50% of electricity consumed in the state in 2030 be produced by renewable resources ("50x30"), including Tier 1 resources and so-called baseline resources. Baseline resources are those renewable resources that came online prior to 2015, including those associated with imports.

7.2: The CLCPA

The CLCPA, issued in June 2019, considerably increased the renewable energy goals that had been the basis of the CES Order. It increased the 2030 requirement to 70% renewable ("70x30") and called for the electricity sector to reduce its GHG emissions by 100% by 2040. Additionally, it called for increased energy efficiency by 2030, which would have the effect of reducing the absolute amount of renewable energy needed to meet the 70x30 requirement.

The CLCPA objectives have not yet been proposed as specific plans or requirements, so some interpretation is required to translate the requirements into modeling assumptions for each year of the analysis.

7.3: Total and Tier 1 Renewable Energy Requirements

To determine a total renewable energy (TRE) requirement for years leading up to 2030, we interpolate linearly between a 2021 requirement and the 70x30 target. The assumed 2021 TRE requirement of 30.85% is calculated by adding the 2018-2021 incremental Tier 1 requirement, 4.05%, to the 2018 reported actual renewable energy percentage of load (26.8%). After 2030, the total renewable energy

8 NYPSC, Order Adopting a Clean Energy Standard, Case No. 15-E-0302, August 1, 2016.

9 The annual percentages for years through 2021 have since been updated, most recently in the Clean Energy Standard Final Phase 3 Implementation Plan, filed by NYSERDA staff and NYPSC staff in Case No. 15-E-0302, January 11, 2019.

10 Resources must be located in the NYCA or an adjacent control area; for resources in adjacent control areas, there must either be documentation of a contract path between the generator and the in-state purchaser that includes transmission rights, or transmission of an amount of spot market energy, corresponding to the plant's generation, from the source control area to the NYCA in each hour.

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requirement is assumed to remain at 70%, with the 2040 GHG target driving future renewables growth. The annual TRE requirement is presented in Table 11.

Because all the increase in the TRE requirement must be made up by new Tier 1 resources, the total renewable energy requirement can be translated into a Tier 1 requirement for each year as a percentage of load:

Tier 1 Requirement = TRE Requirement – (baseline renewable energy / load)

where the baseline renewable energy is the sum of energy generated by in-state baseline resources (which will vary by year) and a fixed estimate of baseline renewable energy imports, taken as the reported value for 2018, approximately 12,862 GWh, minus estimated exports from the NYPA Moses Niagara and St. Lawrence fleets, a net of 10,597 GWh. The load to which the requirement is applied is net load plus Behind-the-Meter load, as discussed in the following subsection.

Table 11. Total Renewable Energy Requirement

Year	Requirement (% of load)
2021	30.9%
2022	35.2%
2023	39.5%
2024	43.9%
2025	48.3%
2026	52.6%
2027	57.0%
2028	61.3%
2029	65.7%
2030	70.0%
…	…
2050	70.0%

7.4: Compliance Treatment of Behind-the-Meter Generation

The questions of whether and how the environmental attributes associated with Behind-the-Meter (BTM) generation should count toward compliance requirements or targets, and whether BTM load should be included in RES- and/or CES-obligated load are discussed in the CES Order and the Staff White Paper on the CES.[11] Generally, the CES states that BTM resources whose RECs are not retired to meet an LSE's obligation (i.e., in the LSE's NYGATS account) are considered to be retained for voluntary additionality purposes and cannot count toward compliance with the RES (e.g., Tier 1).

The Value of Distributed Energy Resources (VDER) Order[12] subsequently clarified that while RECs retained for voluntary additionality purposes will not be counted towards LSE Tier 1 obligations, they

11 NY Dept. of Public Service, Staff White Paper on Clean Energy Standard, Case 15-E-0302, January 25, 2016.

12 Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters, Case No. 15-E-0751, March 9, 2017.

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"will be counted towards the State's 50% by 2030 renewable energy goal, because that aggressive target is based on the contributions of all actors."[13]

With regard to load calculations, the CES Order and the Staff White Paper indicate that the load used to determine a particular obligation should be adjusted to include (add) BTM load if the associated environmental attributes are being retired for compliance with that obligation, whereas the load used to determine an obligation should not be adjusted to include (add) BTM load if the associated attributes are being retained for voluntary additionality.

Given the modeling complexity of treating attributes differently depending on whether they are retired for voluntary or compliance purposes—as well as the lack of substantial basis to project the fractions of BTM resources whose RECs are used for each purpose, we will make the simplifying assumptions that RECs of all BTM resources will count toward the total renewable energy requirement, and that the RECs of all Tier 1 eligible BTM resources (i.e., which became operational after 2014) will count toward the Tier 1 requirement.

7.5: GHG Cap

We represent compliance with the 2040 CLCPA electricity sector target of complete GHG reduction by assuming that emissions for in-state and imported electricity decline linearly from their 2016 level to zero in 2040.[14] We only enforce that constraint, however, beginning in 2031. The assumed annual requirements are listed in Table 12 below. Because by 2040, imports will not be expected to be completely GHG-free, and some in-state thermal generation may still be needed for operating reserves, for modeling purposes we interpret the complete reduction of electricity-sector GHG emissions to mean that the energy needed to supply 100% of the load is either renewable (in-state or imported) or nuclear.

Table 12. Assumed GHG Limits

Year	Assumed Cap, MMTCO$_2$e
2031	11.8
2032	10.5
2033	9.2
2034	7.9
2035	6.6
2036	5.3
2037	3.9
2038	2.6
2039	1.3
2040 and beyond	0

13 NYSERDA, Value of Distributed Energy Resources (VDER): Frequently Asked Questions, Updated 6/23/2017.

14 The 2016 electricity sector GHG emissions level, 31.54 MMTCO2e, can be found in Table S-2 of NYSERDA's New York State Greenhouse Gas Inventory: 1990–2016, Final Report, July 2019.

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7.6: NYSERDA Tier 4 Resource

The New York Public Service Commissions October 15, 2020 Order[15] established a new Tier 4 within the New York CES. This tier increases the penetration of renewable energy into New York City (NYISO Zone J) to meet the statewide clean energy policy targets. To account for such future clean energy procurement, TCR reviewed the NYSERDA Power Grid Study[16] and used similar assumptions to account for a proxy future transmission project that would deliver zero emission clean energy. This proxy project is assumed to provide 1,250 MW of firm capacity and offers up to 10,0000 GWh of dispatchable energy at an assumed capacity factor of 91% by 2025.

TCR will assume all ancillary service provided by thermal generating units, if such generators remain in the fleet, to be provided by Renewable Natural Gas generating units.

15 https://www nyserda ny.gov/-/media/Files/Programs/Clean-Energy-Standard/2020/October-15-Order-Adopting-Modifications-to-the-Clean-Energy-Standard.pdf
16 https://www nyserda ny.gov/About/Publications/New-York-Power-Grid-Study

CHAPTER 8:
Generating Capacity

TCR obtains operating generation assets list from NYISO's 2021 Load & Capacity Data Report (Gold Book). Based on this list of operating assets, TCR includes scheduled generation additions and retirements from the Gold Book as well as information on clean energy procurements under contract from NYSERDA to capture the changes in NYISO's generation mix during the 2025-2050 simulation period for this project.

After introducing scheduled capacity additions and retirements, future additions and retirements will be determined by ENELYTIX's capacity expansion model based on capacity requirement, TRE requirements, and emission regulations.

8.1: Scheduled generator additions

TCR obtained scheduled capacity additions using the NYISO interconnection queue and S&P Global' s generation asset database. TCR obtains a listing of projects that are currently under construction from both sources and then cross references them to obtain a complete collection of scheduled generation additions and upgrades. Table 13 summarizes TCR's scheduled generator additions from the Gold Book in the model.

Table 13. Scheduled Generation Additions and Update

Unit Name	Energy Area	Unit Type	Summer Capacity (MW)	Online Date
Calverton Solar Energy Center	K	PV	22.9	12/1/2021
Number Three Wind Energy	E	Wind	105.8	9/1/2022
Excelsior Energy Center	A	PV	280	11/1/2022
North Light Energy Center	C	PV	80	11/1/2022
High River Solar	F	PV	90	11/1/2022
East Point Solar	F	PV	50	11/1/2022
Deepwater Offshore Wind WT 1	K	Offshore Wind	136	12/1/2022
South Fork Wind Farm II	K	Wind	40	12/1/2022
Bear Ridge Solar	A	PV	100	12/1/2022
Canisteo Wind	C	Wind	290.7	12/1/2022
Watkins Glen Solar	C	PV	50	12/1/2022
Highview Solar	C	PV	20	12/1/2022
High Bridge Wind	E	Wind	100.8	12/1/2022
Mohawk Solar	F	PV	90.5	12/1/2022
Flint Mine Solar	G	PV	100	12/1/2022
KCE NY 2	G	ES	200	12/1/2022
Riverhead Expansion	K	PV	36	12/1/2022
Berrians East Replacement	J	IC/GT	431	6/1/2023
Baron Winds	C	Wind	238.4	7/1/2023
Homer Solar Energy Center	C	PV	90	9/1/2023
Danskammer Energy Center	G	CC	595.5	10/1/2023

Unit Name	Energy Area	Unit Type	Summer Capacity (MW)	Online Date
North Side Solar	D	PV	180	11/1/2023
Columbia County 1	F	PV	60	12/1/2023

In addition to those generators the Base Case also includes clean energy additions that are procured under contract by NYSERDA, which are listed in Table 14.

Table 14. NYSERDA Generation Additions and Updates

Unit Name	Energy Area	Unit Type	Summer Capacity (MW)	Online Date
Tayandenega Solar PV 1	F	PV	20	6/1/2021
Ball Hill Windpark WT 1	A	Wind	100.1	12/1/2021
Regan Solar PV 1	E	PV	20	12/1/2021
Coeymans Solar Farm PV 2	F	PV	40	1/1/2022
Coeymans Solar	F	PV	40	1/1/2022
Greene County Energy Properties	G	PV	19.9	1/1/2022
Little Pond Solar	G	PV	20	1/1/2022
Rock District Solar	F	PV	20	1/1/2022
Sky High Solar	C	PV	20	1/1/2022
Bakerstand Solar 1	A	PV	20	1/1/2022
Hannacroix Solar Facility	G	PV	5	1/1/2022
Horseshoe Solar	B	PV	180	1/1/2022
SED Clay Solar	C	PV	20	1/1/2022
SED Dog Corners Solar	C	PV	20	1/1/2022
SED Hills Solar	E	PV	20	1/1/2022
SED Manchester Solar	C	PV	20	1/1/2022
SED Skyline Solar	E	PV	20	1/1/2022
SED Watkins Road Solar I	E	PV	20	1/1/2022
Silver Lake Solar Project	A	PV	25	1/1/2022
Trelina Solar Energy Center	C	PV	80	1/1/2022
ELP Ticonderoga Solar	F	PV	20	1/1/2022
Delight Farm	C	PV	16.8	1/1/2022
SunEast Flat Creek Solar	F	PV	200	1/1/2022
SunEast Flat Stone Solar	E	PV	20	1/1/2022
SunEast Kingbird Solar	A	PV	20	1/1/2022
Sky High Solar PV 1	C	PV	20	7/1/2022
Eight Point Wind WT 1	C	Wind	101.8	9/1/2022
Greene County	G	PV	50	1/1/2023
Heritage Wind LLC	B	Wind	147	1/1/2023
Morris Ridge Solar	C	PV	170	1/1/2023
Bald Mountain Solar	F	PV	20	1/1/2023
Garnet Energy Center Storage 1	B	PV	200	1/1/2023
Greens Corners Solar	E	PV	120	1/1/2023
Prattsburgh Wind Farm	C	Wind	145	1/1/2023
Sandy Creek Solar	E	PV	20	1/1/2023

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Unit Name	Energy Area	Unit Type	Summer Capacity (MW)	Online Date
South Ripley Solar and Storage	A	PV	270	1/1/2023
SunEast Fairway Solar	E	PV	20	1/1/2023
SunEast Flat Hill Solar	E	PV	20	1/1/2023
SunEast Grassy Knoll Solar	E	PV	20	1/1/2023
SunEast Highview Solar	A	PV	20	1/1/2023
SunEast Hilltop Solar	F	PV	20	1/1/2023
SunEast Limestone Solar	F	PV	20	1/1/2023
SunEast Tabletop Solar	F	PV	80	1/1/2023
SunEast Valley Solar	C	PV	20	1/1/2023
West River Solar	F	PV	20	1/1/2023
Dolan Solar	F	PV	20	1/1/2023
Hawthorn Solar	F	PV	20	1/1/2023
Moraine Solar Energy Center	C	PV	93.6	1/1/2023
Somers Solar	F	PV	20	1/1/2023
SunEast Augustus Solar	E	PV	20	1/1/2023
SunEast Transit Solar	A	PV	20	1/1/2023
Tracy Solar Energy Center	E	PV	119	1/1/2023
Empire Wind	J	Offshore Wind	816	1/1/2024
Sunrise Wind	K	Offshore Wind	880	1/1/2024
Martin Rd Solar	A	PV	20	1/1/2024
Alabama Solar Park	B	PV	130	1/1/2024
Clear View Solar	C	PV	20	1/1/2024
Hatchery Solar	C	PV	20	1/1/2024
Highbanks Solar	C	PV	20	1/1/2024
Mill Point Solar	E	PV	250	1/1/2024
Milliken Solar	C	PV	200	1/1/2024
Orleans Solar	B	PV	200	1/1/2024
Cider Solar Farm	A	PV	500	1/1/2025
Rutland Center Solar 1	E	PV	110.2	1/1/2025
Empire Wind 2	J	Offshore Wind	1260	1/1/2026
Beacon Wind	E	Offshore Wind	1230	1/1/2028

8.2: Scheduled retirements

TCR obtained approved NYISO generation retirements from 2021 Gold Book. Table 15 summarizes approved retirement.

Table 15. NYISO Approved Retirements

Unit Name	Energy Area	Unit Type	Summer Capacity (MW)	Retire Date
Danskammer 1	G	ST	69.5	3/1/2023
Danskammer 2	G	ST	64.2	3/1/2023
Danskammer 3	G	ST	138.4	3/1/2023
Danskammer 4	G	ST	225.3	3/1/2023

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Unit Name	Energy Area	Unit Type	Summer Capacity (MW)	Retire Date
Astoria GT 2-1	J	IC/GT	35.1	5/1/2023
Astoria GT 2-2	J	IC/GT	34.6	5/1/2023
Astoria GT 2-3	J	IC/GT	35.8	5/1/2023
Astoria GT 2-4	J	IC/GT	34.9	5/1/2023
Astoria GT 3-1	J	IC/GT	34.8	5/1/2023
Astoria GT 3-2	J	IC/GT	35.7	5/1/2023
Astoria GT 3-3	J	IC/GT	35.6	5/1/2023
Astoria GT 3-4	J	IC/GT	36.2	5/1/2023
Astoria GT 4-1	J	IC/GT	32.9	5/1/2023
Astoria GT 4-2	J	IC/GT	33.6	5/1/2023
Astoria GT 4-3	J	IC/GT	33.7	5/1/2023
Astoria GT 4-4	J	IC/GT	33.5	5/1/2023
Coxsackie GT	G	IC/GT	19.3	5/1/2023
Gowanus 1-1	J	IC/GT	18.6	5/1/2023
Gowanus 1-2	J	IC/GT	19.5	5/1/2023
Gowanus 1-3	J	IC/GT	17.9	5/1/2023
Gowanus 1-4	J	IC/GT	16.4	5/1/2023
Gowanus 1-5	J	IC/GT	17.8	5/1/2023
Gowanus 1-6	J	IC/GT	16.5	5/1/2023
Gowanus 1-7	J	IC/GT	18	5/1/2023
Gowanus 4-1	J	IC/GT	18.9	5/1/2023
Gowanus 4-2	J	IC/GT	18.5	5/1/2023
Gowanus 4-3	J	IC/GT	18.4	5/1/2023
Gowanus 4-4	J	IC/GT	16	5/1/2023
Gowanus 4-5	J	IC/GT	16.6	5/1/2023
Gowanus 4-6	J	IC/GT	18.5	5/1/2023
Gowanus 4-7	J	IC/GT	18.4	5/1/2023
Gowanus 4-8	J	IC/GT	17.2	5/1/2023
Ravenswood 10	J	IC/GT	16	5/1/2023
Ravenswood 11	J	IC/GT	16.1	5/1/2023
South Cairo	G	IC/GT	18.4	5/1/2023
74 St. GT 1	J	IC/GT	19.4	5/1/2023
74 St. GT 2	J	IC/GT	19.9	5/1/2023
Hudson Ave 3	J	IC/GT	16.6	5/1/2023
Hudson Ave 5	J	IC/GT	14.2	5/1/2023
Northport GT	K	IC/GT	11.9	5/1/2023
Port Jefferson GT 01	K	IC/GT	12.7	5/1/2023
Ravenswood 01	J	IC/GT	7.7	5/1/2023
Arthur Kill GT 1	J	IC/GT	12.2	5/1/2025
Gowanus 2-1	J	IC/GT	17.1	5/1/2025
Gowanus 2-2	J	IC/GT	16.9	5/1/2025
Gowanus 2-3	J	IC/GT	19.1	5/1/2025
Gowanus 2-4	J	IC/GT	17.1	5/1/2025

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Unit Name	Energy Area	Unit Type	Summer Capacity (MW)	Retire Date
Gowanus 2-5	J	IC/GT	17.8	5/1/2025
Gowanus 2-6	J	IC/GT	19.7	5/1/2025
Gowanus 2-7	J	IC/GT	19.1	5/1/2025
Gowanus 2-8	J	IC/GT	17.3	5/1/2025
Gowanus 3-1	J	IC/GT	17	5/1/2025
Gowanus 3-2	J	IC/GT	16.9	5/1/2025
Gowanus 3-3	J	IC/GT	18.3	5/1/2025
Gowanus 3-4	J	IC/GT	15.9	5/1/2025
Gowanus 3-5	J	IC/GT	17.3	5/1/2025
Gowanus 3-6	J	IC/GT	15.4	5/1/2025
Gowanus 3-7	J	IC/GT	17.9	5/1/2025
Gowanus 3-8	J	IC/GT	17.8	5/1/2025
Narrows 1-1	J	IC/GT	19.4	5/1/2025
Narrows 1-2	J	IC/GT	17.5	5/1/2025
Narrows 1-3	J	IC/GT	18.5	5/1/2025
Narrows 1-4	J	IC/GT	18.7	5/1/2025
Narrows 1-5	J	IC/GT	20.7	5/1/2025
Narrows 1-6	J	IC/GT	16.3	5/1/2025
Narrows 1-7	J	IC/GT	19	5/1/2025
Narrows 1-8	J	IC/GT	17.7	5/1/2025
Narrows 2-1	J	IC/GT	19.2	5/1/2025
Narrows 2-2	J	IC/GT	16.4	5/1/2025
Narrows 2-3	J	IC/GT	17.5	5/1/2025
Narrows 2-4	J	IC/GT	19.7	5/1/2025
Narrows 2-5	J	IC/GT	20.2	5/1/2025
Narrows 2-6	J	IC/GT	15.3	5/1/2025
Narrows 2-7	J	IC/GT	19	5/1/2025
Narrows 2-8	J	IC/GT	16.4	5/1/2025
59 St. GT 1	J	IC/GT	15.6	5/1/2025
Astoria GT 01	J	IC/GT	13.6	5/1/2025
Nine Mile Point 1	C	NUC	630.6	8/1/2029
R. E. Ginna	B	NUC	579.6	9/1/2029
James A. FitzPatrick	C	NUC	842.9	10/1/2034
Nine Mile Point 2	C	NUC	1288.9	10/1/2046

8.3: Future Generation Mix

The ENELYTIX capacity expansion module determines the long-term optimal electric system expansion through economic additions and retirement of resources in order to satisfy the resource adequacy and environmental constraints described in this report.

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8.3.1: Capacity Expansion Model Generic Additions

The capacity expansion module chooses from a predefined list of potential future generation resources to satisfy resource adequacy and environmental constraints. There are two categories of generation resources that can be added by the capacity expansion module. The first category includes the fossil-fuel based conventional sources of generation that are built in discrete increments based on the size and attributes of the reference unit. The second category includes variable renewable resources such as wind and photovoltaic that the model can build in varying size increments up to their resource potential. Additionally, the capacity expansion module can add battery storage.

TCR relies on unit operational characteristics and cost assumptions for fossil fuel resources from the Analysis Group's ICAP demand curve development report prepared for NYISO.[17] TCR obtained additional unit attributes and cost data from NRELs 2019 Annual Technology Baseline[18] (ATB 2019) study as well as from the underlying capital cost assumptions documentation[19] used by the US Energy Information Administration (EIA) for its 2020 Annual Energy Outlook (AEO 2020). TCR inflates all costs to 2020$ and accounts for any variations in those costs by NYISO zone.

Table 16 below summarizes the potential resource types that TCR has available in its capacity expansion model. Additional performance characteristics of units are described in **Error! Reference source not found.** of this report.

17 NYISO ICAP Study: https://www.nyiso.com/documents/20142/1391705/NYISO%20Staff%20Final%20DCR%20Recommendations%20-September%2015%202016.pdf/c69e3d8a-56f9-d348-3602-e891d8278ebf, https://www.analysisgroup.com/globalassets/content/insights/publishing/analysis_group_nyiso_dcr_final_report_9_13_2016.pdf, Tables 27 & 28 (Performance) Tables 17, 21 & 24 (Costs)

18 NREL ATB: https://atb nrel.gov/

19 EIA Cost Assumptions: https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdfhttps://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf, https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_addendum.pdf

Table 16. Potential Resource Additions

Resource Category	Technology Details	Source of Cost	Energy Area	Capacity	Heat Rate	Overnight Capital Cost	Fixed O&M	Variable O&M
Simple Cycle Peaking Plant	3x0 Siemens SGT-A65	NYISO ICAP Study	J	65.0	9,000	$2,733.60	$48.91	$10.15
			D-F	65.0	9,000	$1,983.90	$23.95	$10.15
			A-C	65.0	9,000	$1,966.56	$23.22	$10.15
			G	65.0	9,000	$2,140.98	$26.47	$10.15
			K	65.0	9,000	$2,255.22	$29.18	$10.15
	1x0 GE 7F.02 (Gas Only, without SCR)	NYISO ICAP Study	D-F	243.0	9,513	$1,103.64	$16.21	$0.96
			A-C	243.0	9,513	$1,093.44	$15.72	$0.96
	1X0 GE 7F.05 (with Dual Fuel and SCR)	NYISO ICAP Study	J	243.0	9,513	$1,853.34	$35.94	$1.55
			D-F	243.0	9,513	$1,350.48	$17.31	$1.55
			A-C	243.0	9,513	$1,341.30	$16.82	$1.55
			G	243.0	9,513	$1,368.84	$18.82	$1.55
			K	243.0	9,513	$1,517.76	$21.05	$1.55
	1X0 GE 7HA.02 (Gas Only, without SCR)	NYISO ICAP Study	D-F	384.0	8,890	$853.74	$12.21	$0.95
			A-C	384.0	8,890	$847.62	$11.91	$0.95
	1X0 GE 7HA.02 (with Dual Fuel and SCR)	NYISO ICAP Study	J	384.0	8,890	$1,380.06	$24.14	$1.43
			D-F	384.0	8,890	$1,075.08	$12.82	$1.43
			A-C	384.0	8,890	$1,071.00	$12.55	$1.43
			G	384.0	8,890	$1,086.30	$13.74	$1.43
			K	384.0	8,890	$1,193.40	$15.17	$1.43
Combined Cycle Gas Turbines	1X1 GE 7HA.02 (with SCR)	NYISO ICAP Study	J	573.0	5,970	$2,000.22	$38.49	$3.60
			D-F	573.0	5,970	$1,449.42	$18.59	$3.60
			A-C	573.0	5,970	$1,429.02	$17.92	$3.60
			G	573.0	5,970	$1,577.94	$20.98	$3.60

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Resource Category	Technology Details	Source of Cost	Energy Area	Capacity	Heat Rate	Overnight Capital Cost	Fixed O&M	Variable O&M
			K	573.0	5,970	$1,868.64	$23.91	$3.60
Biomass (Gas)	Landfill gas 4 x 9.1 MW	EIA Cost Assumptions	NYUP	13.0	9,876	$1,680.00	$27.70	$6.35
			NYCW	3.0	9,876	$2,176.00	$28.10	$6.35
Biomass (Solid)	50-MW Biomass Plant Bubbling Fluidzed Bed	EIA Cost Assumptions	NYUP	45.0	9,876	$4,954.00	$153.50	$4.95
			NYCW	5.0	9,876	$6,703.00	$207.70	$4.95
Energy Storage	Battery Energy Storage System 50MW|100MWh	EIA Cost Assumptions	NYUP	50.0	-	$1,192.00	$25.50	$0.00
			NYCW	50.0	-	$1,220.00	$26.10	$0.00
Hydro	Conventional Hydropower	EIA Cost Assumptions	NYUP	196.0	-	$3,796.00	$57.60	$0.00
PV	Utility Scale, Single Axis Tracking	EIA Cost Assumptions	NYUP	150.0	-	$1,289.00	$15.80	$0.00
			NYCW	150.0	-	$1,531.00	$18.80	$0.00
	Distributed Residential Fixed tilt roof mounted	NREL ATB	NYUP	0.005	-	$3,208.60	$23.10	$0.00
			NYCW	0.005	-	$3,208.60	$23.10	$0.00
Wind	Large Plant Footprint: Great Plains Region 200 MW|2.82 MW WTG	NREL ATB	NYUP	200.0	-	$2,090.00	$30.00	$0.00
Offshore Wind	Fixed-bottom Monopile Foundations 400 MW|10MW WTG	NREL ATB	NYUP	400.0	-	$6,785.00	$137.60	$0.00
			NYCW	400.0	-	$5,596.00	$113.50	$0.00

8.3.2: Maximum Resource Potentials

8.3.2.1: Renewable Generator Additions

TCR relies on NREL assessments of renewable resource potentials and uses data available on NREL's geospatial toolkits and associated publications to establish upper limits on various model-built variable resources for each energy area within the NYISO footprint.

Although NREL's resource potentials are typically available by state[20], TCR obtained more granular county level data to re-aggregate state potentials into potentials by energy areas. The methodologies for calculating potentials are described below:

- **Onshore wind and photovoltaic**: potentials for onshore wind and PV are obtained from NRELs REV study[21]. Granular county level data for annual energy and nameplate capacity for onshore wind, PV, and concentrated solar power were obtained directly from NREL. The potentials were aggregated to obtain potentials by energy zone and reduced by the quantity of PV and onshore wind already existing in the NYISO model.
- **Rooftop PV:** potentials are obtained from NRELs Solar For All Toolkit[22] which provides an estimate of annual energy that may be obtained through rooftop PV installations by county. Annual energy is converted to nameplate capacity using energy area specific capacity factors to obtain nameplate potential for rooftop PV. Finally, the potential of rooftop PV is reduced by the quantity of rooftop PV already existing in the MISO model.
- **Offshore wind and Hydropower**: potentials for offshore wind and hydropower by state are obtained from NREL's GIS-based technical potential study[23].

  For offshore wind, TCR assumed distributions of state potentials to each of the energy areas proportionate to the length of the coastlines. The offshore wind potentials are reduced by the quantity of existing offshore wind in the NYISO model.

  For Hydropower, TCR assumed similar distributions of state potentials to each of the energy areas proportionate to their approximate footprints. Since the assessment of Hydropower potential is on a site-specific basis it is assumed to already account for hydropower that has already been built.
- **Biopower**: potentials for biogas and biomass are obtained from NRELs biopower geospatial toolkit[24] which provides annual estimates of tons per year of biomass and biogas resources by county. Conversion factors to annual energy and nameplate capacity are available within the toolkit to obtain the nameplate potential for biomass and biogas resources.

Table 17 below provides the final modeled resource potentials for variable resources by NYISO energy area.

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20 Renewable Energy Technical Potential. https://www nrel.gov/gis/re-potential html
21 Renewable Energy Potential (reV) Model. https://www.nrel.gov/docs/fy19osti/73067.pdf
22 Solar for All Data Explorer. https://maps nrel.gov/solar-for-all/?aL=0&bL=clight&cE=0&lR=0&mC=38.870832155646326%2C-98.34521484375001&zL=5
23 U.S. Renewable Energy Technical Potentials: A GIS Study. https://www nrel.gov/docs/fy12osti/51946.pdf
24 Biopower Atlas. https://maps nrel.gov/biopower/?aL=wyQpUn%255Bv%255D%3Dt&bL=clight&cE=0&lR=0&mC=40.21244%2C-91.625976&zL=4

Table 17. Technical Potential for Installed Renewable Capacity by Resource Type and State (MW)

Row Labels	Rooftop PV	Hydro	Biogas	Offshore Wind	Utility PV	Biomass	Onshore Wind
A	952	196	13	6,689	213,868	45	17,472
B	780	95	6	1,920	86,793	26	7,665
C	729	241	12	1,920	156,834	45	20,844
D	25	91	1,320	-	28,630	6	5,108
E	173	469	7	690	299,180	38	31,209
F	285	254	7	-	77,666	38	15,536
G	474	123	5	-	38,564	18	4,580
H	407	-	3	-	497	5	-
I	370	-	3	-	497	5	-
J	1,591	-	13,886	64,738	-	78	-
K	1,480	-	10	65,798	15,865	31	-
NYISO Total	*7,266*	*1,469*	*15,272*	*141,755*	*918,393*	*335*	*102,413*

8.3.2.2: Fossil Fuel Generator Additions

For thermal generation additions, TCR assumes that new buildable capacity in each area is approximately four time the current installed capacity of all current thermal capacity in that area. TCR assumes that each zone has access to at least one thermal unit of each fossil fuel technology type listed in Table 16 and models multiple units of each in order to meet the zones target requirement.

8.3.2.3: Financial Assumptions for Generic Resource Additions

The base case uses common financing assumptions for all market-driven unit additions, both fossil fuel and renewable. These assumptions include a 20-year financing period, and a real after tax weighted average cost of capital (WACC) of 6.0%. The WACC is based on the results of an analysis by Concentric Energy Advisors prepared for ISO New England, which assumes uncontracted merchant development, and is based on costs of equity and debt that are commensurate with a merchant project's perceived risks of cost recovery in the market, which are higher than those of a project whose revenues are contracted under a PPA.[25] The use of a WACC based on merchant rather than contracted development reflects the Base Case assumption that only merchant development will be possible because the market will not bring about the development of resources with long-term PPAs in the absence of mandated procurements such as 83C.

8.3.3: Capacity Expansion Unit Retirement

Over the study period ENELYTIX analyzes the economics of existing thermal units to determine whether their projected revenues compared to their projected variable operating costs justifies retiring any of those units. The ENELYTIX capacity expansion optimization algorithm evaluates the trade-off between the need to keep the generating unit online to meet resource adequacy requirements against

25 ISO-NE CONE and ORTP Analysis. Concentric Energy Advisors. Prepared for ISO New England, January 13, 2017, p. 48.

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making an investment into another generating unit to satisfy environmental constraints and/or producing energy at lower operating cost.

CHAPTER 9: Generating Unit Operating Characteristics

9.1: Generator Aggregation

To optimize model computation time, TCR aggregates all units below 20 MWs by type, fuel and energy area into a smaller set of units. Full load heat rates for the aggregates are calculated as the capacity weighted average of the individual units and all other parameters are inherited from the unit type.

9.2: Thermal Unit Characteristics

Thermal generation characteristics are generally determined by a generator's technology and fuel type. These characteristics include heat rate curve shape, non-fuel operation and maintenance costs, startup costs, forced and planned outage rates, minimum up and down times, and quick start, regulation and spinning reserve capabilities.

TCR developed generator outage and heat rate data from information by similar unit type as obtained from both the North American Electric Reliability Corporation (NERC) Generating Availability Report and power industry data provided by S&P Global.

Each thermal unit type has a distinct normalized incremental heat rate curve. The normalized heat rate curve is scaled by the full load heat rate (FLHR) to produce unit specific heat curve. Table 18 summarizes the shape of normalized heat rate curve used in ENELYTIX.

Table 18. Normalized Incremental Heat Rate Curve

Unit Type	Blocks (Total)	Block	Capacity Range (% of Max)	Heat Rate (% of FLHR)
CT	1	1	100%	100%
CC	4	1	50%	113%
		2	51% ~ 67%	75%
		3	68% ~ 83%	86%
		4	84% ~ 100%	100%
ST (Coal)	4	1	0% ~ 50%	106%
		2	51% ~ 65%	90%
		3	66% ~ 95%	95%
		4	96% ~ 100%	100%
ST (Other)	4	1	25%	118%
		2	26% ~ 50%	90%
		3	51% ~ 80%	95%
		4	81% ~ 100%	100%

As an example, for a 500 MW CC with a 7,000 Btu/KWh FLHR, the minimum load block would be its minimum generation of 250 MW at a heat rate of 7,910 Btu/KWh, the 2nd incremental block would be 251 MW ~ 335 MW at a heat rate of 5,250 Btu/KWh, the 3rd increment would be 336 MW ~ 415 MW at a heat rate of 6,020 Btu/KWh, and the final block would be 416 MW ~ 500 MW at a heat rate of 7,000 Btu/KWh.

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Table 19 summarizes other operating character assumptions by unit type for thermal generators. The abbreviations in the unit type column are structured as follows: First 2-3 characters identify the technology type, the next 1-2 characters identify the fuel used (gas, oil, coal, biomass, refuse) and the numbers identify the size of generating units mapped to that type.

Table 19. Other Thermal Unit Operating Parameters by Unit Type

Unit Type	Min On Time (Hr)	Min Off Time (Hr)	EFORd (%)	VOM ($/MWh)	Startup Cost Cold ($/MW-start)
CCg100 (0-100MW)	6	8	4.29	2.5	35
CCg100+ (100-9999MW)	6	8	4.29	2.5	35
CCgo100 (0-100MW)	6	8	4.29	2.5	35
CCgo100+ (100-9999MW)	6	8	4.29	2.5	35
Cco+ (0-9999MW)	6	8	8.58	2.5	35
CCr+ (0-500MW)	1	1	4.29	2.5	35
GTb20 (0-20MW)	1	1	11.28	10	--
GTg20 (0-20MW)	1	1	18.6	10	--
GTg50 (20-50MW)	1	1	12.97	10	--
GTgo20 (0-20MW)	1	1	18.6	10	--
GTgo50 (20-50MW)	1	1	12.97	10	--
GTgo50+ (50-9999MW)	1	1	9.29	10	--
GTo20 (0-20MW)	1	1	18.6	10	--
GTo50 (20-50MW)	1	1	12.97	10	--
GTo50+ (50-9999MW)	1	1	9.29	10	--
GTo20 (0-20MW)	1	1	18.6	10	--
GTo50 (20-50MW)	1	1	12.97	10	--
GTr20 (0-20MW)	1	1	11.28	10	--
ICb+ (0-500MW)	1	1	11.63	10	--
ICg20 (0-20MW)	1	1	21.16	10	--
ICg50+ (50-500MW)	1	1	11.54	10	--
ICgo20 (0-20MW)	1	1	21.16	10	--
ICgo50 (20-50MW)	1	1	11.54	10	--
ICgo50 + (50-500MW)	1	1	11.54	10	--
ICo20 (0-20MW)	1	1	21.16	10	--
ICo50+ (50-500MW)	1	1	11.54	10	--
ICog20 (20-50MW)	1	1	11.54	10	--
ICo50 (0-50MW)	1	1	11.54	10	--
ICr+ (0-500MW)	1	1	11.63	2	--
NUC-BWR1000MW+	164	164	2.19	0	90
NUC-BWR(800-1000MW)	164	164	1.66	0	90
NUC-BWR(400-799MW)	164	164	3.27	0	90
NUC-PWR1000MW+	164	164	4.02	0	90
NUC-PWR(400-799MW)	164	164	3.02	0	90
STb+ (0-500MW)	10	8	10.26	0	35

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Unit Type	Min On Time (Hr)	Min Off Time (Hr)	EFORd (%)	VOM ($/MWh)	Startup Cost Cold ($/MW-start)
STc100 (0-100MW)	24	12	8.32	5	45
STc250 (100-250MW)	24	12	6.47	4	45
STc600 (250-600MW)	24	12	7.83	3	45
STg100 (0-100MW)	10	8	10.34	6	40
STg200 (100-200MW)	10	8	8.42	5	40
STg600 (200-600MW)	10	8	8.35	4	40
STgo100 (0-100MW)	10	8	10.34	6	40
STgo200 (100-200MW)	10	8	8.42	5	40
STgo600 (200-600MW)	10	8	8.35	4	40
STo100 (0-100MW)	10	8	10.34	6	40
STo200 (100-200MW)	10	8	8.42	5	40
STo600 (200-600MW)	10	8	8.35	4	40
STo600+ (600-9999MW)	10	8	14.55	3	40
STr+ (0-500MW)	10	8	10.26	2	40

9.2.1: Nuclear Unit Operating Characteristics

Nuclear plants are modeled as special thermal units in ENELYTIX. In general, nuclear facilities are treated as must run units and assumed to run except for periods during generator maintenance and forced outage. Current refueling schedules are obtained from roadtech.com[26]. Future schedules are estimated per specified periodicity.

9.3: Hydro Electric Generator Characteristics

TCR models hydro electric generators as energy constrained generators that output energy in relation to daily pattern of water flow, i.e. the minimum and maximum generating capability and the total energy for each plant. TCR obtains historic hydro generation MWh from EIA and S&P Global database. Based on this historic information, TCR develops daily maximum energy output for each hydro power plant in NYISO Subject to this maximum energy output constraint, TCR allows ENELYTIX® to optimize hourly energy output of each hydro electric generator to minimize system-wide production costs in each hour of the day.

9.4: Pumped Hydro Storage Facilities

TCR models pumped storage with the following specifications obtained from the National Hydroelectric Power Resource Study prepared for the U.S. Army Engineer Institute of Water Resources.

- Max Storage: Unit Capacity * Number of Storage hours
- Min Storage: 10% of Max Storage
- Min MW: Pumping Capacity

26 https://www.roadtechs.com/shutdown/shutdown.php?region=n

- Efficiency: Annual Output/Annual Pumping Energy

9.5: Wind Facilities

Wind generation is represented as hourly generation profile in ENELYTIX®. TCR assembles wind generation profiles from the National Renewable Energy Laboratory (NREL)'s Wind Integration National Dataset (WIND) Toolkit dataset based on 2012 weather data.[27] TCR maps each wind power plant to the nearest NREL site based on the plant's location. For wind plants with known historic capacity factor, TCR further screens for NREL wind sites that have capacity factor within delta of 2% from historical average capacity factor inside a 50-mile radius range from the plant's location. The resulting normalized NREL site schedule is scaled to the installed capacity of the corresponding wind site and then calendar-shifted for each forecast year making it synchronized with load profiles and interchange schedules.

9.6: Solar Photovoltaics Facilities

Like wind facilities, photovoltaic (PV) generators are also represented as hourly generation profiles in ENELYTIX®. TCR obtains solar irradiation data from weather station closest to a PV generator's location and uses NREL's PVWatts® Calculator to estimate the site's energy production. TCR assumes all utility scale PV facilities are fixed array installations with characteristics summarized in Table 20.

Table 20. Photovoltaic Parameter Assumptions

PV Parameter	Assumption
Elevation (m)	5
Module Type	Standard
Array Type	Fixed (Open Rack)
Array Tilt (deg)	20
Array Azimuth (deg)	180
System Losses (%)	14
Invert Efficiency (%)	96

27 https://www.nrel.gov/grid/wind-toolkit.html

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CHAPTER 10: Fuel Cost

10.1: Natural Gas Prices

10.1.1: Spot Gas Prices in New York

TCR obtained a monthly spot gas price forecast for natural gas market hubs from Wood Mackenzie.[28] However, a proper modeling of price diversity among gas-fired generators serving NYISO requires forecasts for more hubs than are provided in the Wood Mackenzie outlook. To extend the Wood Mackenzie forecast to the required hubs, TCR obtained historic spot price data for each relevant hub for the past 5 years. Using historic spot price data, for each relevant hub in the NYISO region TCR identified the highest price-correlated hub which had a Wood Mackenzie forecast and calculated a percentage difference in the historic spot price between the two hubs.

The projections of natural gas spot prices at each market hub equals the Wood Mackenzie projection of Henry Hub price plus the Wood Mackenzie projection of monthly basis differential to each market hub from the Henry Hub. For hubs with no Wood Mackenzie forecast, the spot price equals the projection at the highest-correlated hub with a Wood Mackenzie forecast, multiplied by the percentage difference in price between the hubs from the historic spot price data. Forecasted NYISO market hub and Henry Hub prices are shown in **Error! Reference source not found.**.

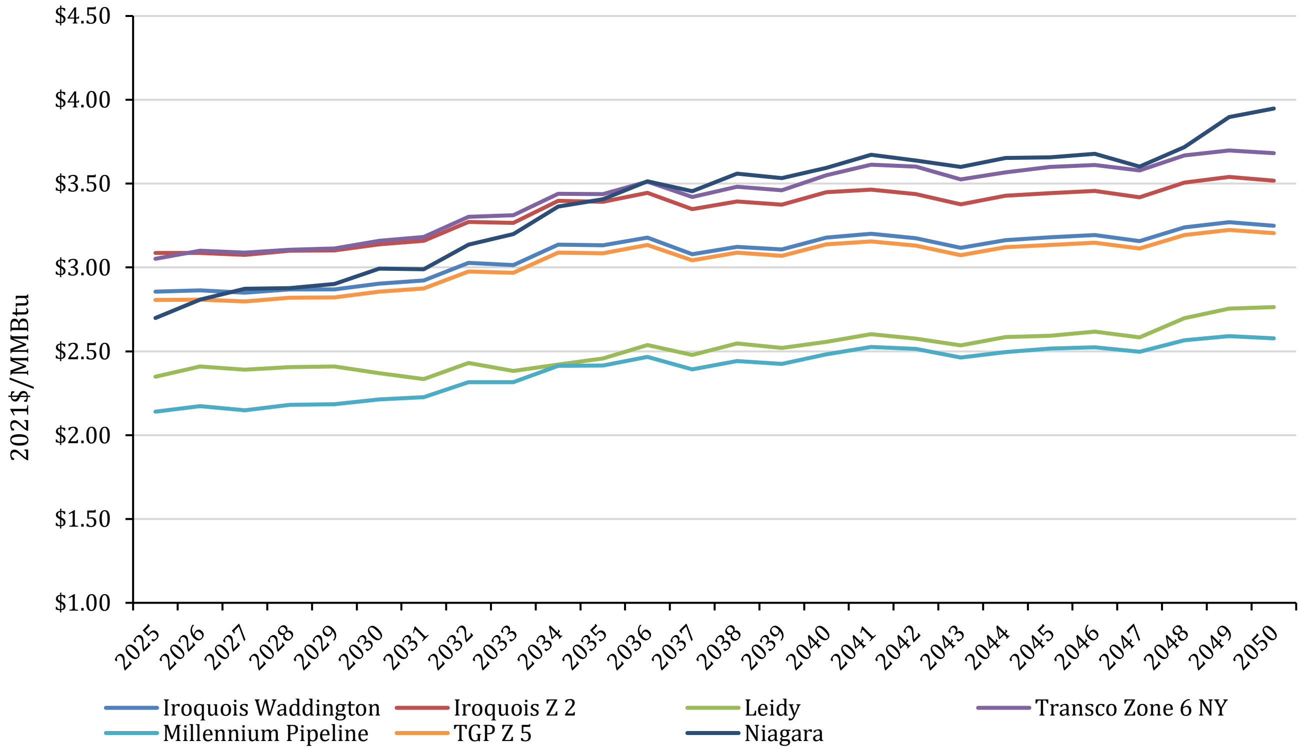

Figure 2. TCR Forecasted Yearly Spot Natural Gas Prices by Hub (2021$/MMBtu)

28 North America gas gas 2021 outlook to 2050. Wood Mackenzie

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Figure 3 **Error! Reference source not found.**shows the TCR forecast of monthly spot prices at natural hubs serving NYISO. This figure indicates that the TCR forecast of gas prices to electric generating units shows significant variation between winter months and summer months.

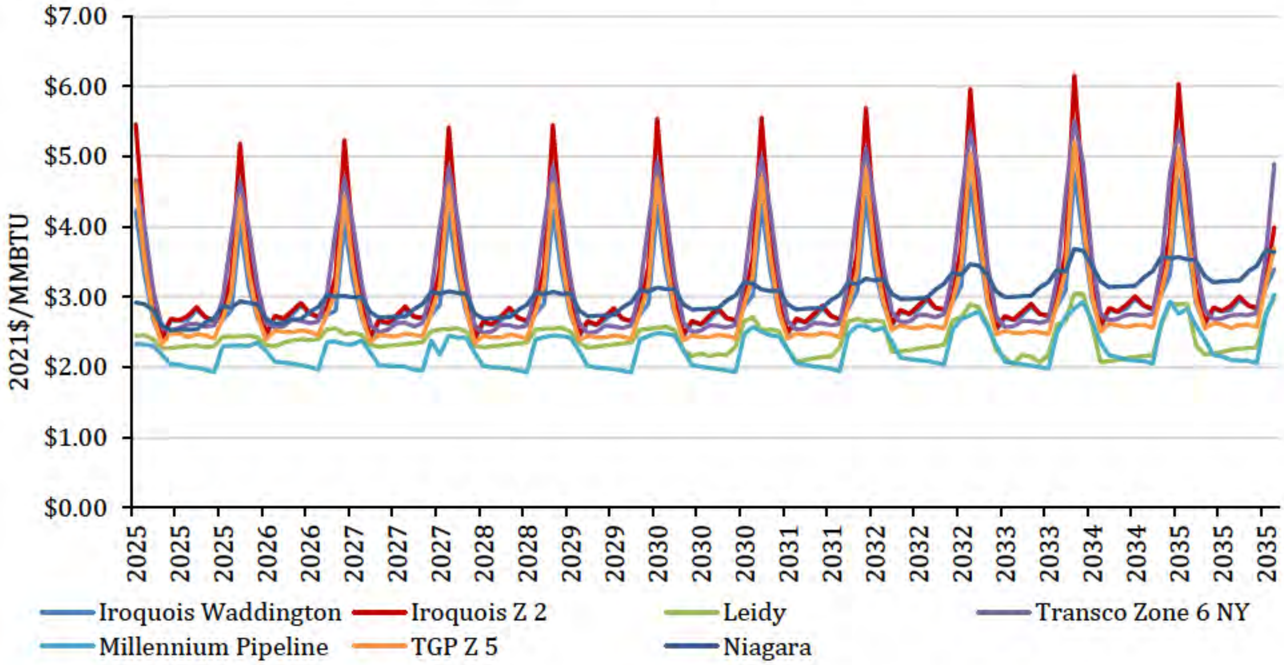

Figure 3. TCR Forecasted Monthly Spot Natural Gas Prices by Hub (2021$/MMBtu)

10.1.2: Natural Gas Price Adders

TCR adds plant level fuel prices adders for all natural gas fired power plants based on each power plants' supplier type (pipeline connected vs. LDC served) and unit type (baseload units vs peaking units). These adders are shown in Table 21.

Table 21. Natural Gas Power Plant Fuel Adders ($/MMBtu)

Unit Type	Directly Connected to Pipeline	Served by LDC
Baseload Units	0.05	0.2
Peaking Units	0.15	0.4

10.2: Fuel Oil Prices

TCR obtained annual crude oil projections from Wood Mackenzie's North America gas 2021 outlook to 2050.[29] In order to extend these projections to distillate (No. 2) and residual (No. 6) fuel oil, TCR used historic fuel prices obtained from the EIA. TCR calculated price ratios between the fuel oils and crude oil using a five-year historical monthly average for the daily spot prices for crude oil (Cushing, OK WTI) and No. 2 heating oil (NY Harbor spot price), and the monthly U.S. Residual Fuel Oil wholesale price.

29 North America gas gas 2021 outlook to 2050. Wood Mackenzie

The projections for No. 2 fuel oil (FO2) and No. 6 fuel oil (FO6) equal the Wood Mackenzie forecast for crude oil multiplied by the historic price ratios. The projection of fuel oil prices is shown in Figure 4.

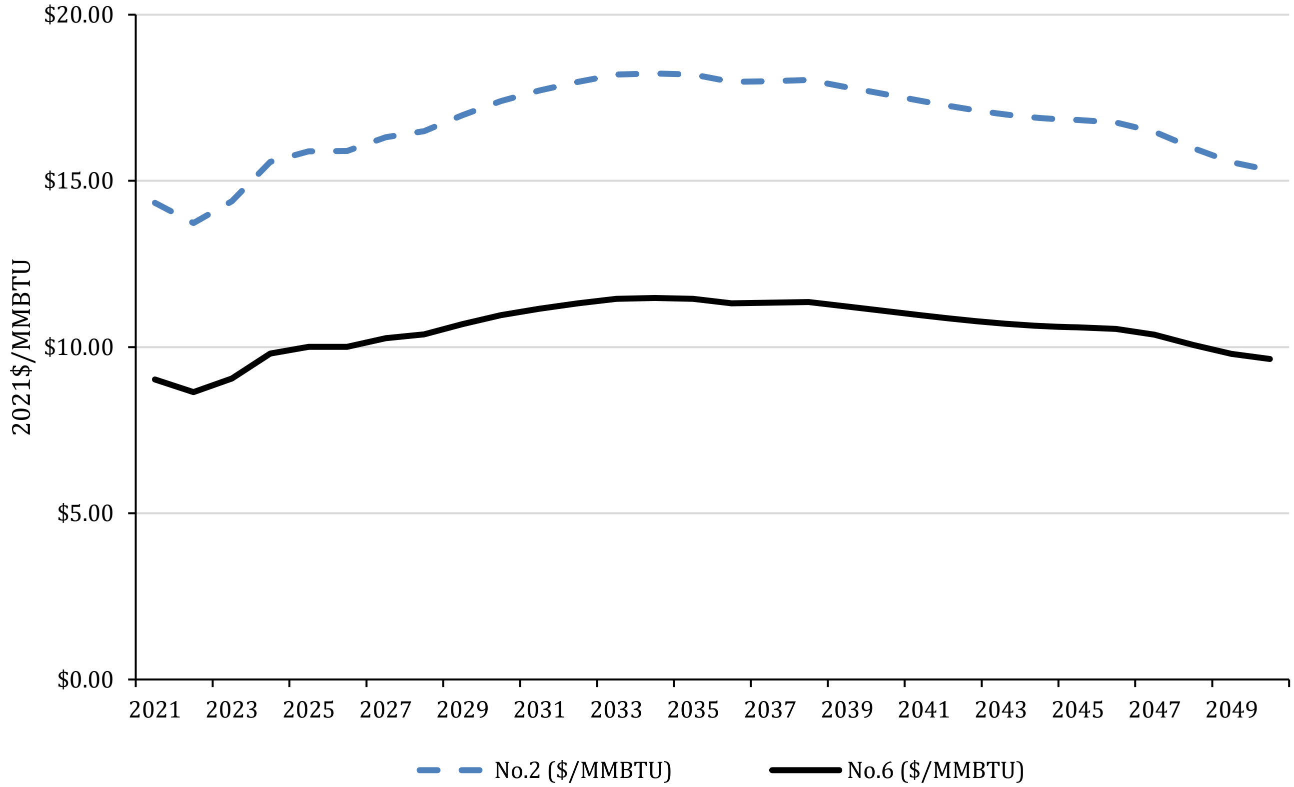

Figure 4. Projection of Fuel Oil Price (2021$/MMBtu)

10.3: Uranium Prices

TCR develops uranium prices using the pricing calculator created by the Bulletin of the Atomic Scientist[30]. The calculator estimates the cost of electricity assuming the nuclear fuel cycle is "Once-Through". TCR omits all capital related cost associated with the cost of electricity from the calculator. The resulting uranium price is 0.99 Nominal $/MMBtu, which TCR assumed to be fixed.

10.4: Coal Prices

There are no coal units operational in NYISO during the 2025-2050 study period.

30 http://thebulletin.org/nuclear-fuel-cycle-cost-calculator/model

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CHAPTER 11: Emission Rates and Allowances

The two active emission control programs in the NYISO footprint are the Regional Greenhouse Gas Initiative (RGGI) programs for Carbon dioxide and the Cross-State Air Pollutions Rule (CSAPR) for sulfur dioxide and nitrogen oxides emissions. TCR models both programs in this model.

11.1: Emission Programs

11.1.1: Regional Greenhouse Gas Initiative

New York participates in the Regional Greenhouse Gas Initiative (RGGI).TCR developed its RGGI CO_2 allowance price assumptions based on the Wood Mackenzie 2021 gas outlook to 2050, which includes a RGGI price forecast.[31] Figure 5 plots the Base Case RGGI price assumption.

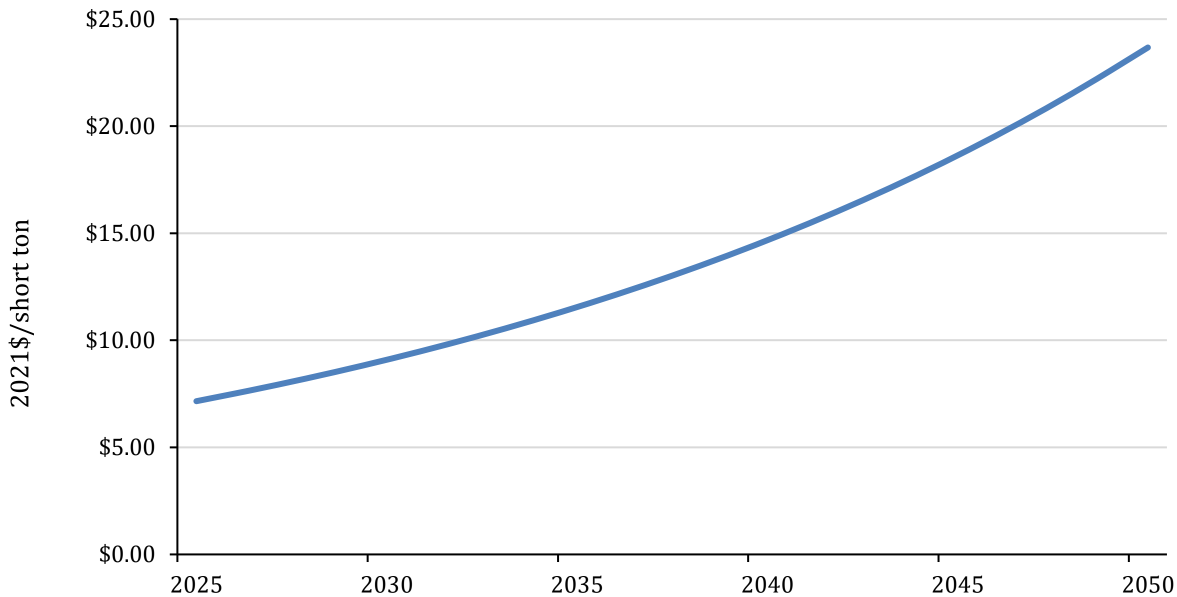

Figure 5. RGGI Price Projection, 2025-2050 (2021$/short ton)

11.1.2: Cross State Air Pollution Rule

The state of New York is covered by Cross State Air Pollution Rule (CSAPR) for both fine particles (SO_2 and annual NO_x) and ozone (seasonal NO_x). Figure 6 shows a map of CSAPR program coverage. In CSAPR terminology, "Seasonal NO_x" emission is the summer season from May 1 to October 31 while "Annual NO_x" emission refers to the rest of the year.

31 North America gas gas 2021 outlook to 2050. Wood Mackenzie

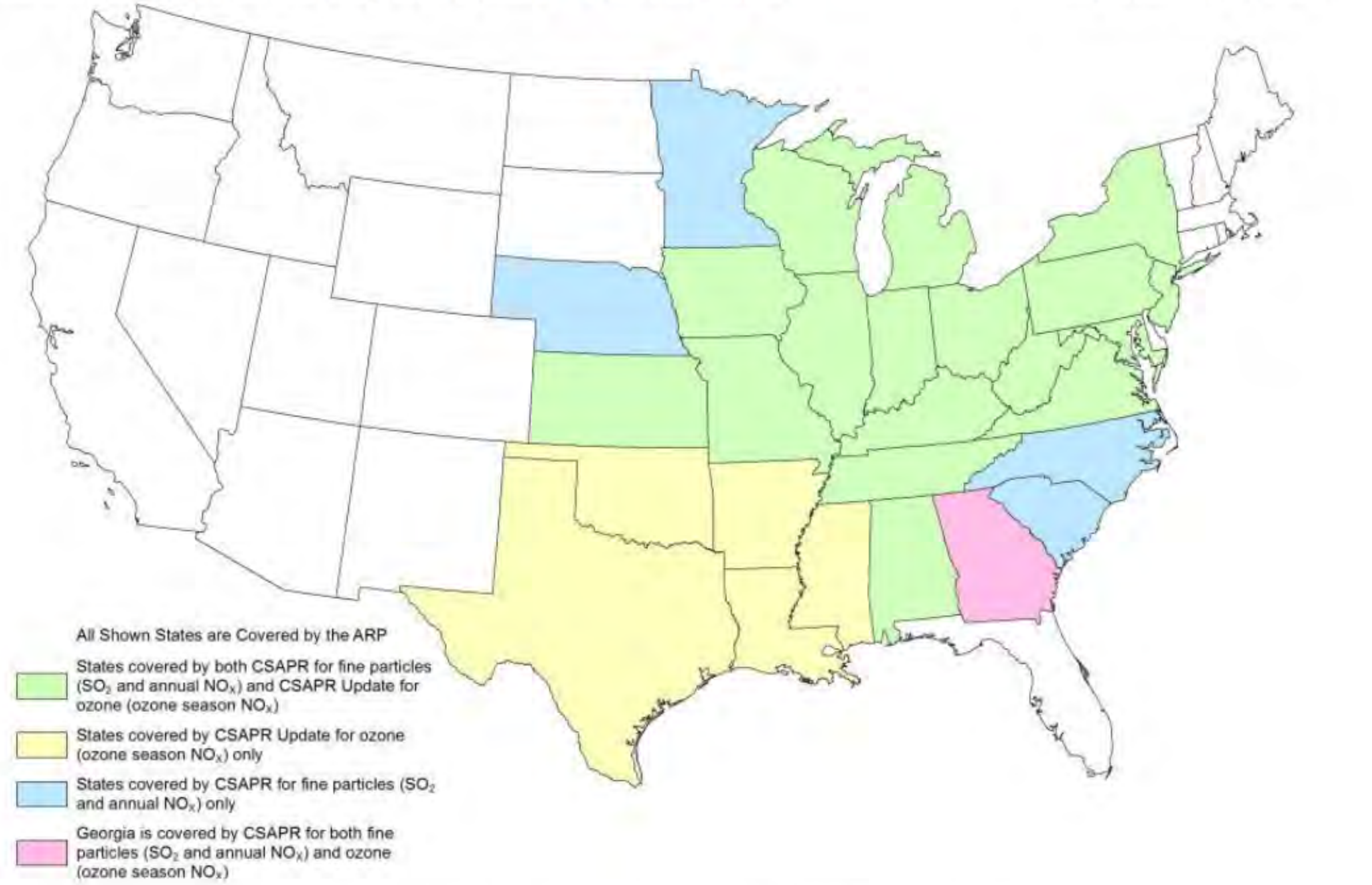

Figure 6. Map of States Covered by CSAPR Programs

Source: EPA

TCR obtains CSAPR programs' emission allowance prices from S&P Global's assessment of CSAPR program. Table 22 summarizes CSAPR prices used in the model which is assumed to be constant over the forecast.

Table 22. CSAPR Emission Allowance Prices

Emission Type	$ per Allowance	Allowance	$/lbs
CSAPR NOx Seasonal	$2,755	1 Allowance is 2000lbs	$1.38
CSAPR NOx Annual	$2.31	1 Allowance is 2000lbs	$0.00115
CSAPR SO2 Group 1	$1.73	1 Allowances is 2000lbs	$0.00086
CSAPR SO2 Group 2	$2.57	1 Allowances is 2000lbs	$0.00129

11.2: Emission Rates

TCR obtains generator unit level emission rates from three sources: S&P Global's historic unit emissions data base, S&P Global's simulated Generator Supply Curve (GSC) data base and EIA's generic future unit characteristics. For existing thermal units, TCR uses S&P Global's historic emission rates. For existing units without historic data, TCR uses GSC emissions data. Finally, for existing units without historic and GSC data, and future units not yet operating, TCR uses EIA's generic rates.

GLOSSARY

Term	Definition
10MNSR	10 Minute Non-Spinning Reserve
10MSR	10 Minute Spinning Reserve
30MR	30 Minute Reserves
AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
BIO	Biomass
BMPV/ BTMPV	Behind-the-meter Photovoltaic
CC	Combined Cycle
CES	Clean Energy Standard
CLCPA	Climate Leadership and Community Protection Act
CSAPR	Cross-State Air Pollutions Rule
CT	Combustion Turbine
DA	Day-ahead
DFO/NO. 2	Distillate Fuel Oil
E&AS	Energy and Ancillary Services
EDC	Electric Distribution Company
EE	Energy Efficiency
EFORd	Effective Forced Outage Rates
EGU	Electric Generating Units
EIA	Energy Information Administration
eNode	Electric Node
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FLHR	Full Load Heat Rate
GIS	Geographic Information System
GHG	Greenhouse Gas
Gold Book	NYISO's Load & Capacity Data Report

Term	Definition
GSC	Generator Supply Curve
GT	Gas Turbine
GWSA	Global Warming Solutions Act
HD	Hydro Power
IC	Internal Combustion (reciprocating) Engine
ICAP	Installed Capacity
IOU	Investor Own Utilities
IRM	Installed Reserve Margin
Kirchhoff's laws	The current law and the voltage law
LCR	Locational Minimum Installed Capacity Requirement
LDC	Load Distribution Company
LSE	Load Serving Entity
NERC	North American Electric Reliability Corporation
NG	Natural Gas
NREL	National Renewable Energy Laboratory
NYGATS	New York Generation Attribute Tracking System
NYSERDA	New York State Energy Research and Development Authority
NYSRC	New York State Reliability Council
PPA	Power Purchase Agreement
PS	Pumped Storage Unit
PV	Photovoltaic
PVWatts®	NREL's PV Calculator
REC	Renewable Energy Certificate, Renewable Energy Credit
RES	Renewable Energy Standard
REV	Renewable Energy Potential (reV) Model
RFO/NO. 6	Residual Fuel Oil
RFP	Requests for Proposal
RGGI	Regional Greenhouse Gas Initiative
RT	Real-time

Term	Definition
ST	Steam Turbine
SUN	Solar Powered
TARA tool	Transmission Adequacy & Reliability Assessment tool
TGP	Tennessee Gas Pipeline
TRE	Total Renewable Energy
UCAP	Unforced Capacity
URM	Unforced Capacity Reserve Margin
VDER	Value of Distributed Energy Resources
VOM	Variable Operation & Maintenance
WACC	weighted average cost of capital
WAT	Water
WIND (NREL)	Wind Integration National Dataset
WT	Wind Turbine

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APPENDIX A: Fuel Price Forecast

A.1: Natural Gas Prices

Date	Iroquois Waddington	Iroquois Z 2	Leidy	Millennium Pipeline	Niagara	TGP Z 5	Transco Zone 6 NY
1/1/2025	$4.23	$5.45	$2.44	$2.33	$2.92	$4.62	$4.67
2/1/2025	$3.34	$3.92	$2.46	$2.32	$2.89	$3.54	$4.01
3/1/2025	$2.67	$2.86	$2.40	$2.30	$2.81	$2.71	$3.09
4/1/2025	$2.38	$2.41	$2.27	$2.17	$2.60	$2.33	$2.56
5/1/2025	$2.66	$2.69	$2.27	$2.04	$2.52	$2.47	$2.52
6/1/2025	$2.66	$2.67	$2.28	$2.04	$2.53	$2.48	$2.56
7/1/2025	$2.67	$2.73	$2.30	$2.00	$2.53	$2.43	$2.61
8/1/2025	$2.82	$2.85	$2.31	$2.00	$2.53	$2.47	$2.62
9/1/2025	$2.71	$2.71	$2.29	$1.96	$2.63	$2.46	$2.57
10/1/2025	$2.65	$2.67	$2.30	$1.93	$2.70	$2.41	$2.59
11/1/2025	$2.67	$2.77	$2.44	$2.30	$2.87	$2.69	$2.97
12/1/2025	$2.81	$3.31	$2.44	$2.30	$2.85	$3.06	$3.86
1/1/2026	$4.02	$5.19	$2.43	$2.31	$2.94	$4.39	$4.65
2/1/2026	$3.16	$3.70	$2.45	$2.30	$2.92	$3.35	$3.98
3/1/2026	$2.70	$2.89	$2.42	$2.35	$2.89	$2.75	$3.17
4/1/2026	$2.45	$2.48	$2.31	$2.23	$2.69	$2.39	$2.63
5/1/2026	$2.71	$2.73	$2.30	$2.08	$2.61	$2.52	$2.56
6/1/2026	$2.68	$2.69	$2.35	$2.06	$2.63	$2.50	$2.58
7/1/2026	$2.75	$2.80	$2.38	$2.05	$2.68	$2.49	$2.68
8/1/2026	$2.88	$2.91	$2.40	$2.03	$2.68	$2.52	$2.66
9/1/2026	$2.77	$2.77	$2.39	$2.00	$2.78	$2.51	$2.63
10/1/2026	$2.70	$2.72	$2.40	$1.96	$2.85	$2.45	$2.65
11/1/2026	$2.74	$2.85	$2.54	$2.36	$3.03	$2.76	$3.06
12/1/2026	$2.81	$3.31	$2.55	$2.36	$3.00	$3.07	$3.95
1/1/2027	$4.06	$5.23	$2.47	$2.32	$3.01	$4.43	$4.69
2/1/2027	$3.23	$3.79	$2.48	$2.33	$2.99	$3.42	$4.02
3/1/2027	$2.70	$2.89	$2.46	$2.38	$2.99	$2.74	$3.19
4/1/2027	$2.41	$2.44	$2.31	$2.21	$2.78	$2.36	$2.61
5/1/2027	$2.64	$2.67	$2.29	$2.03	$2.70	$2.46	$2.50
6/1/2027	$2.62	$2.63	$2.30	$2.02	$2.71	$2.45	$2.53
7/1/2027	$2.68	$2.74	$2.31	$2.01	$2.72	$2.44	$2.63
8/1/2027	$2.83	$2.87	$2.33	$2.01	$2.72	$2.48	$2.63
9/1/2027	$2.71	$2.72	$2.34	$1.96	$2.82	$2.46	$2.58
10/1/2027	$2.68	$2.70	$2.35	$1.95	$2.90	$2.44	$2.63
11/1/2027	$2.74	$2.84	$2.51	$2.38	$3.07	$2.76	$3.07
12/1/2027	$2.88	$3.39	$2.54	$2.18	$3.05	$3.15	$4.00
1/1/2028	$4.20	$5.42	$2.54	$2.45	$3.08	$4.59	$4.84
2/1/2028	$3.33	$3.90	$2.55	$2.42	$3.05	$3.52	$4.13

REDACTED

Date	Iroquois Waddington	Iroquois Z 2	Leidy	Millennium Pipeline	Niagara	TGP Z 5	Transco Zone 6 NY
3/1/2028	$2.79	$2.99	$2.51	$2.42	$3.04	$2.84	$3.24
4/1/2028	$2.40	$2.43	$2.31	$2.20	$2.76	$2.35	$2.59
5/1/2028	$2.63	$2.65	$2.28	$2.02	$2.69	$2.45	$2.49
6/1/2028	$2.60	$2.61	$2.29	$2.00	$2.70	$2.42	$2.51
7/1/2028	$2.67	$2.72	$2.31	$1.99	$2.70	$2.42	$2.60
8/1/2028	$2.81	$2.85	$2.32	$1.98	$2.71	$2.46	$2.59
9/1/2028	$2.70	$2.70	$2.34	$1.95	$2.81	$2.44	$2.56
10/1/2028	$2.65	$2.66	$2.35	$1.93	$2.89	$2.40	$2.59
11/1/2028	$2.76	$2.86	$2.53	$2.40	$3.06	$2.78	$3.09
12/1/2028	$2.91	$3.42	$2.55	$2.43	$3.04	$3.17	$4.03
1/1/2029	$4.22	$5.45	$2.55	$2.45	$3.07	$4.61	$4.86
2/1/2029	$3.36	$3.93	$2.56	$2.44	$3.04	$3.55	$4.18
3/1/2029	$2.75	$2.94	$2.50	$2.42	$3.04	$2.79	$3.25
4/1/2029	$2.44	$2.47	$2.34	$2.23	$2.81	$2.38	$2.63
5/1/2029	$2.63	$2.65	$2.28	$2.02	$2.72	$2.45	$2.49
6/1/2029	$2.60	$2.61	$2.29	$2.00	$2.73	$2.42	$2.50
7/1/2029	$2.67	$2.72	$2.31	$1.99	$2.74	$2.42	$2.59
8/1/2029	$2.80	$2.83	$2.32	$1.97	$2.74	$2.45	$2.58
9/1/2029	$2.68	$2.69	$2.33	$1.95	$2.85	$2.43	$2.56
10/1/2029	$2.64	$2.66	$2.35	$1.92	$2.92	$2.40	$2.59
11/1/2029	$2.75	$2.85	$2.53	$2.40	$3.10	$2.77	$3.09
12/1/2029	$2.91	$3.42	$2.55	$2.44	$3.07	$3.17	$4.05
1/1/2030	$4.30	$5.54	$2.56	$2.49	$3.13	$4.69	$4.93
2/1/2030	$3.39	$3.97	$2.58	$2.47	$3.11	$3.59	$4.25
3/1/2030	$2.76	$2.95	$2.53	$2.45	$3.11	$2.80	$3.29
4/1/2030	$2.44	$2.47	$2.25	$2.24	$2.89	$2.39	$2.63
5/1/2030	$2.63	$2.66	$2.16	$2.03	$2.82	$2.45	$2.50
6/1/2030	$2.60	$2.61	$2.19	$2.01	$2.82	$2.43	$2.52
7/1/2030	$2.67	$2.73	$2.16	$1.99	$2.83	$2.43	$2.60
8/1/2030	$2.80	$2.84	$2.18	$1.97	$2.84	$2.46	$2.59
9/1/2030	$2.70	$2.70	$2.17	$1.95	$2.95	$2.44	$2.56
10/1/2030	$2.65	$2.67	$2.29	$1.93	$3.02	$2.41	$2.60
11/1/2030	$2.86	$2.97	$2.65	$2.47	$3.21	$2.89	$3.22
12/1/2030	$3.02	$3.56	$2.71	$2.57	$3.19	$3.30	$4.23
1/1/2031	$4.31	$5.55	$2.52	$2.50	$3.11	$4.70	$4.98
2/1/2031	$3.39	$3.97	$2.54	$2.46	$3.08	$3.58	$4.23
3/1/2031	$2.76	$2.95	$2.51	$2.44	$3.09	$2.80	$3.29
4/1/2031	$2.46	$2.49	$2.24	$2.26	$2.90	$2.41	$2.66
5/1/2031	$2.66	$2.69	$2.08	$2.05	$2.82	$2.48	$2.53
6/1/2031	$2.64	$2.64	$2.10	$2.03	$2.83	$2.46	$2.55
7/1/2031	$2.70	$2.76	$2.12	$2.01	$2.84	$2.45	$2.62
8/1/2031	$2.84	$2.88	$2.14	$2.00	$2.84	$2.49	$2.62
9/1/2031	$2.72	$2.73	$2.15	$1.98	$2.96	$2.47	$2.60
10/1/2031	$2.66	$2.68	$2.28	$1.94	$3.03	$2.42	$2.61

REDACTED

Date	Iroquois Waddington	Iroquois Z 2	Leidy	Millennium Pipeline	Niagara	TGP Z 5	Transco Zone 6 NY
11/1/2031	$2.84	$2.95	$2.64	$2.47	$3.20	$2.87	$3.23
12/1/2031	$3.08	$3.63	$2.68	$2.59	$3.18	$3.36	$4.26
1/1/2032	$4.42	$5.70	$2.65	$2.59	$3.26	$4.82	$5.12
2/1/2032	$3.42	$4.01	$2.67	$2.52	$3.23	$3.62	$4.32
3/1/2032	$2.89	$3.09	$2.65	$2.56	$3.25	$2.94	$3.45
4/1/2032	$2.59	$2.62	$2.22	$2.37	$3.04	$2.53	$2.79
5/1/2032	$2.79	$2.81	$2.23	$2.14	$2.97	$2.59	$2.64
6/1/2032	$2.75	$2.76	$2.24	$2.11	$2.97	$2.56	$2.65
7/1/2032	$2.81	$2.87	$2.26	$2.10	$2.98	$2.55	$2.74
8/1/2032	$2.96	$3.00	$2.28	$2.09	$2.99	$2.59	$2.74
9/1/2032	$2.84	$2.84	$2.29	$2.06	$3.10	$2.58	$2.71
10/1/2032	$2.81	$2.82	$2.32	$2.04	$3.19	$2.55	$2.75
11/1/2032	$2.92	$3.03	$2.67	$2.54	$3.34	$2.94	$3.31
12/1/2032	$3.16	$3.71	$2.71	$2.68	$3.32	$3.44	$4.40
1/1/2033	$4.62	$5.96	$2.90	$2.74	$3.47	$5.05	$5.36
2/1/2033	$3.73	$4.37	$2.85	$2.79	$3.44	$3.94	$4.72
3/1/2033	$2.90	$3.10	$2.62	$2.57	$3.31	$2.95	$3.46
4/1/2033	$2.52	$2.55	$2.24	$2.31	$3.08	$2.47	$2.73
5/1/2033	$2.70	$2.73	$2.14	$2.08	$2.99	$2.51	$2.57
6/1/2033	$2.67	$2.68	$2.04	$2.06	$3.00	$2.49	$2.58
7/1/2033	$2.73	$2.79	$2.17	$2.04	$3.01	$2.48	$2.66
8/1/2033	$2.86	$2.90	$2.15	$2.02	$3.01	$2.51	$2.65
9/1/2033	$2.75	$2.75	$2.06	$2.00	$3.13	$2.49	$2.63
10/1/2033	$2.72	$2.74	$2.17	$1.98	$3.21	$2.47	$2.67
11/1/2033	$2.87	$2.97	$2.60	$2.49	$3.38	$2.89	$3.26
12/1/2033	$3.09	$3.64	$2.65	$2.72	$3.36	$3.38	$4.45
1/1/2034	$4.77	$6.16	$3.04	$2.83	$3.68	$5.21	$5.51
2/1/2034	$3.89	$4.56	$3.04	$2.93	$3.65	$4.12	$4.91
3/1/2034	$2.96	$3.17	$2.61	$2.66	$3.45	$3.01	$3.57
4/1/2034	$2.56	$2.59	$2.07	$2.34	$3.22	$2.50	$2.76
5/1/2034	$2.81	$2.84	$2.08	$2.17	$3.14	$2.62	$2.67
6/1/2034	$2.78	$2.79	$2.10	$2.14	$3.15	$2.59	$2.69
7/1/2034	$2.83	$2.89	$2.12	$2.10	$3.15	$2.57	$2.74
8/1/2034	$2.97	$3.01	$2.14	$2.09	$3.16	$2.60	$2.75
9/1/2034	$2.87	$2.87	$2.16	$2.08	$3.28	$2.60	$2.73
10/1/2034	$2.81	$2.83	$2.17	$2.05	$3.36	$2.56	$2.76
11/1/2034	$3.04	$3.15	$2.60	$2.64	$3.58	$3.06	$3.44
12/1/2034	$3.32	$3.91	$2.91	$2.93	$3.55	$3.62	$4.74
1/1/2035	$4.67	$6.03	$2.89	$2.75	$3.56	$5.10	$5.38
2/1/2035	$3.79	$4.44	$2.90	$2.83	$3.53	$4.01	$4.77
3/1/2035	$2.91	$3.12	$2.31	$2.59	$3.51	$2.96	$3.49
4/1/2035	$2.61	$2.64	$2.18	$2.39	$3.29	$2.55	$2.81
5/1/2035	$2.82	$2.85	$2.19	$2.17	$3.21	$2.62	$2.68
6/1/2035	$2.79	$2.80	$2.22	$2.15	$3.22	$2.60	$2.70

REDACTED

Date	Iroquois Waddington	Iroquois Z 2	Leidy	Millennium Pipeline	Niagara	TGP Z 5	Transco Zone 6 NY
7/1/2035	$2.81	$2.87	$2.24	$2.10	$3.23	$2.55	$2.74
8/1/2035	$2.96	$3.00	$2.26	$2.09	$3.23	$2.60	$2.75
9/1/2035	$2.88	$2.88	$2.27	$2.09	$3.36	$2.61	$2.74
10/1/2035	$2.82	$2.84	$2.28	$2.06	$3.44	$2.57	$2.77
11/1/2035	$3.13	$3.25	$2.77	$2.73	$3.66	$3.16	$3.55
12/1/2035	$3.39	$3.99	$2.98	$3.03	$3.63	$3.70	$4.89
1/1/2036	$4.78	$6.17	$3.02	$2.87	$3.79	$5.22	$5.56
2/1/2036	$3.82	$4.48	$2.93	$2.90	$3.69	$4.04	$4.88
3/1/2036	$2.95	$3.16	$2.36	$2.65	$3.57	$3.00	$3.57
4/1/2036	$2.54	$2.57	$2.19	$2.32	$3.32	$2.48	$2.74
5/1/2036	$2.77	$2.79	$2.19	$2.13	$3.22	$2.57	$2.62
6/1/2036	$2.83	$2.83	$2.29	$2.18	$3.31	$2.63	$2.73
7/1/2036	$2.82	$2.87	$2.27	$2.10	$3.28	$2.55	$2.74
8/1/2036	$2.90	$2.94	$2.24	$2.06	$3.23	$2.55	$2.70
9/1/2036	$2.92	$2.92	$2.35	$2.12	$3.46	$2.64	$2.78
10/1/2036	$2.81	$2.83	$2.31	$2.04	$3.48	$2.55	$2.75
11/1/2036	$3.43	$3.56	$3.03	$3.00	$3.91	$3.45	$3.90
12/1/2036	$3.59	$4.22	$3.27	$3.23	$3.92	$3.91	$5.17
1/1/2037	$4.98	$6.42	$3.32	$3.07	$4.10	$5.44	$5.89
2/1/2037	$4.06	$4.76	$3.28	$3.16	$4.03	$4.30	$5.26
3/1/2037	$2.84	$3.04	$2.24	$2.52	$3.48	$2.88	$3.39
4/1/2037	$2.44	$2.46	$2.14	$2.23	$3.26	$2.38	$2.62
5/1/2037	$2.70	$2.73	$2.16	$2.08	$3.19	$2.52	$2.56
6/1/2037	$2.63	$2.64	$2.15	$2.03	$3.16	$2.45	$2.53
7/1/2037	$2.65	$2.70	$2.15	$1.98	$3.16	$2.40	$2.57
8/1/2037	$2.78	$2.82	$2.17	$1.97	$3.16	$2.44	$2.58
9/1/2037	$2.70	$2.70	$2.19	$1.96	$3.28	$2.45	$2.57
10/1/2037	$2.66	$2.68	$2.22	$1.94	$3.38	$2.42	$2.61
11/1/2037	$3.15	$3.27	$2.81	$2.75	$3.65	$3.17	$3.58
12/1/2037	$3.36	$3.96	$2.90	$3.03	$3.60	$3.67	$4.88
1/1/2038	$4.84	$6.24	$3.10	$2.97	$3.96	$5.29	$5.73
2/1/2038	$3.93	$4.60	$3.10	$3.08	$3.91	$4.16	$5.14
3/1/2038	$2.81	$3.01	$2.28	$2.50	$3.55	$2.86	$3.36
4/1/2038	$2.45	$2.48	$2.17	$2.24	$3.31	$2.39	$2.63
5/1/2038	$2.70	$2.73	$2.18	$2.08	$3.23	$2.51	$2.56
6/1/2038	$2.64	$2.65	$2.18	$2.03	$3.20	$2.46	$2.54
7/1/2038	$2.67	$2.72	$2.21	$1.99	$3.22	$2.42	$2.59
8/1/2038	$2.80	$2.84	$2.23	$1.98	$3.22	$2.45	$2.59
9/1/2038	$2.70	$2.71	$2.23	$1.96	$3.33	$2.45	$2.57
10/1/2038	$2.64	$2.66	$2.24	$1.93	$3.40	$2.40	$2.59
11/1/2038	$3.58	$3.72	$3.30	$3.14	$4.21	$3.61	$4.07
12/1/2038	$3.72	$4.37	$3.35	$3.39	$4.17	$4.06	$5.40
1/1/2039	$4.80	$6.19	$3.02	$2.96	$3.91	$5.24	$5.71
2/1/2039	$3.93	$4.61	$3.05	$3.08	$3.89	$4.16	$5.15

REDACTED

Date	Iroquois Waddington	Iroquois Z 2	Leidy	Millennium Pipeline	Niagara	TGP Z 5	Transco Zone 6 NY
3/1/2039	$2.81	$3.01	$2.31	$2.49	$3.57	$2.85	$3.36
4/1/2039	$2.48	$2.51	$2.20	$2.27	$3.35	$2.42	$2.67
5/1/2039	$2.71	$2.73	$2.18	$2.08	$3.23	$2.52	$2.56
6/1/2039	$2.66	$2.66	$2.19	$2.04	$3.23	$2.48	$2.56
7/1/2039	$2.66	$2.71	$2.22	$1.98	$3.22	$2.41	$2.58
8/1/2039	$2.81	$2.85	$2.26	$1.99	$3.24	$2.47	$2.61
9/1/2039	$2.75	$2.75	$2.27	$1.99	$3.37	$2.49	$2.60
10/1/2039	$2.68	$2.70	$2.28	$1.96	$3.44	$2.44	$2.63
11/1/2039	$3.42	$3.55	$3.10	$3.00	$3.98	$3.44	$3.89
12/1/2039	$3.59	$4.22	$3.17	$3.26	$3.96	$3.92	$5.22
1/1/2040	$4.89	$6.31	$3.12	$3.03	$4.03	$5.34	$5.83
2/1/2040	$3.97	$4.65	$3.14	$3.16	$4.03	$4.20	$5.26
3/1/2040	$2.86	$3.07	$2.33	$2.55	$3.59	$2.91	$3.43
4/1/2040	$2.50	$2.53	$2.22	$2.29	$3.37	$2.44	$2.70
5/1/2040	$2.78	$2.81	$2.24	$2.13	$3.30	$2.59	$2.63
6/1/2040	$2.78	$2.79	$2.28	$2.14	$3.34	$2.59	$2.68
7/1/2040	$2.78	$2.84	$2.32	$2.08	$3.34	$2.52	$2.71
8/1/2040	$2.89	$2.93	$2.29	$2.04	$3.30	$2.53	$2.68
9/1/2040	$2.82	$2.83	$2.31	$2.05	$3.43	$2.56	$2.69
10/1/2040	$2.74	$2.76	$2.30	$2.00	$3.51	$2.49	$2.70
11/1/2040	$3.57	$3.70	$3.06	$3.10	$3.98	$3.60	$4.08
12/1/2040	$3.55	$4.18	$3.08	$3.23	$3.91	$3.87	$5.23
1/1/2041	$4.55	$5.87	$3.08	$3.08	$4.03	$4.97	$5.96
2/1/2041	$3.96	$4.64	$3.08	$3.13	$4.01	$4.19	$5.28
3/1/2041	$2.88	$3.08	$2.39	$2.56	$3.66	$2.93	$3.44
4/1/2041	$2.54	$2.57	$2.26	$2.33	$3.46	$2.48	$2.74
5/1/2041	$2.89	$2.92	$2.33	$2.22	$3.43	$2.69	$2.73
6/1/2041	$2.85	$2.86	$2.34	$2.19	$3.43	$2.66	$2.74
7/1/2041	$2.81	$2.87	$2.33	$2.09	$3.39	$2.55	$2.73
8/1/2041	$2.91	$2.95	$2.31	$2.06	$3.35	$2.55	$2.70
9/1/2041	$2.88	$2.88	$2.35	$2.09	$3.52	$2.61	$2.74
10/1/2041	$2.81	$2.83	$2.36	$2.05	$3.60	$2.55	$2.76
11/1/2041	$3.67	$3.81	$3.20	$3.19	$4.15	$3.70	$4.18
12/1/2041	$3.65	$4.30	$3.20	$3.32	$4.03	$3.99	$5.36
1/1/2042	$4.50	$5.80	$3.13	$3.08	$4.08	$4.91	$5.96
2/1/2042	$3.95	$4.63	$3.13	$3.16	$4.02	$4.18	$5.31
3/1/2042	$2.80	$3.00	$2.35	$2.51	$3.62	$2.84	$3.35
4/1/2042	$2.58	$2.61	$2.24	$2.37	$3.45	$2.53	$2.80
5/1/2042	$2.84	$2.86	$2.24	$2.18	$3.35	$2.64	$2.69
6/1/2042	$2.83	$2.84	$2.29	$2.18	$3.38	$2.64	$2.73
7/1/2042	$2.78	$2.84	$2.30	$2.08	$3.34	$2.53	$2.71
8/1/2042	$2.93	$2.97	$2.32	$2.08	$3.34	$2.57	$2.73
9/1/2042	$2.85	$2.85	$2.31	$2.07	$3.46	$2.58	$2.72
10/1/2042	$2.75	$2.77	$2.27	$2.01	$3.49	$2.50	$2.71

REDACTED

Date	Iroquois Waddington	Iroquois Z 2	Leidy	Millennium Pipeline	Niagara	TGP Z 5	Transco Zone 6 NY
11/1/2042	$3.61	$3.74	$3.09	$3.14	$4.06	$3.63	$4.12
12/1/2042	$3.68	$4.33	$3.24	$3.35	$4.05	$4.01	$5.40
1/1/2043	$4.42	$5.70	$3.06	$3.01	$3.97	$4.83	$5.86
2/1/2043	$3.96	$4.64	$3.13	$3.17	$4.00	$4.19	$5.33
3/1/2043	$2.72	$2.91	$2.32	$2.43	$3.60	$2.76	$3.25
4/1/2043	$2.47	$2.50	$2.15	$2.27	$3.35	$2.42	$2.67
5/1/2043	$2.81	$2.83	$2.21	$2.16	$3.31	$2.61	$2.65
6/1/2043	$2.77	$2.78	$2.22	$2.13	$3.32	$2.58	$2.66
7/1/2043	$2.76	$2.82	$2.29	$2.06	$3.32	$2.51	$2.68
8/1/2043	$2.87	$2.91	$2.27	$2.02	$3.28	$2.51	$2.65
9/1/2043	$2.79	$2.79	$2.25	$2.02	$3.39	$2.53	$2.65
10/1/2043	$2.71	$2.72	$2.25	$1.98	$3.47	$2.46	$2.66
11/1/2043	$3.52	$3.66	$3.11	$3.08	$4.15	$3.55	$4.01
12/1/2043	$3.61	$4.24	$3.18	$3.25	$4.03	$3.94	$5.23
1/1/2044	$4.53	$5.84	$3.25	$3.11	$4.11	$4.95	$5.98
2/1/2044	$4.13	$4.83	$3.24	$3.23	$4.20	$4.37	$5.38
3/1/2044	$2.74	$2.93	$2.35	$2.44	$3.66	$2.78	$3.27
4/1/2044	$2.52	$2.55	$2.23	$2.31	$3.43	$2.47	$2.72
5/1/2044	$2.81	$2.83	$2.22	$2.16	$3.32	$2.61	$2.65
6/1/2044	$2.77	$2.78	$2.24	$2.13	$3.33	$2.58	$2.66
7/1/2044	$2.81	$2.87	$2.32	$2.09	$3.37	$2.55	$2.72
8/1/2044	$2.92	$2.95	$2.30	$2.06	$3.34	$2.56	$2.69
9/1/2044	$2.79	$2.79	$2.25	$2.02	$3.40	$2.53	$2.65
10/1/2044	$2.71	$2.73	$2.25	$1.98	$3.48	$2.46	$2.66
11/1/2044	$3.59	$3.73	$3.15	$3.12	$4.13	$3.62	$4.10
12/1/2044	$3.65	$4.29	$3.22	$3.30	$4.06	$3.98	$5.33
1/1/2045	$4.55	$5.87	$3.25	$3.12	$4.14	$4.97	$6.03
2/1/2045	$4.01	$4.70	$3.21	$3.21	$4.07	$4.25	$5.39
3/1/2045	$2.74	$2.94	$2.32	$2.45	$3.62	$2.79	$3.28
4/1/2045	$2.54	$2.57	$2.25	$2.34	$3.43	$2.48	$2.76
5/1/2045	$2.87	$2.90	$2.28	$2.21	$3.36	$2.67	$2.72
6/1/2045	$2.80	$2.81	$2.26	$2.15	$3.33	$2.61	$2.69
7/1/2045	$2.84	$2.89	$2.35	$2.11	$3.38	$2.57	$2.75
8/1/2045	$2.94	$2.98	$2.33	$2.08	$3.34	$2.58	$2.72
9/1/2045	$2.85	$2.86	$2.31	$2.07	$3.44	$2.58	$2.71
10/1/2045	$2.77	$2.79	$2.31	$2.02	$3.52	$2.52	$2.72
11/1/2045	$3.60	$3.74	$3.08	$3.13	$4.16	$3.63	$4.11
12/1/2045	$3.64	$4.28	$3.18	$3.31	$4.09	$3.97	$5.34
1/1/2046	$4.52	$5.83	$3.19	$3.10	$4.17	$4.94	$6.00
2/1/2046	$4.06	$4.75	$3.24	$3.25	$4.19	$4.29	$5.44
3/1/2046	$2.74	$2.94	$2.35	$2.43	$3.62	$2.79	$3.27
4/1/2046	$2.52	$2.55	$2.27	$2.33	$3.40	$2.46	$2.73
5/1/2046	$2.90	$2.93	$2.33	$2.23	$3.37	$2.70	$2.74
6/1/2046	$2.86	$2.87	$2.33	$2.20	$3.38	$2.67	$2.75

REDACTED

Date	Iroquois Waddington	Iroquois Z 2	Leidy	Millennium Pipeline	Niagara	TGP Z 5	Transco Zone 6 NY
7/1/2046	$2.82	$2.87	$2.33	$2.10	$3.34	$2.56	$2.73
8/1/2046	$2.97	$3.01	$2.35	$2.10	$3.35	$2.61	$2.74
9/1/2046	$2.83	$2.84	$2.29	$2.06	$3.40	$2.57	$2.69
10/1/2046	$2.80	$2.82	$2.35	$2.05	$3.53	$2.54	$2.75
11/1/2046	$3.65	$3.78	$3.15	$3.17	$4.23	$3.67	$4.16
12/1/2046	$3.64	$4.29	$3.22	$3.30	$4.16	$3.97	$5.33
1/1/2047	$4.54	$5.85	$3.21	$3.11	$4.21	$4.95	$6.02
2/1/2047	$4.01	$4.70	$3.19	$3.19	$4.15	$4.24	$5.36
3/1/2047	$2.76	$2.95	$2.34	$2.45	$3.55	$2.80	$3.30
4/1/2047	$2.54	$2.57	$2.25	$2.35	$3.34	$2.48	$2.76
5/1/2047	$2.82	$2.85	$2.25	$2.17	$3.23	$2.63	$2.68
6/1/2047	$2.79	$2.80	$2.26	$2.14	$3.24	$2.60	$2.68
7/1/2047	$2.78	$2.83	$2.30	$2.07	$3.24	$2.52	$2.70
8/1/2047	$2.88	$2.92	$2.27	$2.03	$3.19	$2.52	$2.66
9/1/2047	$2.79	$2.79	$2.27	$2.02	$3.29	$2.53	$2.65
10/1/2047	$2.71	$2.73	$2.27	$1.99	$3.37	$2.47	$2.67
11/1/2047	$3.66	$3.79	$3.19	$3.18	$4.27	$3.68	$4.17
12/1/2047	$3.61	$4.24	$3.21	$3.27	$4.14	$3.93	$5.29
1/1/2048	$4.57	$5.89	$3.27	$3.12	$4.27	$4.99	$6.02
2/1/2048	$4.12	$4.83	$3.42	$3.31	$4.52	$4.36	$5.53
3/1/2048	$2.77	$2.97	$2.41	$2.46	$3.55	$2.82	$3.32
4/1/2048	$2.61	$2.64	$2.33	$2.41	$3.37	$2.55	$2.83
5/1/2048	$2.89	$2.92	$2.33	$2.23	$3.27	$2.69	$2.74
6/1/2048	$2.89	$2.90	$2.38	$2.22	$3.31	$2.70	$2.78
7/1/2048	$2.89	$2.95	$2.42	$2.15	$3.32	$2.62	$2.80
8/1/2048	$2.95	$2.99	$2.36	$2.08	$3.23	$2.59	$2.73
9/1/2048	$2.90	$2.90	$2.39	$2.11	$3.37	$2.63	$2.76
10/1/2048	$2.78	$2.79	$2.36	$2.03	$3.40	$2.52	$2.73
11/1/2048	$3.77	$3.91	$3.31	$3.28	$4.50	$3.79	$4.29
12/1/2048	$3.73	$4.39	$3.40	$3.41	$4.48	$4.07	$5.47
1/1/2049	$4.66	$6.01	$3.40	$3.20	$4.68	$5.09	$6.15
2/1/2049	$4.07	$4.77	$3.35	$3.26	$4.58	$4.31	$5.47
3/1/2049	$2.83	$3.03	$2.52	$2.52	$3.78	$2.88	$3.38
4/1/2049	$2.59	$2.62	$2.37	$2.39	$3.51	$2.53	$2.80
5/1/2049	$2.96	$2.98	$2.43	$2.27	$3.47	$2.75	$2.80
6/1/2049	$2.92	$2.93	$2.44	$2.24	$3.48	$2.72	$2.80
7/1/2049	$2.91	$2.97	$2.47	$2.17	$3.48	$2.64	$2.82
8/1/2049	$2.98	$3.02	$2.40	$2.10	$3.40	$2.61	$2.75
9/1/2049	$2.93	$2.93	$2.44	$2.12	$3.55	$2.65	$2.78
10/1/2049	$2.84	$2.86	$2.45	$2.08	$3.63	$2.58	$2.79
11/1/2049	$3.81	$3.95	$3.38	$3.32	$4.64	$3.84	$4.34
12/1/2049	$3.74	$4.40	$3.41	$3.42	$4.56	$4.08	$5.49
1/1/2050	$4.65	$5.99	$3.41	$3.21	$4.79	$5.07	$6.17
2/1/2050	$4.13	$4.84	$3.40	$3.33	$4.76	$4.37	$5.56

REDACTED

Date	Iroquois Waddington	Iroquois Z 2	Leidy	Millennium Pipeline	Niagara	TGP Z 5	Transco Zone 6 NY
3/1/2050	$2.82	$3.02	$2.54	$2.50	$3.82	$2.86	$3.36
4/1/2050	$2.57	$2.60	$2.38	$2.36	$3.54	$2.51	$2.77
5/1/2050	$2.92	$2.95	$2.45	$2.25	$3.51	$2.72	$2.77
6/1/2050	$2.85	$2.86	$2.42	$2.19	$3.48	$2.66	$2.74
7/1/2050	$2.88	$2.94	$2.48	$2.14	$3.52	$2.62	$2.79
8/1/2050	$2.95	$2.99	$2.41	$2.08	$3.44	$2.58	$2.72
9/1/2050	$2.89	$2.89	$2.44	$2.10	$3.58	$2.62	$2.74
10/1/2050	$2.77	$2.79	$2.42	$2.03	$3.62	$2.52	$2.72
11/1/2050	$3.77	$3.91	$3.37	$3.30	$4.68	$3.80	$4.31
12/1/2050	$3.77	$4.43	$3.44	$3.44	$4.65	$4.11	$5.52

Table Appendix A-1. Natural Gas Prices Projection 2025-2050 (2021$/MMBtu)

A.2: Fuel Oil Prices Projection

Table Appendix A-2. Fuel Oil Prices Projection 2025-2050

Year	Distillate Oil Price (2021 $/MMBtu)	Residual Oil Price (2021 $/MMBtu)
2025	$15.89	$10.00
2026	$15.90	$10.01
2027	$16.32	$10.27
2028	$16.50	$10.39
2029	$16.98	$10.69
2030	$17.41	$10.96
2031	$17.71	$11.15
2032	$17.98	$11.32
2033	$18.20	$11.46
2034	$18.23	$11.48
2035	$18.20	$11.46
2036	$17.98	$11.32
2037	$18.00	$11.33
2038	$18.04	$11.35
2039	$17.82	$11.22
2040	$17.61	$11.09
2041	$17.39	$10.95
2042	$17.18	$10.81
2043	$17.02	$10.71
2044	$16.90	$10.64
2045	$16.83	$10.60
2046	$16.75	$10.55
2047	$16.48	$10.37

REDACTED

Year	Distillate Oil Price (2021 $/MMBtu)	Residual Oil Price (2021 $/MMBtu)
2048	$15.98	$10.06
2049	$15.56	$9.79
2050	$15.32	$9.64