Long-Term Contract for Offshore Wind Energy from Revolution Wind 400 MW Project - Quantitative Evaluation Report

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Submitted to:
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1. Summary and Overview

This report summarizes the analyses Tabors Caramanis Rudkevich ("TCR") prepared for The Narragansett Electric Company d/b/a National Grid ("Narragansett" or "Company") to evaluate the costs and benefits of the Revolution Wind 400 MW ("RW 400 MW") project and the results of that evaluation.

In May 2018 Narragansett began discussions with the Office of Energy Resources (OER) and the Division of Public Utilities and Carriers (Division) regarding the results from the Massachusetts electric distribution companies ("EDCs") Request for Proposals (RFP) to acquire Offshore Wind Energy Generation in order to comply with Section 83C of the Massachusetts Green Communities Act. Later that month the Massachusetts 83C Evaluation Team chose the Vineyard Wind 800 MW project, the highest ranked project. Narragansett chose the Revolution Wind 400 MW project, the next highest ranked generator lead line project after the Vineyard bids, for further evaluation based upon Rhode Island criteria. Narragansett retained TCR to calculate the quantitative costs of the Revolution Wind 400 MW project.[1]

Narragansett reviewed and evaluated the Revolution Wind 400 MW project using the process described in the testimony it has sponsored in this proceeding. As part of that process, TCR evaluated the costs and benefits of the Revolution Wind 400 MW project over the period 2021 through 2045 as a component of a portfolio consisting of it, the Vineyard Wind 800 MW project and a Revolution Wind 200 MW project selected by Connecticut. TCR evaluated the costs and benefits of the Revolution Wind 400 MW project using inputs from its bid and proposed power purchase agreement as well as results from modeling the operation of the New England and New York energy market under two future scenarios – a Proposal Case assuming the 1,400 MW portfolio of resources are developed and a Base Case assuming none of those portfolio resources are developed.

Attachment 1 presents the summary results from the Rhode Island quantitative evaluation in 2018 net present value (NPV) $/MWh.

Attachment 2 presents the summary results from the Rhode Island quantitative evaluation in absolute 2018 NPV $ according to the format for the Rhode Island Benefit Cost Test under the Docket 4600 framework.

Attachment 3 summarizes the key features of the Base Case used in the quantitative evaluation of the Proposal Case, i.e. the portfolio of the Revolution Wind 400 MW project, the Vineyard Wind 800 MW project and the Revolution Wind 200 MW project.

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[1] TCR as consultant to the Massachusetts 83C Evaluation Team, had evaluated the quantitative costs and benefits of the proposals received in response to the Massachusetts 83C RFP. The TCR report describing that quantitative evaluation was filed as Joint Exhibit JU-4 in Massachusetts Department of Public Utility Dockets 18-76, 18-77 and 18-78.

2. Evaluation of Costs and Benefits

TCR evaluated three categories of quantitative costs and benefits associated with the Proposal Case - Direct Contract Costs and Benefits ("Direct Costs and Benefits"), Indirect Benefits and Other 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. Attachment 1 presents the summary results from the Rhode Island quantitative evaluation in 2018 net present value (NPV) $/MWh. Attachment 2 presents the summary results from the Rhode Island quantitative evaluation in absolute 2018 NPV $ according to the format for the Rhode Island Benefit Cost Test under the Docket 4600 framework.

TCR began by developing the value of each category of costs and benefits, referred to as metrics, of the Proposal Case in each year of the evaluation period. Next TCR calculated the present value for each metric. Finally, it calculated the levelized unit value ($/MWh) of each metric as the present value divided by the present value of the annual energy from the project over the term of its contract. TCR calculated these values in 2018 constant dollars (2018$) as well as in nominal dollars.

Direct Costs and Benefits

TCR calculated the Total Net Direct Benefit (Cost) of the RW 400 MW project as the Direct Benefits from the project minus the Direct Costs of the project. The calculation uses the following metrics:

i. Direct Cost of Energy. This cost is calculated for each year of the proposed contract by multiplying the RW 400 MW project price for energy in each year by the quantity of energy from the project in that year.[2]

ii. Direct Cost of Renewable Energy Standard ("RES") Class 1 eligible Renewable Energy Credits ("RECs"). This cost is calculated for each year of the proposed contract by multiplying the RW 400 MW project price for RECs in each year by the quantity of RECs from the project in that year.

iii. Direct Benefit of Energy. This benefit is the market value of energy deliveries from the Project over the proposed contract term, based upon the forecast market energy prices at the delivery point with the project in service, i.e. under the Proposal Case.

iv. Direct Benefit of RECs. This benefit is the cost Narragansett will avoid by using RECs from the project to meet its RES requirements, rather than buying those RECs at market prices under the Base Case, plus the market value Narragansett would receive by selling RECs from the project that are surplus to its RES requirements in any given year at the forecasted REC price under the Proposal Case.

[2] This cost includes the cost of transmission between the generating units and interconnection with the ISO-New England ("ISO-NE") transmission system, since the RW 400 MW bid included those costs in its energy prices.

Indirect Benefits

TCR calculated the Total Indirect Benefit of the Proposal Case using the following metrics:

i. Indirect Energy Price Benefits. These benefits are the savings to Narragansett retail customers resulting from reductions in the supply costs Narragansett incurs to buy electric energy at wholesale market prices due to reductions in Locational Marginal Prices ("LMP") in Rhode Island under the Proposal Case relative to the Base Case.

ii. Indirect REC Price Benefits. These benefits are the savings to Narragansett retail customers resulting from reductions in the REC supply costs Narragansett incurs to acquire Class 1 RECs at market prices due to reductions in REC market prices under the Proposal Case relative to the Base Case.

Net Benefit (Cost)

The Net Benefit (Cost) of the Proposal Case is the sum of the Direct Benefits minus the sum of the Direct Costs plus the sum of the Indirect Benefits.

Other Benefits

TCR calculated six other benefits of the Proposal Case:

i. Non-embedded value of CO2 Reduction. This benefit is the value of the reduction in GHG emissions associated with electricity consumption in Rhode Island and ISO-NE neighboring states under the Proposal Case relative to the Base case. It is equal to the portion of the reduction in GHG emissions each year attributable to the Revolution Wind 400 MW project multiplied by the difference between the marginal abatement cost of carbon from *Avoided Energy Supply Components in New England*: *2018 Report*[3](“AESC 2018”) and the projected Regional Greenhouse Gas Initiative (“RGGI”) allowance price for that year.

ii. Non-embedded value of NOx Reduction. This benefit is the value of the reduction in NOx emissions associated with electricity consumption in Rhode Island and ISO-NE neighboring states under the Proposal Case relative to the Base case. It is equal to the portion of the reduction in NOx emissions each year attributable to the Revolution Wind 400 MW project multiplied by the non-embedded cost of NOx from AESC 2018 for that year.

iii. Increase in Project Power Purchase agreement (“PPA” market value from year with extreme winter fuel prices. This benefit is the increase in market value of energy from the Project, relative to a normal year, in a year with extreme winter fuel prices. The calculation of this benefit assumes the year with extreme fuel prices occurs once every fifteen years.

iv. Natural gas price benefits. These benefits are the savings to National Grid retail customers resulting from reductions in the supply costs National Grid incurs to buy natural gas at wholesale market prices in gas production areas and in New England under the Proposal Case relative to the Base Case. The market prices for gas in those locations are lower under the Proposal Case

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[3] Chang, Max et al. *Avoided Energy Supply Components in New England*: *2018 Report.* Synapse Energy Economics. June 2018 release.

relative to the Base Case due to the reduction in the quantity of gas required for electric generation in New England under the Proposal Case relative to the Base Case.

v. Non-embedded value of CO2 Reduction attributable to Rhode Island. This is the value of reduction in GHG emissions associated with electricity consumption in Rhode Island under the Proposal Case relative to the Base Case. It is equal to the reduction in GHG emissions each year attributable to Rhode Island multiplied by the difference between the marginal abatement cost of carbon from AESC 2018 and projected RGGI price for that year. The GHG emissions attributed to Rhode Island are calculated using a 'consumption-based' methodology adopted by the Rhode Island Executive Climate Change Coordinating Council ("RI-EC4") in the *Rhode Island Greenhouse Gas Emissions Reduction Plan*[4] ("EC4 Report"). This methodology pro-rates the reduction in GHG emissions each year by Rhode Island's fraction of New England wide energy consumption in that year.

vi. Non-embedded value of NOx Reduction attributable to Rhode Island. This benefit is the value of the reduction in NOx emissions associated with electricity consumption in Rhode Island under the Proposal Case relative to the Base case. It is equal to the reduction in NOx emissions each year attributable to Rhode Island multiplied by the non-embedded cost of NOx from AESC 2018 for that year. The NOx emissions attributed to Rhode Island are calculated using a 'consumption-based' methodology adopted by the RI-EC4 in the EC4 Report. This methodology pro-rates the reduction in NOx emissions each year by Rhode Island's fraction of New England wide energy consumption in that year.

Quantitative Workbook

TCR developed the values of these metrics in a Proposal Case quantitative workbook which drew its inputs from the RW 400 MW bid and negotiated PPA prices and from outputs of ENELYTIX modeling of the Proposal Case and the Base Case. Section 3 describes TCR's ENELYTIX modeling of the Base Case and Proposal Case. Section 4 describes TCR's quantitative evaluation workbook for the Proposal Case.

3. Market Simulations- Base Case and Proposal Case

TCR obtained many of the inputs it required to calculate the various costs and benefits of the Proposal Case from the outputs of its simulation modeling of the electricity market in New England under the Base Case and under the Proposal Case respectively. This section describes the major input assumptions TCR used in its modeling of the Base Case and the Proposal Case as well as the ENELYTIX platform used for that modeling.

A. Base Case and Proposal Case

The Base Case provides a "but for" or "counterfactual" projection of the costs of electric energy, RECs, and carbon emissions associated with Rhode Island electricity consumption under a future in which

[4] *Rhode Island Greenhouse Gas Emissions Reduction Plan, RI* EC4, December 2016

neither Rhode Island nor Massachusetts nor Connecticut acquire wind energy from Revolution Wind or Vineyard Wind projects under long-term contracts.[5] Attachment 3 provides key results from the ENELYTIX modeling of the Base Case.

The Proposal Case provides a projection of those costs under a future in which Rhode Island acquires energy from the Revolution Wind 400 MW project under a twenty year power purchase agreement ("PPA") starting January 2024 and Massachusetts and Connecticut acquire energy from the Vineyard Wind 800 MW project and the Revolution Wind 200 MW project respectively.

B. ENELYTIX Simulation Model

TCR used the ENELYTIX computer simulation software tool to simulate the operation of the New England wholesale markets for energy and ancillary services, forward capacity and RECs under the Base Case and for 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 such as capacity additions and retirements, energy generation by source, carbon emissions and natural gas burn. TCR conducted a separate ENELYTIX computer run for the Base Case and for 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[6]

The Capacity Expansion module determines an optimal electric system expansion in New England over a long-term planning horizon. Its 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 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. 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 RES or equivalent renewable portfolio standard ("RPS") requirements, Massachusetts Clean Energy Standard requirements, state specific RES / RPS resource eligibility, limitations on REC banking and borrowing, and alternative compliance payment ("ACP") prices.

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 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.

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5 The Base Case is not a plan for the Rhode Island electric sector and should not be viewed as such. TCR used the results from the Base Case as a common reference point against which to measure the various costs and benefits of the Proposal Case.

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

The two modules use the Power System Optimizer (PSO) market simulator developed by Polaris Systems Optimization, Inc.[7] In addition the two modules rely on data obtained from ISO-NE, including the economic and operational characteristics of ISO-NE's existing generating units, representation of the electric transmission system, and projection of future electricity demand.

C. Major Input Assumptions Used to Model Base Case and Proposal Case

This subsection summarizes each of the major categories of input assumptions TCR used in modeling ISO-NE.

TCR used ten major categories of input assumptions to model the Base Case and the Proposal Case in ENELYTIX. They were Generating Unit Capacity Additions, Transmission, Load Forecast, Installed Capacity Requirements, RES / RPS Requirements, Massachusetts Clean Energy Standard ("CES") and cap on Carbon Emissions, Emission Allowance Prices, Fuel Prices, Generating Unit Operational Characteristics and Generating Unit Retirements. Of these ten categories, Generating Unit Capacity Additions was the only category with a few differences in input assumption between the Base Case and Proposal Case.

Generating Unit Capacity Additions (Existing / Scheduled and Optional). This category consists of two groups of assumptions.

The first group of assumptions is existing / scheduled additions. These are specific generating resources input to ENELYTIX as being in-service during the evaluation period. The only difference in assumptions for existing / scheduled capacity additions between the Base Case and the Proposal Case is the portfolio of Revolution Wind 400 MW, Vineyard Wind 800 MW and Revolution Wind 200 MW. The Base Case does not include that portfolio of projects; the Proposal Case does include that portfolio. The remaining assumptions for existing and scheduled generating unit capacity addition assumptions are common to the Base Case and the Proposal Case. In addition, those remaining assumptions are the same as in the Massachusetts 83C Base Case and Proposal Cases except for updates to reflect:

- the 2018 ISO New England Forecast Report of Capacity, Energy, Loads, and Transmission (CELT Report);
- the ISO New England interconnection queue as of October 01,2018 that were either under construction or had major interconnection studies completed and cleared Forward Capacity Auction ("FCA") 12;
- Distributed photovoltaic (PV) capacity at levels in the ISO-NE's Final 2018 PV Forecast through 2027[8]; and
- 53.6 MW of Fuel Cell and Biomass generation from the Connecticut 2018 Clean energy procurement

[7] www.psopt.com.

[8] ISO New England Final 2018 PV Forecast, March 19,2018.

The second group of assumptions related to capacity additions is the set of generic generating resources from which ENELYTIX has the option to choose to add during the study horizon, as determined by its internal calculations. These assumptions are common to the Base Case and to the Proposal Case. ENELYTIX evaluated the economics of adding capacity from generic renewable resources, fossil fuel resources and advanced nuclear resources under the assumption that they would be developed and financed on a merchant basis, i.e. without long-term purchase power agreements.

Transmission. ENELYTIX provides a detailed representation of the transmission topology and electric characteristics of transmission facilities within ISO-NE and the NYISO. The transmission topology and electric characteristics of transmission facilities used for the Base Case and the Proposal Case are the same as for the Massachusetts 83C Base Case and Proposal Cases except the point of interconnection for 83C tranches 3 and 4 is changed from aggregate SEMA/RI to Brayton Point.

The remaining transmission assumptions are also common to the Massachusetts 83C Base and Proposal Cases with the ISO-NE transmission system based on the 2020 SUMMER Peak case and the NYISO system based on the 2017 Market Monitoring Working Group power flow case.

Load Forecast. The load forecast inputs to ENELYTIX are annual energy and peak load before the impacts of reductions due to behind the meter PV (BTM PV or BMPV) and passive demand response ("PDR") as well as after reductions from those resources. The before reduction load forecast is referred to as Gross, and the after reduction forecast is referred to as Gross-PV-PDR or Net Energy for Load ("NEL"). TCR developed the forecasts of Gross load and of load served by PV through 2027 directly from the 2018 CELT Report and from 2028 onward by extrapolations. TCR developed its forecast of energy from PDR through 2027 by adjusting the CELT forecast of PDR capacity for PDR that cleared FCA 10, 11, 12 and applying implicit PDR load factors from the 2018 CELT. It derived the forecast of energy from PDR for 2028 onward using the forecast of NEL in New England from the Energy Information Administration ("EIA") Annual Energy Outlook 2018 ("AEO 2018") and TCR forecasts for Gross load and PV loads in those years.

In order to simulate the ISO New England market on an hourly basis, TCR developed hourly load shapes 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. The Base Case and Proposal Case assumptions are based upon results of FCA-12 and the load forecast.

RES / RPS Requirements. ENELYTIX models the Class 1 RES / RPS requirements of each New England state with a requirement[9] The RES / RPS requirement input to ENELYTIX for each state equals the forecast load of Load Serving Entities (LSEs) obligated to comply with that state's RES / RPS multiplied by that state's annual Class 1 RES / RPS percentage target. The forecast load of LSEs is the forecast Gross-

[9] Vermont does not have an equivalent Class 1 RPS requirement.

PV-PDR load for each state reduced by the load exempt from the RES / RPS in that state. Additional RES / RPS inputs to ENELYTIX are state-specific resource eligibility, limitations on certificate banking and borrowing, and ACP prices. These RES / RPS assumptions are common to the Massachusetts 83C Base and Proposal Cases except for updates to Massachusetts and Connecticut requirements, the Connecticut ACP revised biomass RPS eligibility in CT and inclusion of RECs from behind-the-meter biomass units in Maine.

Massachusetts CES and cap on Carbon Emissions. ENELYTIX models the cap on carbon emissions from electric generating units (EGU) located in Massachusetts per regulation 310 CMR 7.74 as well as the CES per regulation 310 CMR 7.75. These assumptions are the same as for the Massachusetts 83C Base and Proposal Cases.

Emission Allowance Prices. TCR developed the assumption of CO2 allowance prices based upon its review of the Regional Greenhouse Gas Initiative (RGGI) projections from its 2017 Model Rule Policy Scenario Overview dated September 25, 2017. The allowance prices assumed for CO2 emissions follow a trajectory of RGGI's "2017 RGGI Model Rule Policy Scenario (No National Program)" from 2019 through 2022, rising smoothly to reach the level of RGGI's "2017 RGGI Model Rule Policy Scenario - (National Program, High Emissions Sensitivity Case)" scenario by 2030, and continuing along the same curve to 2045. The allowance price assumptions for NOx and SO_2 emissions are zero because no New England state has emission limits under the Federal Cross State Air Pollution Rule (CSAPR), the source of those allowance prices.

Generating Unit Operational Characteristics. TCR develops assumptions for the key physical and cost operating parameters for each type of generating unit and resource that ENELYTIX models. These include thermal units, nuclear units, hydro, pumped storage hydro, wind and solar PV. These assumptions are the same as for the Massachusetts 83C Base and Proposal Cases except all prices and costs, e.g., capital costs, fixed operations and maintenance, variable operation and maintenance are updated to 2018$ and Mystic units 8 and 9, after their Reliability Must Run agreements expire, will operate on gas priced based on liquefied natural gas subject to their economic viability.

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 projections of Henry Hub prices plus projections of basis differential to each hub from the Henry Hub. The projection of annual Henry Hub prices is a blend of forward prices as of October 16, 2018 and the Reference Case forecast from the Energy Information Administration (EIA) Annual Energy Outlook 2018 (AEO 2018). The projection of monthly basis through December 2026 is drawn from forward markets for those products as of October 2018. The projection from January 2027 onward assumes basis will remain relatively constant in 2018$. The projections of distillate and residual to electric generators in New England are drawn from AEO 2018.

Generating Unit Retirements. This category, like generating unit additions, consists of two groups of assumptions. First, there are the specific generating capacity units that are input to ENELYTIX as retiring prior to, or during, the evaluation period. These are the actual generating units that have retired prior to the beginning of the evaluation period (January 2021) plus the ISO-NE approved scheduled retirements as of August 17, 2018. Second, there are the economic assumptions ENELYTIX uses to determine whether to simulate retirement of an existing generating unit during the evaluation period. ENELYTIX determines whether it is cost efficient within the simulation to keep the existing unit online or retire and replace it with more efficient generator or with the resource needed to meet environmental constraints.

4. Proposal Evaluation- Quantitative Workbook

TCR used a quantitative workbook to calculate the costs and benefits of the Proposal Case. The Quantitative Workbook is an EXCEL workbook consisting of the following worksheets:

- Rhode Island Benefit Cost Test results, in nominal $ and 2018$ respectively,
- Summary worksheets, in nominal $ and 2018$ respectively,
- Proposal Quant Metrics worksheet, in 2018$ and nominal$
- worksheets for calculations of RECs, GHG, NOX and natural gas price impacts by year
- worksheets providing key summary outputs from ENELYTIX modeling of the Proposal Case and the Base Case,
- a worksheet reporting RW 400 MW PPA pricing for energy and RECs, and
- 22 worksheets reporting detailed results from ENELYTIX modeling of the Proposal Case.

This section describes the worksheets for calculations of RECs, GHG, NOX and natural gas price impacts by year and the Proposal Metrics worksheet.

A. Proposal Quant Metrics Worksheet

The Proposal Quant Metrics worksheet develops values for each of the metrics used to calculate Direct Costs, Direct Benefits, Indirect Benefits and Other Benefits. It develops values in 2018$ for each year of the 2021 to 2045 evaluation period as well as the present value of that stream of annual values. It then develops the corresponding values in nominal $.

The Proposal Quant Metrics worksheet develops these annual values from the following major inputs:

- Prices for energy and RECs from the proposed contract for energy and RECs from the Revolution Wind 400 MW project
- Results from ENELYTIX modeling of the Proposal Case
- Results from ENELYTIX modeling of the Base Case
- Results from the worksheets for RECs, GHG, NOX and natural gas price impacts by year

B. RECs worksheet

The RECs worksheet begins with projections of the quantity of RECs that will be required to satisfy the Rhode Island RES each year, the quantity of RECs that Narragansett will acquire from its existing contracts for RECs and the quantity of REC the Revolution Wind 400 MW project will produce each year. The worksheet then calculates the following outputs by year:

1. RECs from Project (MWh) used towards Rhode Island RES contract gap. This equals the annual quantity of RECs that will be required to meet the Rhode Island RES minus the quantity that Narragansett will acquire from its existing contracts for RECs.
2. Residual quantity of RECs (MWh) purchased at market prices to comply with Rhode Island RES requirements. This equals the annual quantity that will be required minus the quantity that will be acquired from existing contracts for RECs minus the quantity from the Revolution Wind 400 MW project that Narragansett will use to meet the Rhode Island RES contract gap.
3. RECs from Project (MWh) sold out of state. This equals the annual quantity that the Revolution Wind 400 MW project will produce minus the quantity of RECs from that project that Narragansett will use to meet the Rhode Island RES contract gap.

C. GHG Worksheet

The GHG Worksheet begins with ENELYTIX projections of carbon dioxide emissions associated with electricity use in New England by year under the Base Case and under the Proposal Case respectively. It then calculates the reduction in carbon emissions (metric tons) by year under the Proposal Case relative to the Base Case. The workbook then calculates the Rhode Island fraction of New England demand (%) by year and multiplies it with the calculated reduction in carbon emissions, to obtain the reduction in carbon emissions attributable to Rhode Island (metric tons) by year. Projections for in-state demand for New England are obtained from ENELYTIX.

The worksheet also calculates the non-embedded unit value of a reduction in carbon dioxide each year as the difference between the marginal abatement cost of carbon from AESC 2018 of $100 (2018$)/Metric ton and the projected Regional Greenhouse Gas Initiative (“RGGI”) allowance price each year in 2018$/Metric ton.

D. NOx Worksheet

The NOx Worksheet begins with ENELYTIX projections of NOx emissions associated with electricity use in New England by year under the Base Case and under the Proposal Case. It then calculates the reduction in NOX emissions (metric tons) by year under the Proposal Case relative to the Base Case. The workbook then uses the Rhode Island fraction of New England demand calculated in the GHG worksheet and multiplies it with the calculated reduction in NOX emissions, to obtain the reduction in NOX emissions attributable to Rhode Island (metric tons) by year.

The worksheet also calculates the non-embedded unit value of a reduction in NOx each year as $13,178 (2018$)/Metric ton from AESC 2018.

E. Natural Gas Price Impact Worksheets

One major impact of the Proposal Case is a reduction in annual gas use for electric generation in New England relative to the Base Case. It is generally accepted that a significant reduction in gas use in New England, whether due to greater use of renewables or an increase in the efficiency of use, will cause reductions in the market prices of gas in production areas as well as in New England. AESC 2018 refers to those price reductions as DRIPE. It estimates their coefficients to be as follows:

> Production area prices (gas commodity DRIPE) - a reduction of 1 MMBtu in annual natural gas demand would reduce Henry Hub prices by $0.15 x 10-8/MMBtu[10].
>
> Natural gas basis DRIPE – a reduction of 1,000,000 MMBtu/day would reduce New England basis in summer months (March through October) by $1.09/MMBtu and in winter months (November through April) by $4.98/MMBtu. (This New England basis is the difference between market prices in New England and market prices in at the Henry Hub)[11].

The *Portfolio Gas Price Impact* sheet calculates the reduction in gas production area and winter basis prices each year by applying those AESC 2018 coefficients to the relevant reductions in gas use under the Proposal Case.

The *Portfolio RI gas cost impact* sheet calculates the resulting reductions in the gas supply costs of NGRID gas distribution service customers each year by applying the price reductions to the relevant quantities of gas NGRID purchases to serve its Rhode Island customers.

[10] Chang, Max et al. *Avoided Energy Supply Components in New England*: *2018 Report.* Synapse Energy Economics. June 2018 release. Page 176.
[11] *Ibid*., Page 181, Table 80.

REDACTED

Attachment 1

Quantitative Results, 2018$ / MWh

REDACTED

A - 2

Summary Workbook

2018$

Proposal Case - Portfolio RW400 + VW800 + RW200

Project - RW 400 MW Levelized 20 Year PPA

Evaluation Type	Standard
Workbook Date	1/3/2019
Proposal Details (From CPPD)	
Resource Type	Off Shore Wind
Contract Maximum Amount (MW)	400
Project Net Capacity Factor (%)	0.466
Proposed Annual Delivery (MWh)	1633252.216
Storage Included	No
PPA Start Date	1/1/2024
PPA End Date	12/31/2043
Term (years)	20
ISO-NE Load Zone	4005 .Z.RHODEISLAND
Quantitative Metric Summary	**2018$/MWh**
D.1 Direct Metrics	
Direct Cost of Project Energy	$ 54.92
Direct Cost of Project RECs	$ 20.23
Sub total - Direct Cost of Project Energy + RECs	**$ 75.16**
Market Value of Energy from Project	$ 51.18
Value of Project RECs used for RPS (Qty of RECs * Base Case REC price avoided)	$ 16.30
Value of Project RECs sold out of state (Qty of RECs * Proposal Case REC price)	$ 7.94
Direct Benefit of Project Energy + RECs	**$ 75.42**
Total Net Direct Benefit (Cost) of Project	$ 0.26
D.2 Indirect Metrics [1]	
RI Energy Market Price Change Impact = Change in Annual Energy Market Value to EDC Load / Proposal Energy	$ 4.90
Class 1 REC Market Price Change Impact = Quantity of RECs acquired at market price for EDC distribution load * Change in REC Market Price / Proposal Energy	$ -
Total Net Indirect Benefit (Cost)	$ 4.90
D.3 Total of Direct and Indirect Metrics	
Total Unit Net Benefit (Cost)	$ 5.16

Net Benefit (Cost) : Absolute value	$ 91,634,166

Notes

1 Indirect economic benefits to RI from the Proposal Case

A - 3

Attachment 2

Quantitative Results per Rhode Island Benefit Cost Test, 2018$

REDACTED

RHODE ISLAND BENEFIT COST TEST

Quantitative Analysis of Categories from the Docket 4600 Framework

Proposal Case - Portfolio RW400 + VW800 + RW200
Project - RW 400 MW Levelized 20 Year PPA

Filed under the Affordable Clean Energy Security Act ("ACES")

	Proposal Summary of Cost and Benefits for Business Case		**2018$ Benefit/Cost Totals (NPV in 2018$)**	**% Total Benefits %**
	Direct Cost of Project			
(1)	Proposal Case - Cost of energy from Project		($974,793,201)	
(2)	Proposal Case - Cost of RECs from Project		($359,152,141)	
(3)	**Direct Cost of Project energy + RECs** *(3) = (1) + (2)*		**($1,333,945,342)**	
(4)	Market value of Energy from Project		$908,384,843	*37.4%*
(5)	Market value of Project RECs retired (used) for RES or sold		$430,227,231	*17.7%*
(6)	**Net Direct Benefits** *(6) = (3) + (4) + (5)*		**$4,666,733**	
	Indirect Benefits			
(7)	RI Energy Market Price Change Impact (Distribution load * Change in Annual Energy Market Value)		**$86,967,434**	*3.6%*
(8)	REC Market Price Change Impact (Qty of RECs acquired at market price for distribution load * Change in REC Market Price)		**$0**	*0.0%*
(9)	Forward Commitment: Capacity Value	*beyond the capabilities of the modeling system to quantify accurately*		
(10)	Forward Commitment: Avoided Ancillary Services Value	*beyond the capabilities of the modeling system to quantify accurately*		
(11)	**Total Indirect Benefits** *(11) = (7) + (8) + (9) + (10)*		**$86,967,434**	
(12)	**Total Net Benefits (Cost) [Direct + Indirect]** *(12) = (6) + (11)*		**$91,634,166**	
	Other Benefits			
(13)	Societal Impact of Reduction in GHG Emissions		$533,172,942	*22.0%*
(14)	Societal Impact of Reduction in NOx Emissions		$10,761,161	*0.4%*
(15)	Economic Benefit to Rhode Island		$405,125,090	*16.7%*
(16)	Increase in Project PPA market value from year with extreme Winter fuel prices ocurring once in 15 years		$25,369,408	*1.0%*
(17)	Impact of Reduction in gas supply cost to RI gas customers		$28,701,165	*1.2%*
(18)	**Total Other Benefits** *(18) = (13) + (14) + (15) + (16) + (17)*		**$1,003,129,766**	
(19)	**Total Net Benefits (Cost) [Direct + Indirect + Other]** *(19) = (6) + (11) + (18)*		**$1,094,763,932**	
(20)	**Program Remuneration** *(20) = (3) x 2.75%*	@ 2.75%	**($36,683,497)**	
(21)	**RI Test - Total Benefits** *(21) = (4) + (5) + (11) + (18)*		**$2,428,709,274**	100.0%
(22)	**RI Test - Total Costs** *(22) = (3) + (20)*		**($1,370,628,839)**	

RHODE ISLAND BENEFIT COST TEST (*Ratio*): 1.77

Notes and Sources

(11) Indirect economic benefits to RI from the Proposal Case

(13) and (14) Environmental benefits shown are calculated on a societal level per Docket 4600 guidance. Using a 'Consumption-based' emission accounting methodology per the RI-EC4 Rhode Island Greenhouse Gas Emission Reduction Plan (December 2016) the Rhode Island state-level GHG and NOx reduction are $108,987,521 and $2,203,057 respectively.

(15) **Economic Benefit to Rhode Island from** Navigant Consulting in the "Advisory Opinion on the Economic Development Benefits of the Revolution Wind Project", Dated 10/5/2018. (Summary provided in Section 5.2 Conclusions).

(21) Total Benefits equal the sum of the NPV of each benefit component:
[Avoided market value or Energy + projected market value of RECs retired/sold + RI Energy Market Price Change Impact + REC Market Price Change Impact + Capacity Market Benefits + Ancillary Services Market Benefits + Non-embedded Greenhouse Gas Reduction Benefits + Non-embedded NOx Reduction Benefits + Economic Benefit to Rhode Island] + Extreme Winter Market Value Impact +Gas supply cost reduction

(22) Total Costs equal the sum of the NPV of each cost component:
[Proposal Cost of energy from Project + Proposal Cost of RECs from Project + Program Remuneration]
Rhode Island Benefit Cost Ratio = NPV Total Benefits / NPV Total Costs

Attachment 3

Base Case Results

REDACTED

A - 6

Rhode Island Procurement of Revolution Wind 400MW
Base Case Results

nationalgrid

January 29, 2019

REDACTED

Summary / Agenda

A - 7

1. RI RW 200 MW Base Case: What it is and is not
2. Capacity Balance for New England (MW)
3. Capacity Mix (MW) by Fuel Type
4. Generation Mix (MWh)
5. Model Selected Capacity Retirements and Additions (MW)
6. New England Class 1 RPS and MA CES Requirements (GWh)
7. Projected LMPs by Area (2018$/MWh)
8. ENELYTIX Results Workbook Content

1.RI RW 400 MW Base Case: What it is and is not

- It is not a plan for the Rhode Island electric sector and should not be viewed as such.
- It is the reference point against which we measure the incremental impacts of a future in which RI procures 400 MW from Revolution Wind, MA procures 800 MW from Vineyard Wind and CT procures 200 MW from Revolution Wind. As such it is a "counterfactual" projection of key parameters including electricity prices, REC prices, carbon emissions and gas consumption in which none of those offshore wind projects are developed.
- It assumes:
  - Compliance with all legislative requirements and regulations in effect as of July 1, 2017 including class 1 Renewable Portfolio Standard (RPS) regulations in all New England states, the cap on carbon emissions from electric generating units located in MA and the Clean Energy Standard (CES) promulgated August 11, 2017
  - Implementation of the NECEC Hydro project selected in the 83D procurement, including all associated transmission developments
  - Implementation of two tranches of 83C generic offshore wind of 400 MW each in January 2027 and January 2029 procured to comply with MA 83C legislation
  - Compliance with Class 1 RPS requirements of New England states and with MA CES requirements through a combination of the resources noted above, class 1 RPS eligible resources as of 2020, alternative compliance payments (ACPs) and generic clean energy additions developed on a merchant basis.

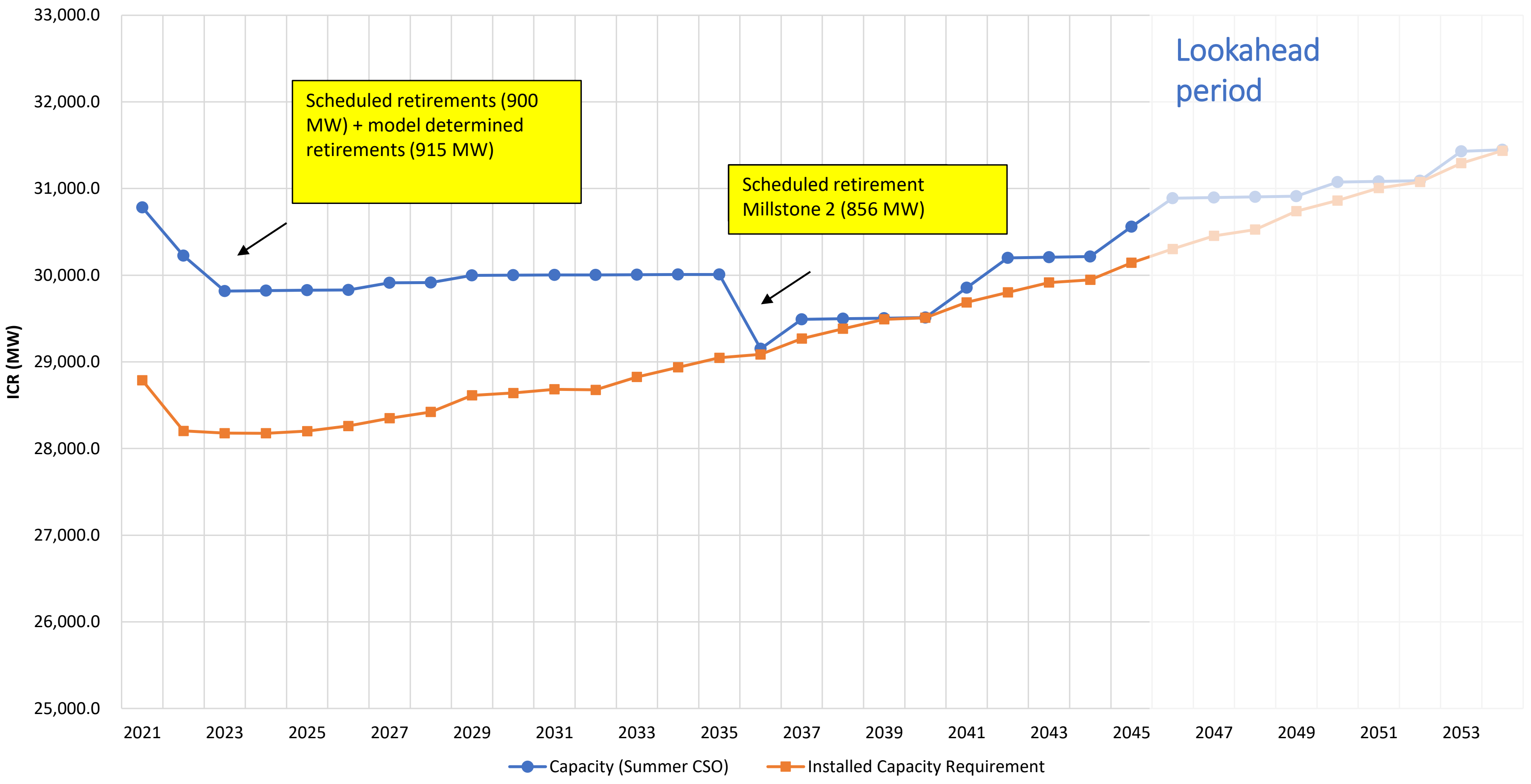
Key Changes in assumptions relative to MA 83C Base Case

- Projections
  - Load Forecast revised per ISO-NE CELT 2018 (Energy / Peak forecast)
  - Resource adequacy requirements (ICR) recalculated per FCA-12 results and revised load forecast
  - Revised behind the meter PV and distributed PV projections per ISO-NE CELT 2018
- RPS/CES Requirements
  - Revised MA and CT state RPS targets
  - Revised CT ACP prices
  - Recalculated RPS and MA CES requirements per revised load forecast
  - Revised biomass RPS eligibility in CT, inclusion of RECs from behind-the-meter biomass units in ME & northern ME
- Emissions
  - RGGI price projections revised
  - Inclusion of additional emissions associated with winter dual-fuel unit switching
- Near term retirements and additions
  - Incremental scheduled retirements per ISO-NE retirement tracker
  - New generators having cleared FCA-12, incorporated upgrades to existing units
  - 53.6 MW of Fuel Cell and Biomass generation from the CT 2018 Clean energy procurement
- Transmission
  - 83C tranches 3 and 4 POI revised from aggregate SEMA/RI to Brayton Point
- Fuel Price
  - Revised fuel price projections for Natural Gas, Distillate Fuel Oil, Residual Fuel Oil
  - Introduced Dual-fuel unit switching from gas to fuel oil on winter days with high gas prices
  - Revised fuel prices for Mystic 8 and 9 units after June 2024
- All prices and costs updated to 2018$ (Capital costs, FOM, VOM, ACPs)

REDACTED

2.a. Capacity Balance for New England (MW)

A - 10



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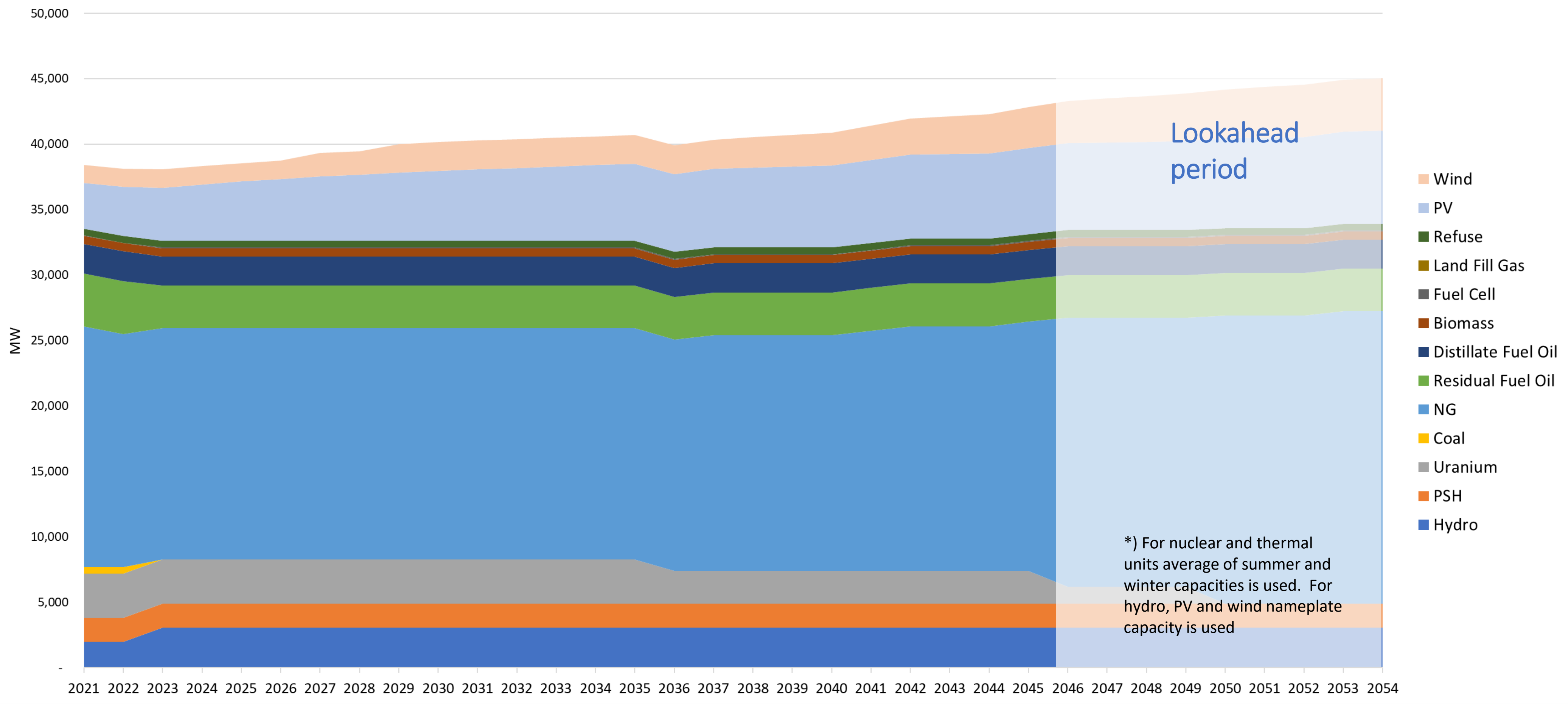
2.b. Capacity Balance by Zone (MW)

A - 11

REDACTED

3.a. Nameplate Capacity (MW) by Fuel Type

A - 12



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3.b. Nameplate Capacity (MW) by Fuel Type

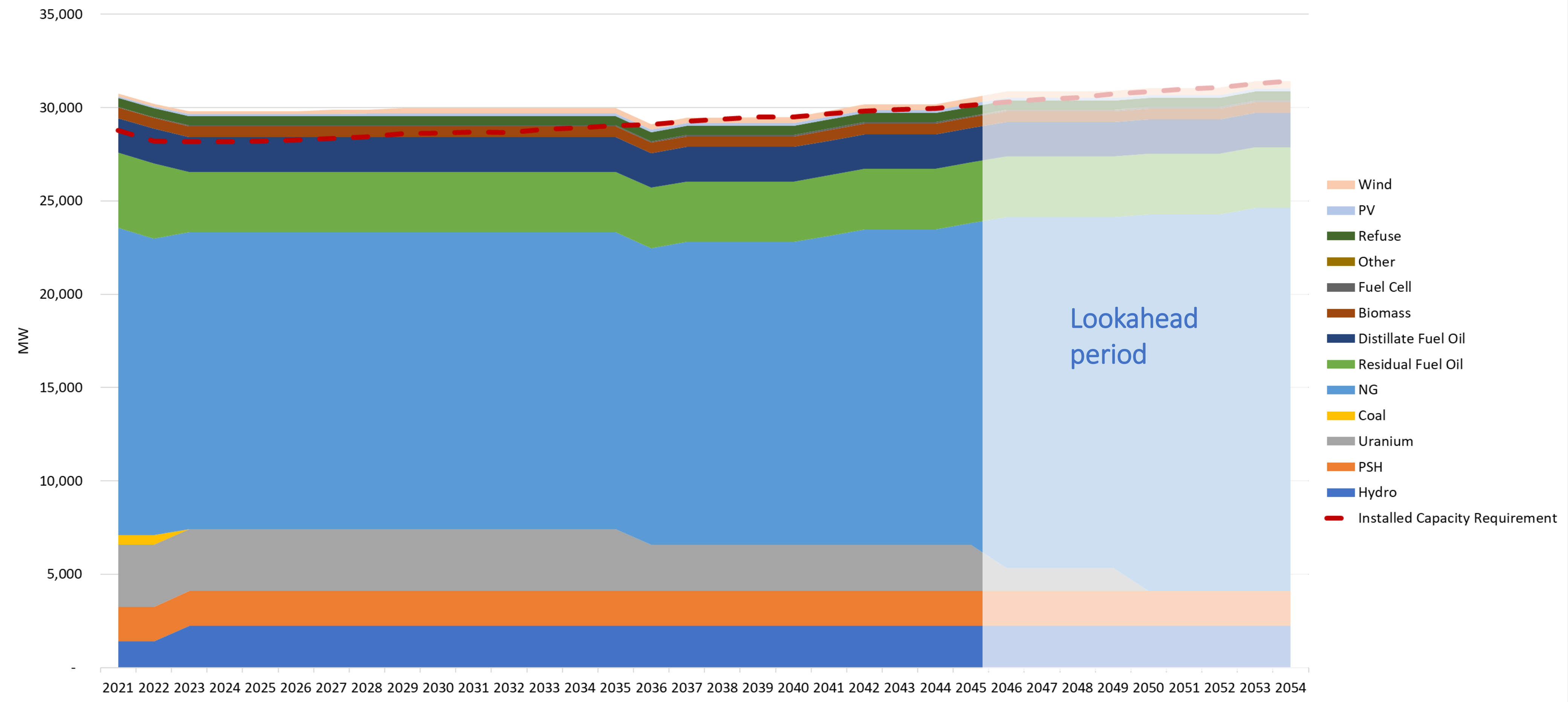
A - 13

	Hydro	PSH	Uranium	Coal	NG	Residual Fuel Oil	Distillate Fuel Oil	Biomass	Fuel Cell	Land Fill Gas	PV	Refuse	Wind	Grand Total
2021	1,962	1,864	3,344	535	18,353	4,054	2,269	622	23	2	3,483	516	1,402	38,428
2022	1,962	1,864	3,344	535	17,793	4,054	2,263	622	23	2	3,764	515	1,402	38,143
2023	3,052	1,864	3,344	-	17,680	3,259	2,215	624	75	2	4,036	515	1,402	38,067
2024	3,052	1,864	3,344	-	17,680	3,259	2,215	624	75	2	4,290	515	1,402	38,321
2025	3,052	1,864	3,344	-	17,680	3,259	2,215	624	75	2	4,528	515	1,402	38,559
2026	3,052	1,864	3,344	-	17,680	3,259	2,215	624	75	2	4,716	515	1,402	38,747
2027	3,052	1,864	3,344	-	17,680	3,259	2,215	624	75	2	4,898	515	1,802	39,330
2028	3,052	1,864	3,344	-	17,680	3,259	2,215	624	75	2	5,030	515	1,802	39,461
2029	3,052	1,864	3,344	-	17,680	3,259	2,215	624	75	2	5,187	515	2,202	40,018
2030	3,052	1,864	3,344	-	17,680	3,259	2,215	624	75	2	5,320	515	2,202	40,151
2031	3,052	1,864	3,344	-	17,680	3,259	2,215	624	75	2	5,443	515	2,202	40,274
2032	3,052	1,864	3,344	-	17,680	3,259	2,215	624	75	2	5,544	515	2,202	40,375
2033	3,052	1,864	3,344	-	17,680	3,259	2,215	624	75	2	5,665	515	2,202	40,496
2034	3,052	1,864	3,344	-	17,680	3,259	2,215	624	75	2	5,766	515	2,202	40,597
2035	3,052	1,864	3,344	-	17,680	3,259	2,215	624	75	2	5,861	515	2,202	40,692
2036	3,052	1,864	2,485	-	17,680	3,259	2,215	624	75	2	5,936	515	2,202	39,908
2037	3,052	1,864	2,485	-	18,018	3,259	2,215	624	75	2	6,036	515	2,203	40,347
2038	3,052	1,864	2,485	-	18,018	3,259	2,215	624	75	2	6,117	515	2,309	40,534
2039	3,052	1,864	2,485	-	18,018	3,259	2,215	624	75	2	6,194	515	2,416	40,718
2040	3,052	1,864	2,485	-	18,018	3,259	2,215	624	75	2	6,252	515	2,524	40,885
2041	3,052	1,864	2,485	-	18,356	3,259	2,215	624	75	2	6,339	515	2,629	41,414
2042	3,052	1,864	2,485	-	18,694	3,259	2,215	624	75	2	6,406	515	2,747	41,938
2043	3,052	1,864	2,485	-	18,694	3,259	2,215	624	75	2	6,472	515	2,866	42,122
2044	3,052	1,864	2,485	-	18,694	3,259	2,215	624	75	2	6,518	515	2,984	42,287
2045	3,052	1,864	2,485	-	19,032	3,259	2,215	624	75	2	6,595	515	3,097	42,814
2046	3,052	1,864	1,251	-	20,579	3,259	2,215	624	75	2	6,653	515	3,225	43,314
2047	3,052	1,864	1,251	-	20,579	3,259	2,215	624	75	2	6,709	515	3,352	43,497
2048	3,052	1,864	1,251	-	20,579	3,259	2,215	624	75	2	6,747	515	3,484	43,666
2049	3,052	1,864	1,251	-	20,579	3,259	2,215	624	75	2	6,816	515	3,605	43,857
2050	3,052	1,864	-	-	21,983	3,259	2,215	624	75	2	6,868	515	3,728	44,184
2051	3,052	1,864	-	-	21,983	3,259	2,215	624	75	2	6,917	515	3,857	44,363
2052	3,052	1,864	-	-	21,983	3,259	2,215	624	75	2	6,948	515	3,993	44,530
2053	3,052	1,864	-	-	22,321	3,259	2,215	624	75	2	7,012	515	3,993	44,932
2054	3,052	1,864	-	-	22,321	3,259	2,215	624	75	2	7,118	515	3,993	45,038

Lookahead period

3.c. ICAP Capacity Contribution (MW) by Fuel Type

A - 14



3.d. ICAP Capacity Contribution (MW) by Fuel Type

A - 15

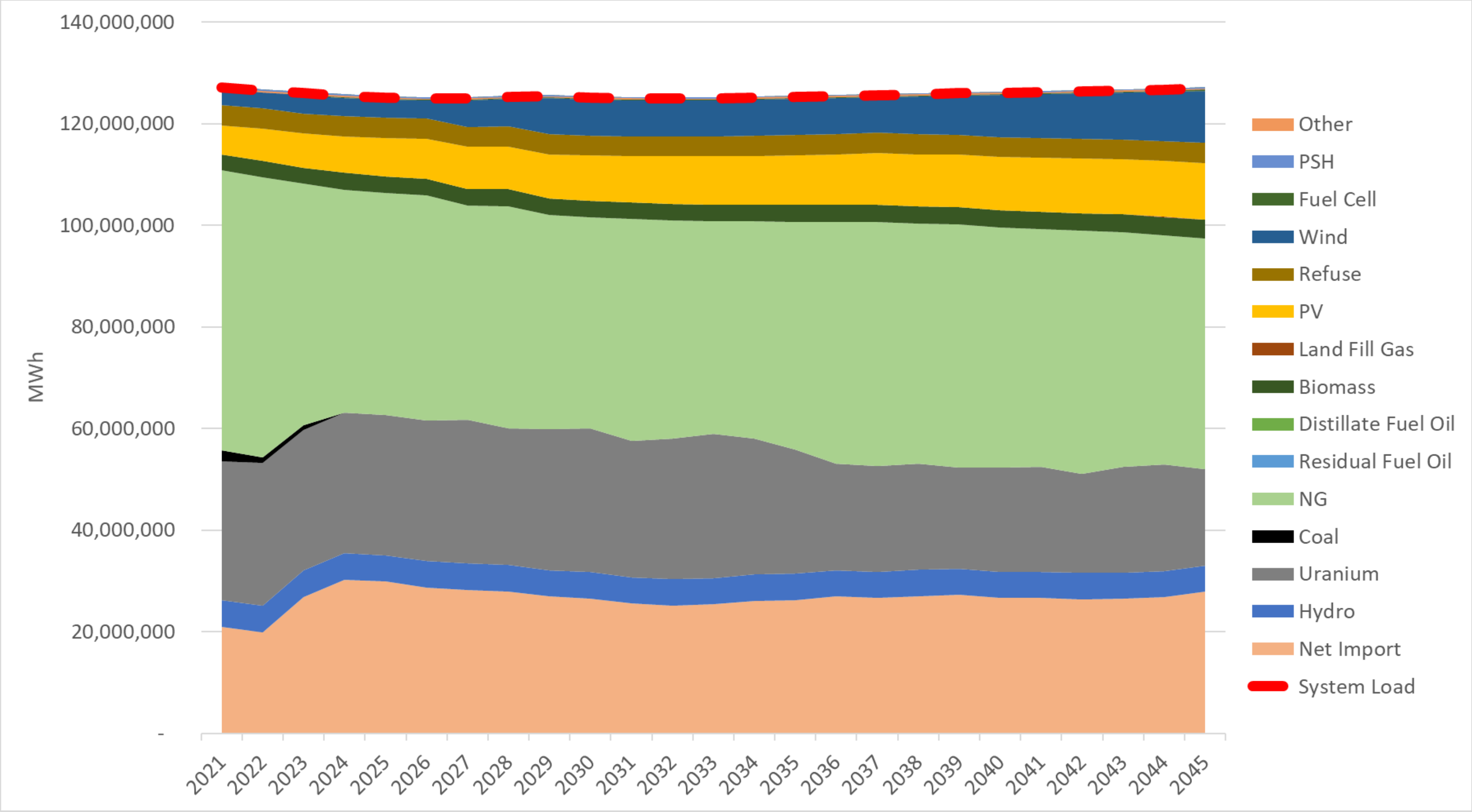
	Hydro	PSH	Uranium	Coal	NG	Residual Fuel Oil	Distillate Fuel Oil	Biomass	Fuel Cell	Other	PV	Refuse	Wind	Grand Total	Installed Capacity Requirement
2021	1,383	1,859	3,331	533	16,447	4,026	1,857	572	22	1	98	490	132	-	28,787
2022	1,383	1,859	3,331	533	15,887	4,026	1,857	572	22	1	102	490	132	-	28,203
2023	2,233	1,859	3,331	-	15,894	3,246	1,847	574	74	1	107	490	132	-	28,177
2024	2,233	1,859	3,331	-	15,894	3,246	1,847	574	74	1	112	490	132	-	28,176
2025	2,233	1,859	3,331	-	15,894	3,246	1,847	574	74	1	116	490	132	-	28,201
2026	2,233	1,859	3,331	-	15,894	3,246	1,847	574	74	1	119	490	132	-	28,261
2027	2,233	1,859	3,331	-	15,894	3,246	1,847	574	74	1	122	490	212	-	28,350
2028	2,233	1,859	3,331	-	15,894	3,246	1,847	574	74	1	124	490	212	-	28,422
2029	2,233	1,859	3,331	-	15,894	3,246	1,847	574	74	1	127	490	292	-	28,614
2030	2,233	1,859	3,331	-	15,894	3,246	1,847	574	74	1	129	490	292	-	28,640
2031	2,233	1,859	3,331	-	15,894	3,246	1,847	574	74	1	131	490	292	-	28,683
2032	2,233	1,859	3,331	-	15,894	3,246	1,847	574	74	1	133	490	292	-	28,676
2033	2,233	1,859	3,331	-	15,894	3,246	1,847	574	74	1	135	490	292	-	28,826
2034	2,233	1,859	3,331	-	15,894	3,246	1,847	574	74	1	137	490	292	-	28,937
2035	2,233	1,859	3,331	-	15,894	3,246	1,847	574	74	1	138	490	292	-	29,047
2036	2,233	1,859	2,472	-	15,894	3,246	1,847	574	74	1	140	490	292	-	29,086
2037	2,233	1,859	2,472	-	16,232	3,246	1,847	574	74	1	142	490	292	-	29,268
2038	2,233	1,859	2,472	-	16,232	3,246	1,847	574	74	1	143	490	297	-	29,382
2039	2,233	1,859	2,472	-	16,232	3,246	1,847	574	74	1	144	490	302	-	29,491
2040	2,233	1,859	2,472	-	16,232	3,246	1,847	574	74	1	145	490	308	-	29,509
2041	2,233	1,859	2,472	-	16,570	3,246	1,847	574	74	1	147	490	313	-	29,686
2042	2,233	1,859	2,472	-	16,908	3,246	1,847	574	74	1	148	490	319	-	29,801
2043	2,233	1,859	2,472	-	16,908	3,246	1,847	574	74	1	149	490	325	-	29,916
2044	2,233	1,859	2,472	-	16,908	3,246	1,847	574	74	1	150	490	331	-	29,947
2045	2,233	1,859	2,472	-	17,246	3,246	1,847	574	74	1	151	490	336	-	30,143
2046	2,233	1,859	1,247	-	18,793	3,246	1,847	574	74	1	152	490	343	-	30,303
2047	2,233	1,859	1,247	-	18,793	3,246	1,847	574	74	1	153	490	349	-	30,454
2048	2,233	1,859	1,247	-	18,793	3,246	1,847	574	74	1	154	490	356	-	30,526
2049	2,233	1,859	1,247	-	18,793	3,246	1,847	574	74	1	155	490	362	-	30,738
2050	2,233	1,859	[illegible]	-	20,197	3,246	1,847	574	74	1	156	490	368	-	30,862
2051	2,233	1,859	-	-	20,197	3,246	1,847	574	74	1	157	490	374	-	31,005
2052	2,233	1,859	-	-	20,197	3,246	1,847	574	74	1	157	490	381	-	31,075
2053	2,233	1,859	-	-	20,535	3,246	1,847	574	74	1	159	490	381	-	31,293
2054	2,233	1,859	-	-	20,535	3,246	1,847	574	74	1	179	490	381	-	31,437

Lookahead period

REDACTED

4. Generation Mix (MWh)

A - 16



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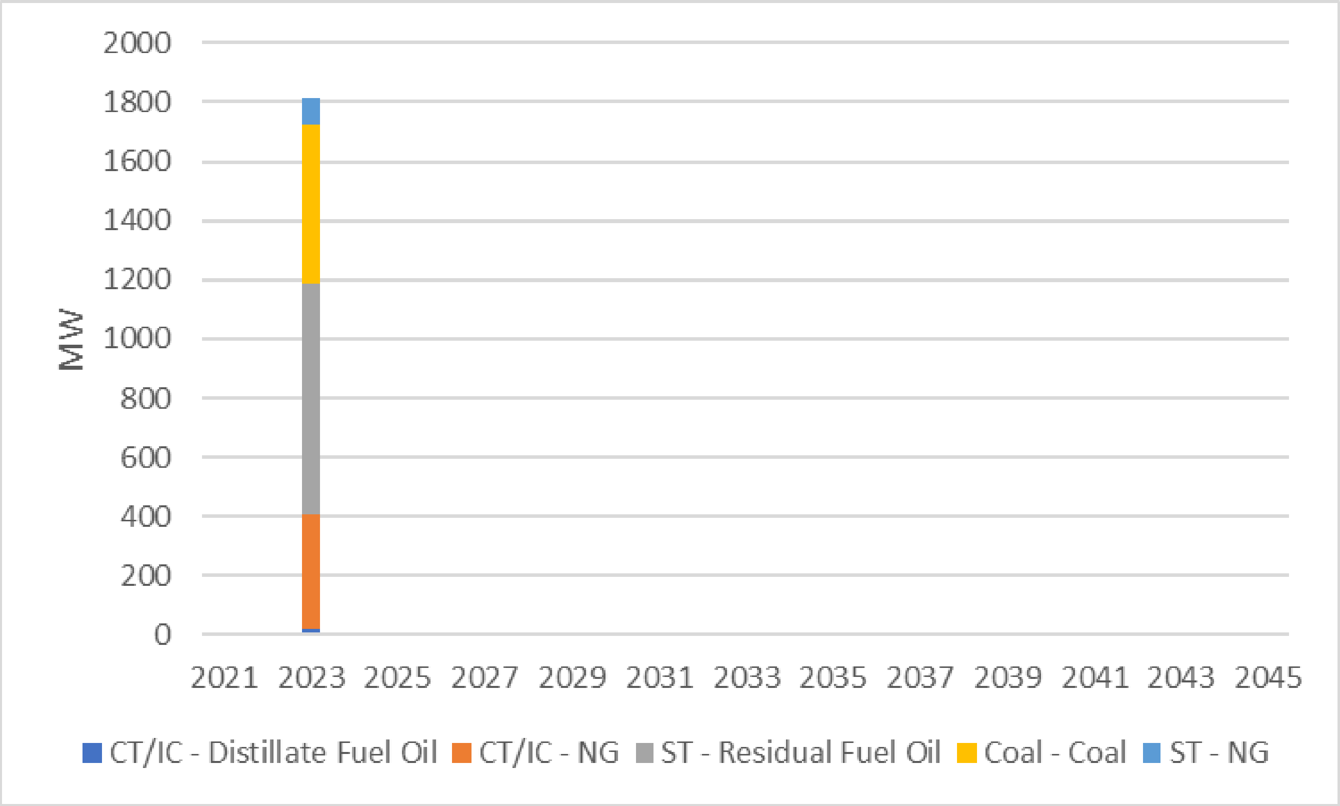
5.a. Model Selected Retirements (MW)

A - 17



2045

All Retirements
1,816 MW

Boiler – Natural Gas
94 MW

Boiler - Coal
533 MW

Boiler - RFO
783 MW

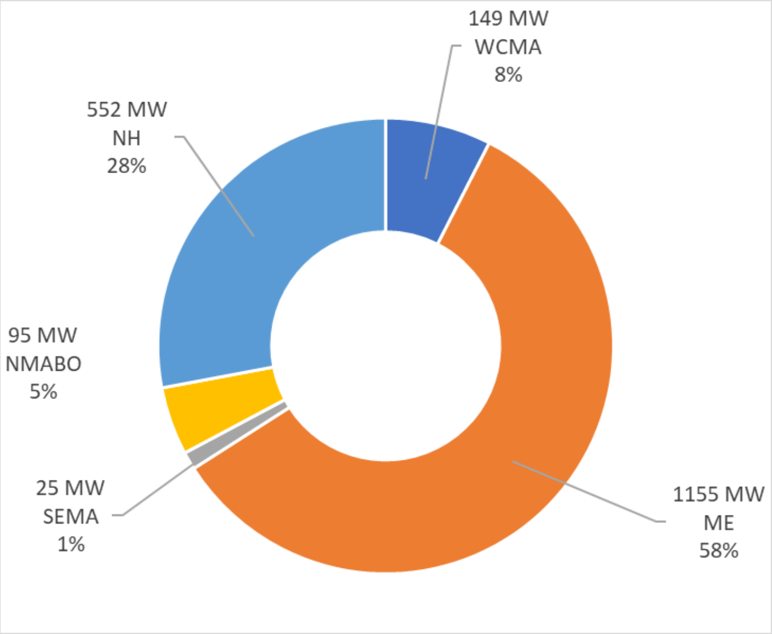
Peaker Natural Gas
384 MW

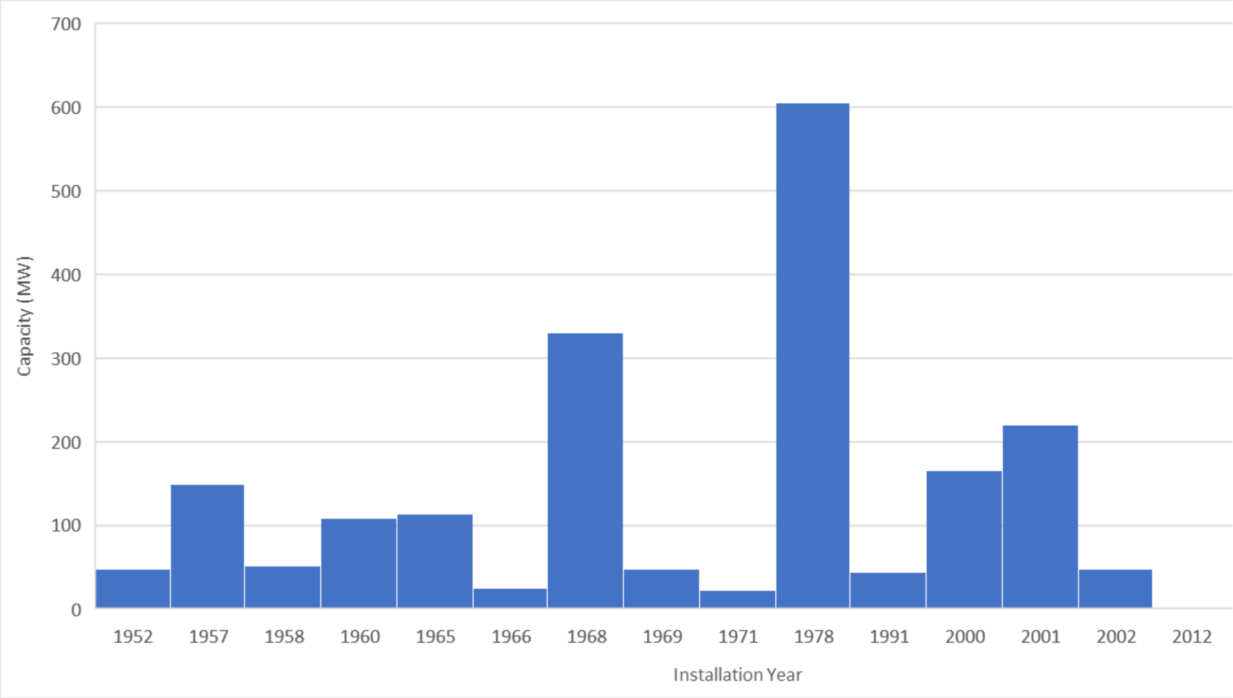
Peaker DFO
21 MW

5.b. Model Selected Retirements (MW)

A - 18

Model Selected Retirements by Load Zone (left) and Vintage (right)





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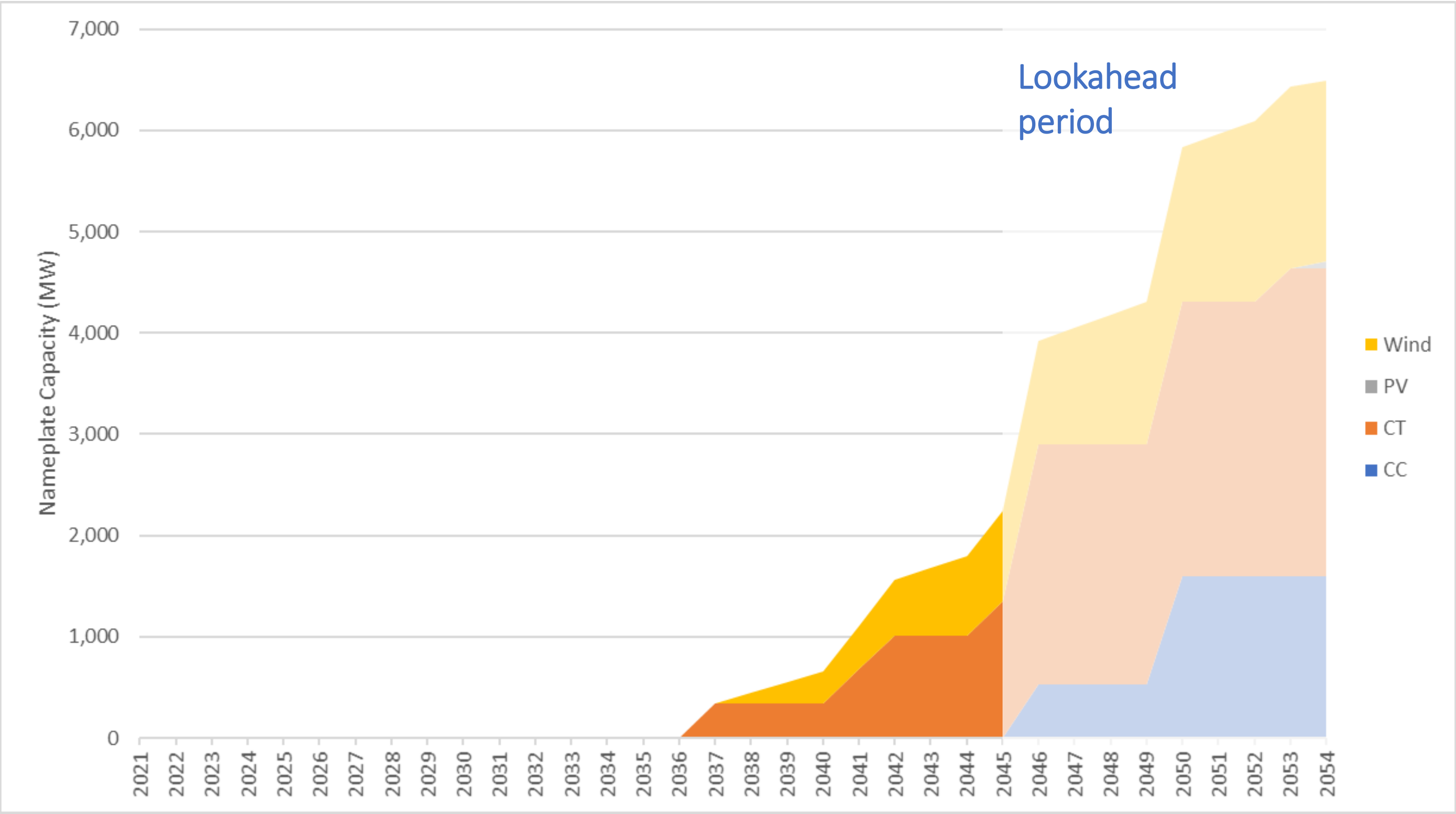
5.c. Model Selected New Capacity Additions (MW)



2045

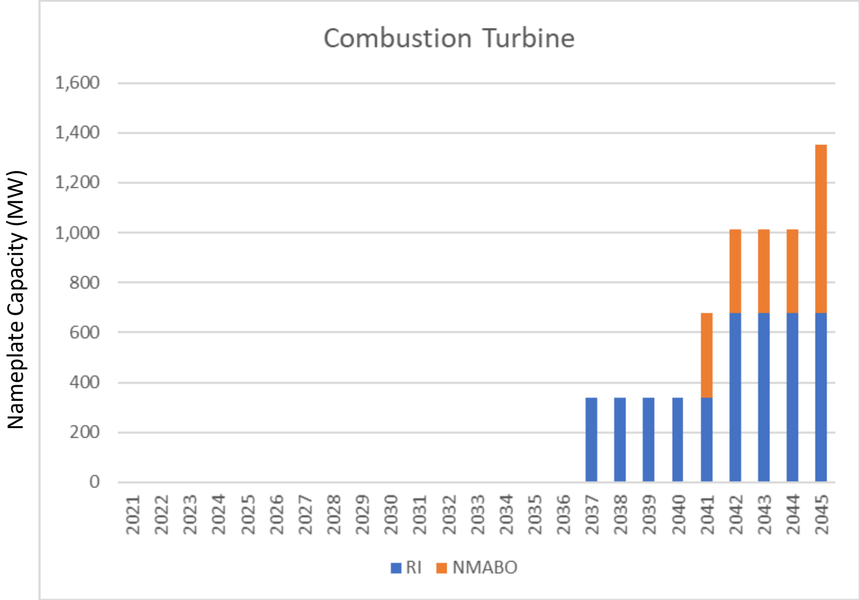
2,247 MW
New Nameplate Capacity

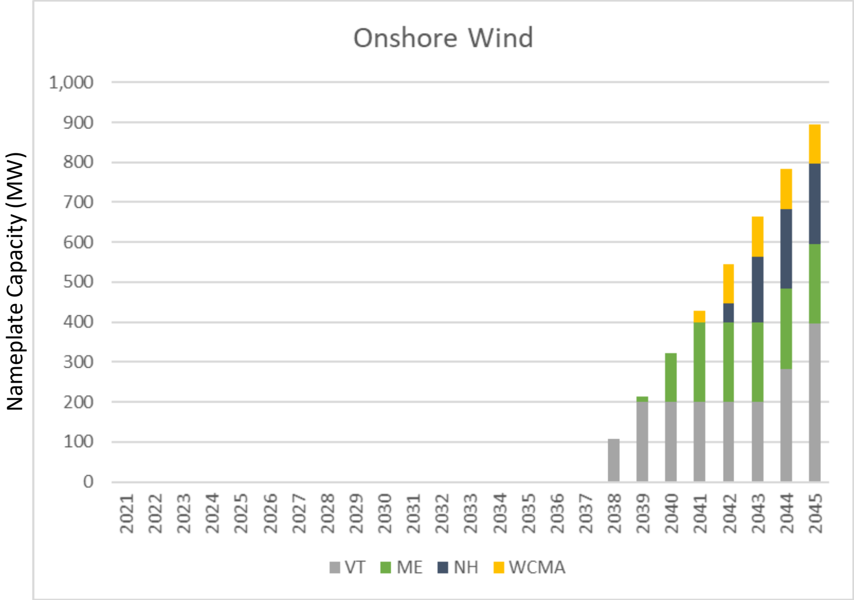
Onshore Wind
895 MW
(5 Installations)

CT (Peakers)
1,352 MW
(4 Installations)

5.d. Model Selected New Capacity Additions (MW)

Model Selected Capacity Additions by Load Zone (Nameplate Capacity)





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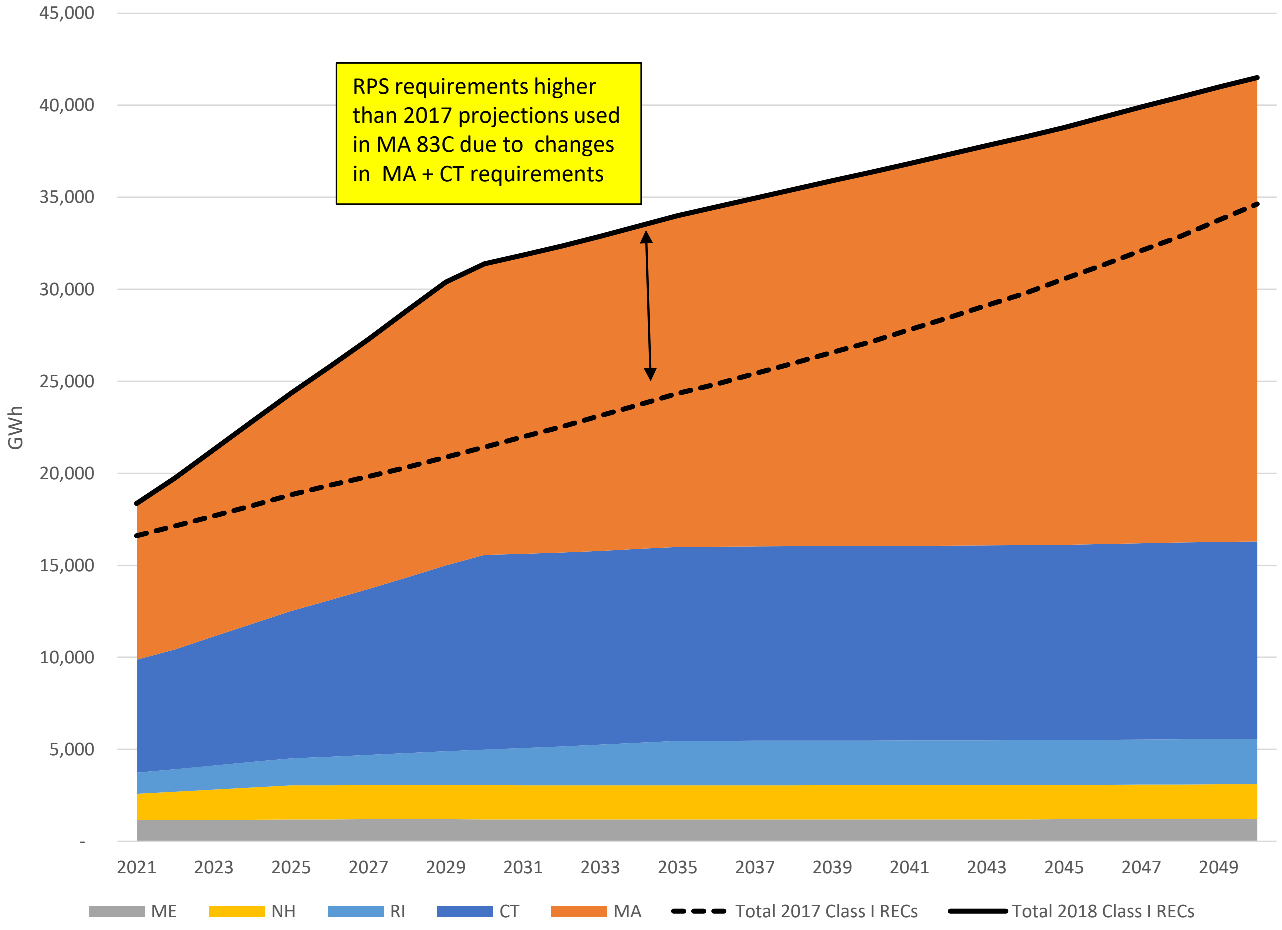
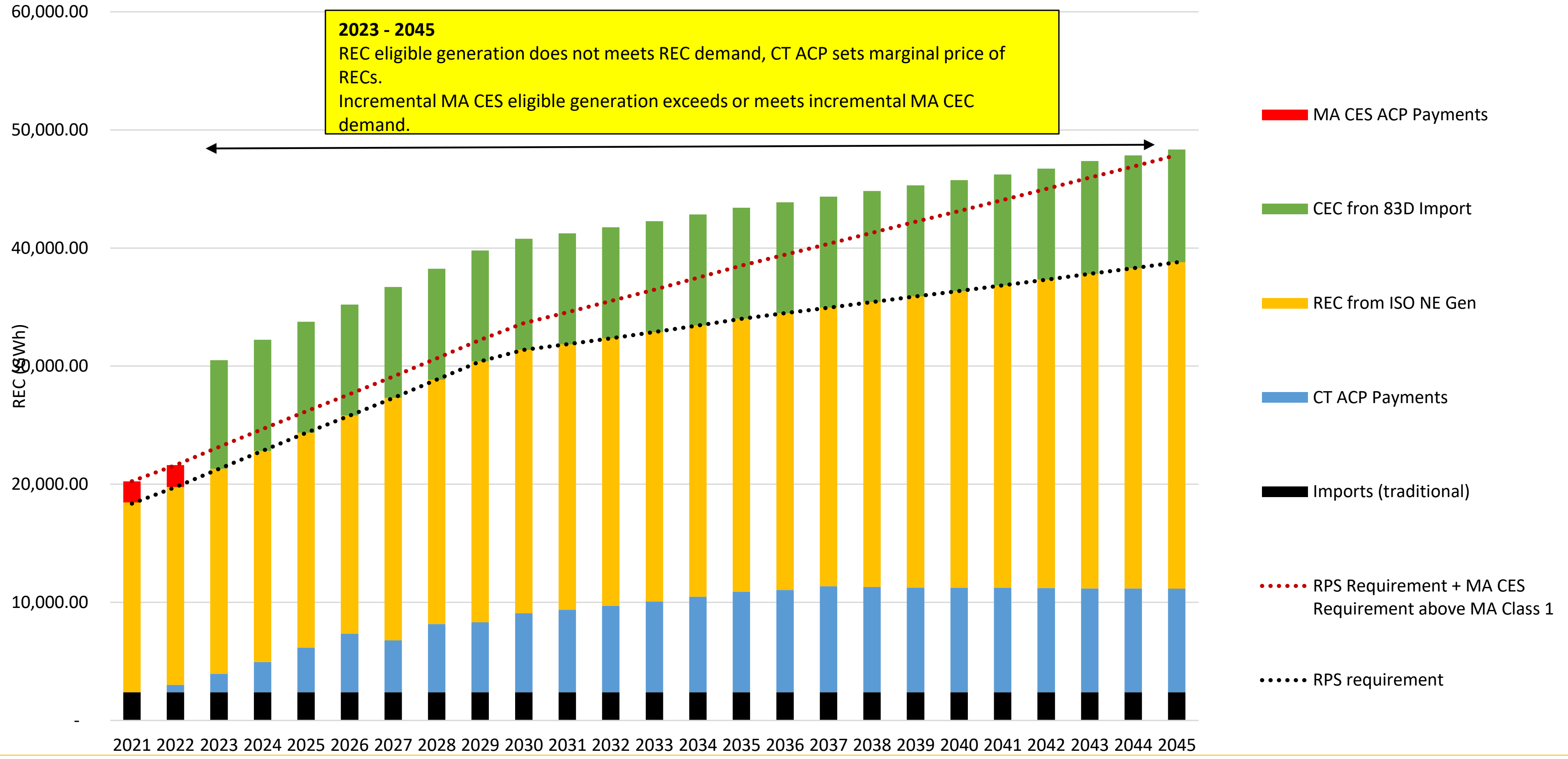
6.a. New England Class 1 RPS Requirements (GWh)

A - 21



6.b. Class 1 RPS and MA CES Requirements vs Resources

A - 22



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6.c. REC and CEC Prices (2018$/MWh)

A - 23

[redacted]

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6.d. Class 1 RPS & MA CES Reqts & Resources (GWh); REC & CEC prices (2018 $/MWh)

[redacted]

REDACTED

7. Projected Annual Average LMPs by Area (2018$/MWh)

A - 25

[redacted]

9. ENELYTIX Results Workbook

Tab	Content
1 New Additions	Shows new generation additions as selected by the capacity expansion model. See Input Assumptions Document information on fixed new additions
2 Retirements	Shows generation retirements as selected by the capacity expansion model. See Input Assumptions Document information on fixed retirements
3 GenMix_Gen	Generation mix by fuel type in MWh by year
3a Interchange	Shows imports into New England by Source
4 CFs All	Capacity factor by technology/fuel by year. Capacity factor in each category is computed as total generation by category divided by total capacity and by number of hours in a year
5 CFs New CCs and CTs	Capacity factors for new CC and CT generators suggested by the capacity expansion model
6 CFs Wind and PV	Capacity factors of new wind and PV generators by year by location
7 ProdCostDet	Annual generation and production cost by New England Zone by cost category
8 Gas BurnAnn	Annual natural gas burn by New England generators in MMBtu
9 Fuel Switching	Daily data on fuel switching, switched fuel use and incremental CO2 emissions
10 MA CO2 Emiss	CO2 emissions by generating units in Massachusetts that are subject to CO2 cap. Emissions are in lbs.
11a, b, c SysEmiss	Emissions of CO2, Nox and Sox by generating units in New England by zone and state Emissions are in lbs.
12 AreaLMP_Monthly	LMPs by month by year for each New England Zone reported for On Peak, Off Peak and 24-hour periods
13 AreaLMP_Ann	LMPs by year for each New England Zone reported for On Peak, Off Peak and 24-hour periods
14 AreaLoad &Cost	Load and Load Cost by zone by year. Load Cost in each zone is computed as a product of hourly load and hourly LMP in that zone summed over year
15 CongRent	Congestion rent and count of binding hours for all New England constraints by year
16 Interface Flows	Flows on New England interfaces. Flows are reported daily for each year 2020-2040 on average during On Peak and Off Peak hours of the day
18 Tech_program REC GWh	Detailed layout of REC contribution by source
19 Zone REC GWh	Contribution to REC by Zone
20 CES	CES Requirements and level met via ACP payments
21 REC Rev by Zone	Auxiliary worksheet showing Class 1 REC revenues received by generators by Zone. Used to restate true VOM costs
22 Project Detail	Generation and Revenue Reported for the Project. Not available for the Base Case

REDACTED

Attachment 4

TCR Qualifications

REDACTED

Tabors Caramanis Rudkevich

Corporate Overview

Tabors Caramanis Rudkevich (TCR) is an engineering economics consulting group. TCR provides consulting, simulation modelling and litigation support on a range of electric market design, market operation and asset valuation issues at both the federal and state level. TCR staff have provided these services to a wide range of clients including generation and transmission companies, Independent System Operators (ISOs) and Regional Transmission Operators (RTOs), distribution utilities, energy policy makers and regulators, efficiency program administrators, environmental groups and consumer advocates.

TCR brings extensive experience gained over the past 40 years to its engagements. The senior members of our team have consulted on the design and operation of wholesale power markets in the US, Canada, the UK, Europe, Australia, the Middle East and Mexico. We have analyzed the design and operation of retail markets throughout the US and are currently focusing on a range of “utility of the future” issues including market design, valuation of distributed energy resources (DER) and rate design. Our team members have provided litigation support and expert testimony on market behavior, contract arbitration, ratemaking and asset valuations at the Federal level, in arbitrations and state regulatory proceedings. We have prepared asset valuations of a wide range of electricity resources, including gas-fired units, wind units and energy efficiency programs

TCR brings a multi-disciplinary, quantitative based approach to our analyses. Our team has a comprehensive range of technical, economic, financial and regulatory expertise. We apply state-of-the-art analytical tools and simulation models, in particular ENELYTIX®, a cloud-based electric market modeling environment, TCR licenses from Newton Energy Group, its research affiliate. TCR provides analyses with rigorous results that withstand peer reviews and litigation scrutiny. We present those analyses and results clearly and convincingly to both technical and non-technical audiences

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1. ANALYTIC CAPABILITIES

Power System Simulation Modeling

TCR extensively uses the stat-of-the-art Security Constrained Unit Commitment and Dispatch modeling tool ENELYTIX®[1]. TCR licenses ENELYTIX from its affiliate Newton Energy Group (NEG). NEG developed and supports ENELYTIX® as 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 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 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 currently 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.

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

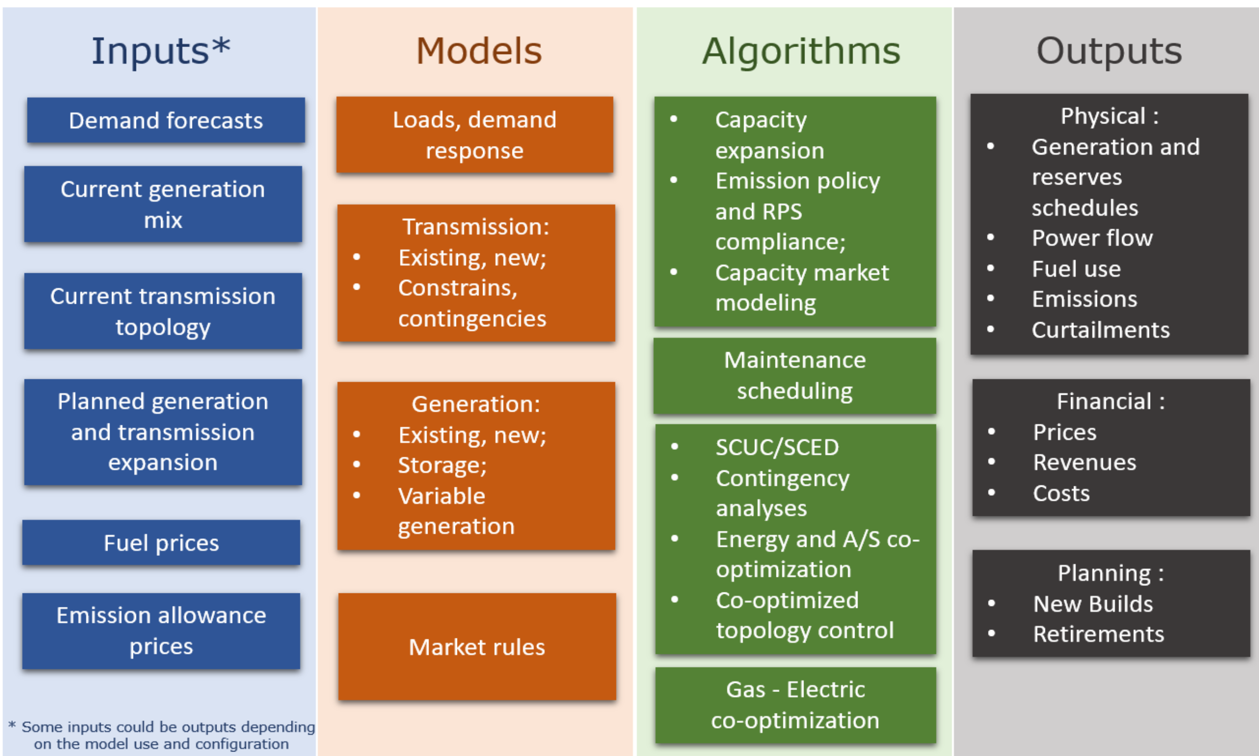
[1] ENELYTIX® is a registered trademark of Newton Energy Group, LLC.

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.

Figure 1. Analytical Structure of PSO



2. RELEVANT PROJECT EXPERIENCE

Analyses and Projections of Marginal Emissions of Carbon in New England and New York in Various Consulting Engagements.

Quantitative Evaluation of Long-Term Contracts for Clean Energy Generation Projects, Rhode Island. In September 2018 National Grid issued an RFP for the supply of energy as well as Renewable Energy Certificates ("RECs") under long-term power purchase agreements (PPAs) from up to 400 megawatts ("MW") of newly developed renewable energy projects. National Grid retained TCR to help it evaluate the quantitative costs and benefits of the proposals over a 25 year evaluation period. The costs and benefits include the proposals' annual costs of energy and RECs as well as the quantity and value of reductions in annual emissions of carbon and NOX and in annual market prices of energy and of RECs caused by each proposal relative to the Base Case. TCR is developing the projections of costs and benefits using ENELYTIX® to simulate the hourly operation of the New England electric energy market under a Base Case and under each Proposal Case. The Base Case provides a "counterfactual" projection of energy and REC costs, as well as carbon emissions, under a future in which National Grid does not acquire supply from up to 400 MW of renewable energy resources. April 2018 – ongoing.

Quantitative Evaluation of Long-Term Contracts for Clean Energy Generation Projects, Massachusetts. In March 2017, to comply with Section 83D of the Massachusetts Green Communities Act, Massachusetts electric distribution companies ("EDCs') issued a Request for Proposals for long term contracts for 9,450 gigawatt hours of clean energy supply from onshore resources. The EDCs retained TCR to help them, in cooperation with the Department of Energy Resources ("DOER") and an Independent Evaluator, to evaluate the quantitative costs and benefits of over 50 distinct Proposals and Portfolios of those distinct Proposals. The costs and benefits TCR evaluated included annual costs of energy and renewable energy certificates (RECs") from the proposals as well as the value of reductions in annual carbon emissions, market prices of energy and market prices of RECs. TCR developed projections of each proposal's costs and benefits over a 25 year evaluation period based upon the bids from each Proposal and the outputs of TCR's simulation modeling of each proposal Case. TCR used ENELYTIX®, a cloud-based market modeling tool licensed from affiliate NEG, to simulate the hourly operation of the New England electric energy market under a Base Case and under each Proposal Case. The Base Case provided a "counterfactual" projection of energy and capacity costs, as well as carbon emissions, under a future in which the EDCs did not acquire for 9,450 gigawatt hours of clean energy. TCR used a Greenhouse Gas (GHG) Inventory model to calculate the impact of each proposal on the annual carbon emissions attributable to Massachusetts. The EDCs filed the TCR report as Exhibit JU-6 in Massachusetts DPU Docket 18-64. June 2017 – ongoing.

Quantitative Evaluation of Long-Term Contracts for Offshore Wind Projects, Massachusetts**.** In June 2017, to comply with Section 83C of the Massachusetts Green Communities Act, Massachusetts electric distribution companies ("EDCs') issued a Request for Proposals for long term contracts for up to 800 mega-watts (MW) of Offshore Wind Energy Generation. The EDCs retained TCR to help them, in cooperation with the Department of Energy Resources ("DOER") and an Independent Evaluator, to evaluate the quantitative costs and benefits of over 20 distinct Proposals and Portfolios of those distinct Proposals. The costs and benefits TCR evaluated included annual costs of energy and renewable energy certificates (RECs) from the proposals as well as the value of reductions in annual carbon emissions, market prices of energy and market prices of RECs. TCR developed projections of each proposal's costs and benefits over a 25 year evaluation period based upon the bids from each Proposal and the outputs of TCR's simulation modeling of each proposal Case. TCR used ENELYTIX®, a cloud-based market modeling tool licensed from affiliate NEG, to simulate the hourly operation of the New England electric energy market under a Base Case and under each Proposal Case. The Base Case provided a "counterfactual" projection of energy and capacity costs, as well as carbon emissions, under a future in which the EDCs did not acquire 800 MW of offshore wind. TCR used a Greenhouse Gas (GHG) Inventory model to calculate the impact of each proposal on the annual carbon emissions attributable to Massachusetts. The EDCs filed the TCR report as Exhibit JU-5 in Massachusetts DPU Docket 18-76. January 2018 – ongoing.

Avoided Energy Supply Cost in New England: 2015 Report (AESC 2015). The efficiency program administrators in New England retained TCR to develop projections through 2030 of marginal energy supply costs and carbon emissions that retail customers will avoid due to reductions in the use of electricity, natural gas, and other fuels resulting from energy efficiency programs offered by electric utilities, natural gas utilities and independent efficiency agencies. TCR used ENELYTIX®, a cloud-based market modeling tool licensed from affiliate NEG, to develop projections of the marginal electric energy and capacity costs that reductions in the use of electricity would avoid. AESC 2015 provides estimates of avoided costs the program administrators use to support their internal decision-making and regulatory filings for energy efficiency program cost-effectiveness analyses. TCR developed AESC 2015 through a major stakeholder process. November 2014 to April 2015.

Electric energy and capacity price suppression impacts of offshore wind (Long Island). TCR prepared a study of the impact of 250 MW of off-shore wind off the coast of Long Island on electric rates on Long Island. The study, commissioned by the New York Energy Policy Institute (NYEPI) of Stony Brook University, calculated the net rate impact, i.e., the incremental revenue requirements associated with the offshore wind facility less the reduction in wholesale energy and capacity prices in the Long Island Zone of the NYISO market as a result of the wind generation. TCR used ENELYTIX®, a cloud-based market modeling tool licensed from affiliate NEG, to project the wholesale energy and capacity prices under scenarios without the offshore wind facility and with the facility. October to November 2014.

3. TCR PROJECT LEADERS AND TEAM

The TCR team have professional backgrounds in electrical engineering and economics and extensive direct experience in power generation, transmission and power system modeling, particularly in New England, New York and across the organized markets of North America. The team has an in-depth understanding of, and direct experience with, both the calculation of the energy and capacity value of renewable resources integrated into the grid, with average and marginal emissions of carbon from every type of individual utility scale generation technology and the value to consumers of renewable technologies integrated into the electric grids.

Dr. Richard Tabors. President of Tabors Caramanis Rudkevich

Richard Tabors is an engineering economist and scientist with 40 years of domestic and international experience in energy planning and pricing, international development, and water and wastewater systems planning. Dr. Tabors provides expert consulting and testimony on the design, structuring, and regulation of power markets. His strength in these roles is based upon his ability to develop and manage effective client- and problem-focused teams that bring intellectual originality and rigor to the challenges of energy markets. Dr. Tabors is president of Tabors Caramanis Rudkevich (TCR) and Executive Vice President of NewGrid.

Dr. Tabors has provided expert assistance and testimony in numerous energy sector regulatory and arbitration cases at the federal, state, and provincial levels throughout the United States and Canada. He has provided technical assistance on electricity markets and market development to policy makers, utilities, merchant power developers, and transmission companies in North America, Europe, Latin

America, Australia, and the Middle East.

Dr. Tabors was a member of the MIT team that developed the theory of spot pricing upon which real-time pricing and locational marginal pricing of electricity and transmissions services are based (*Spot Pricing of Electricity*, Kluwer Academic Publishers, 1988). Dr. Tabors subsequently led teams addressing the restructuring of power markets in the United Kingdom, throughout the United States, and in Canada. Dr. Tabors has held a variety of research and teaching positions at MIT including assistant director of the Laboratory for Electromagnetic and Electronic Systems, associate director of the Technology and Policy master's program. Dr. Tabors is also a visiting professor of Electrical Engineering at the University of Strathclyde, Glasgow, Scotland.

Prior to founding TCR in 2014, Dr. Tabors was vice president and Energy Practice leader at Charles River Associates from 2004 to 2012. He was previously founder and president of Tabors Caramanis & Associates from 1988 until its sale to Charles River Associates in 2004.

Ph.D and MSSc Geography and Economics, The Maxwell School, Syracuse University
BA Biology, Dartmouth College
DSc. Engineering, University of Strathclyde, Glasgow Scotland (Honarary)

Professor Michael Caramanis. Principal

Michael Caramanis is a professor of systems and mechanical engineering at Boston University with expertise in mathematical economics, optimization, and stochastic dynamic decision making. He has 40 years' experience in electricity generation expansion, supply chain optimization, and spatiotemporal marginal costing of electricity in transmission and distribution networks. Dr. Caramanis has directed numerous research projects on these issues sponsored by the Electric Power Research Institute, New York State Energy Research and Development Authority, National Science Foundation, and the electric industry. He has authored or co-authored more than 100 refereed publications.

The focus of Dr. Caramanis' current research and consulting is marginal costing and dynamic pricing in smart power grids, grid topology control to mitigate congestion, and extending power markets into distribution systems in order to enable increased market participation by distribution connected loads, generation and storage resources.

Dr. Caramanis served as chair of the Greek Regulatory Authority for Energy from 2005 through 2009, and chaired the Investment Group of the International Energy Charter from 2004 to 2008. Dr. Caramanis was a member of the MIT team that developed the theory of spot pricing upon which real-time pricing and locational marginal pricing of electricity and transmissions services are based (*Spot Pricing of Electricity*, Kluwer Academic Publishers, 1988). Dr. Caramanis subsequently participated in pioneering the implementations of restructured wholesale electricity markets in the United Kingdom, Italy, the United States, and Spain.

PhD, Engineering, Harvard University
MS, Engineering, Harvard University
BS, Chemical Engineering, Stanford University

Dr. Alex Rudkevich. TCR principal, President of Newton Energy Group (NEG)

Dr. Rudkevich is a mathematician and economist with expertise in modeling power markets, design of power markets, and optimization of power systems and natural gas supply. Prior to co-founding NEG and TCR, Dr. Rudkevich was a vice president at Charles River Associates in its Energy & Environment practice. Previously he has served in senior consulting positions with Tabors Caramanis & Associates, Tellus Institute, Cambridge Energy Research Associates, and the Energy Research Institute of the Russian Academy of Sciences in Moscow.

Alex has over 30 years' experience providing consulting, research and expert testimony on the design and operation of power systems. His consulting includes valuation of generation and transmission assets; price forecasting and development of forward curves; market design; evaluation of alternative market designs for electric energy, capacity, ancillary services, assessments of financial transmission rights and marginal losses; and analyses of market power and mitigation measures.

At NEG Alex developed ENELYTIX®, a cloud based environment for modeling power markets. TCR has used ENELYTIX® to prepare valuations of existing and proposed generation and transmission assets and to analyze power market designs throughout the United States, Canada, and Mexico. Alex used ENELYTIX® to develop projections of electric energy and capacity prices for the Avoided Energy Supply Cost in New England 2015 study (AESC 2015).

Dr. Rudkevich is leading a multi-disciplinary team on a major ARPA-E funded project to develop market designs and algorithms for co-optimization of wholesale natural gas and electric markets. Other representative projects include development of an advanced method of topology control for the electric grid, technical direction of economic analysis for the Eastern Interconnection Planning Collaborative, cost-benefit analysis of the implementation of a nodal market design for the Electric Reliability Council of Texas, and analysis of congestion for the Department of Energy's first National Electric Transmission Congestion Study.

Ph.D. Energy Economics and Technology, Melentiev Energy Systems Institute, Russian Academy of Sciences, Irkutsk, Russia
A.B.D. System Analysis and Operations Research, Computing Center of the Russian Academy of Sciences, Moscow, Russia
M.S. Applied Mathematics, Gubkin Russian State University of Oil and Gas, Moscow, Russia

J Richard (Rick) Hornby. Senior Consultant

Rick Hornby is an industrial engineer and energy policy analyst with 40 years' experience in energy economics, policy, and ratemaking issues. At TCR Mr. Hornby provides consulting services, litigation support, and expert testimony on electric industry planning, market structure, and ratemaking issues. He is focusing on issues associated with the transition to cleaner sources in wholesale energy markets and to the utility of the future at the distribution level. Representative projects include analysis of market design and pricing required to implement a new distribution level market for electric products from distributed energy resources and traditional resources; development of long-term projections of avoided electricity and natural gas costs in New England; and assessment of the impact of offshore wind on wholesale energy prices on Long Island.

Mr. Hornby's clients have included utility regulators, efficiency program administrators, consumer advocates, environmental groups, state energy and environmental policy makers, power and transmission project developers, energy marketers, gas producers, and utilities throughout the United States and in Canada. He has provided expert testimony and litigation support on numerous electricity and natural gas issues in over 125 regulatory proceedings and contract arbitration cases in more than 30 states and provinces. He has testified on the value of distributed energy resources; utility proposals for smart grid and smart meter investments; proposals for dynamic pricing and other time varying rates; proposed acquisitions of generating assets; ratemaking proposals to better align utility financial incentives with aggressive pursuit of energy efficiency, including the Duke Energy "save-a-watt" proposal; unbundling electricity and natural gas retail services and rates; and procurement of natural gas supplies and pipeline capacity.

Prior to joining TCR, Mr. Hornby was a senior consultant at Synapse Energy Economics and at Tabors Caramanis & Associates. Previously he was director of the energy practice at Tellus Institute, assistant deputy minister of energy for the province of Nova Scotia, and a project engineer responsible for energy management programs in industry.

MS, Technology and Policy (Energy), Massachusetts Institute of Technology

BE, Industrial Engineering, Dalhousie University

Hank He, Associate

Hank is a chemical engineer with over 5 years' experience in the energy industry. At TCR, Hank provides support on market design, asset valuation and litigation issues for a variety of power market stakeholders. Areas of expertise includes generation and transmission valuation, ancillary services studies, renewable integration, resource adequacy, and many others.

Experienced user of Enelytix platform for energy and antically service market simulation, capacity market modeling and long-term resource planning. Developed and tested nodal market simulation model for multiple North American electric markets. Highly proficient in Python, SQL server and Visual Basic.

Master of Engineering Management, Dartmouth College, Hanover, NH
B.S Chemical Engineering, Lafayette College, Easton, PA

Ninad Kumthekar, Senior Analyst

Ninad Kumthekar is a mechanical engineer with 5 years' experience in the energy industry. He specializes in the modelling and analysis of thermal power generation systems and has a good understanding of the technical fundamentals underlying various power generation, transmission and desalination technologies. He has been part of multidisciplinary project teams delivering technical advisory, engineering consultancy and design services to developers, regulatory bodies, lenders and electricity utilities in the Middle East. More recently, he has gained exposure to the United States through projects dealing with the with the design and operation of electricity market focusing on the integration of clean energy into the New England system.

Mr. Kumthekar is skilled in spreadsheet modelling and has developed models for emission forecasting, fuel demand modelling, subsystem design optimizations, and project life cycle cost analyses. He is proficient at thermal modelling using proprietary software and has undertaken design reviews, feasibility studies and assisted in the development of technical bids. He is conversant in visual basic and C programming languages and uses R and MATLAB to undertake more complex data manipulation and statistical analysis tasks.

At TCR, Mr. Kumthekar assists in delivering TCRs evaluations of clean energy project bids for utilities in the New England region. He has been closely involved with the development, testing and implementation of the capacity expansion module in ENELYTIX and supports TCRs power market modelling analysis through database curation, market research and data analysis. Prior to TCR, he worked as a project engineer with the UK based engineering consulting firm, Mott MacDonald, with their power generation team in Abu Dhabi

Master of Engineering Management, Dartmouth College
BTech, Mechanical Engineering, National Institute of Technology (Surat), India

Xindi Li, Senior Analyst

Xindi Li is a mechanical engineer with expertise in the simulation and analysis of electric power and natural gas markets. At TCR Ms. Li simulates electric power markets using ENELYTIX, a state-of-the-art optimization model. She assembles and analyzes market data to support TCR projects on asset valuation, resource adequacy and market operation. Ms. Li is responsible for simulating natural gas pipeline operation at both the physical and market level using transient pipeline network optimization software. She develops and manages procedures for automating the provision of network data and results analytics to support pipeline simulations both in autonomous mode and for modeling coordination of gas and electric markets.

MS, Mechanical Engineering, Rice University
Bachelor of Engineering, Power System and Energy Engineering, Southeast University