Appendix A1. Factor Inputs

1 Purpose

The purpose of this appendix is to identify key input assumptions and data used in the electric system simulation modeling for the Clean Energy Pathways Study (Study) for each of the 10 scenarios tested.

2 Regional Electric System Modeling Approach and Software Tools

The Study used the zonal version of Aurora, a production cost and capacity expansion optimization chronological simulation model licensed from Energy Exemplar, for long-term capacity planning and hourly commitment and economic dispatch of resources. The default database provided by Energy Exemplar served as an initial foundation. Energy Exemplar's database has been extensively customized based on public data sources, proprietary calculations, and professional judgment.

3 Study Period, Base Weather Year, and Time Steps

Modeling was conducted for a 20-year period, from 2021 to 2040. The planning horizon corresponds to the endpoint of Governor Lamont's Executive Order directing DEEP to study meeting 100% of power generation needs with clean energy.

Given the importance of weather-based coincident relationships among load, solar energy, and wind energy under increased penetration of variable energy resources (VERs), coincident hourly load, solar PV output, and wind output profiles were used. To ensure correct correspondence between hourly load and VER generation, a common historic weather year was used for the load and VER generation profiles. First, load data was analyzed for 2007 through 2012, the years for which NREL data is available for hourly wind and solar PV output profiles. Then, year 2011 was selected as the most representative year based on being most typical as measured by deviations from average monthly energy demand and summer and winter hourly peak loads over the six years.

Capacity expansion and retirement decisions were made in Aurora. Both capacity expansion and retirement decisions are performed annually. Production cost simulations were conducted using all-hours chronological dispatch.

4 Scenarios

The 10 scenarios examined in this study, listed in Table 1. The Composition of Scenarios are the union of two load cases and five integrated resource portfolio cases. Each of the resource portfolio cases requires more resources to satisfy demand and reserve requirements in the higher Electrification load case than for the Base load case. More detail on the Resource Portfolio Cases and Gross Load Cases is provided later in this appendix. In addition, as discussed in more detail in section 6.2, the Electrification load case projected more energy efficiency for weatherization measures than the Base load case to facilitate its higher ASHP deployment for space conditioning.

Table 1: Composition of Scenarios

Scenario	Gross Load Case	Resource Portfolio Case
BR	Base	Reference (current policies)
BB		Balanced Blend
BS		Solar BTM PV Emphasis
BM		Millstone PPA Extension
BT		Transmission
ER	Electrification	Reference (current policies)
EB		Balanced Blend
ES		Solar BTM PV Emphasis
EM		Millstone PPA Extension
ET		Transmission

This Study also considered the implementation of a carbon tax, in addition to RGGI carbon allowance prices, on fossil-fueled generation in Connecticut. This analysis is considered a separate sensitivity from the other scenarios as it was only tested in one year. The findings of the carbon tax analysis are in Appendix 4.

5 Study Region, Sub-areas, and External Interfaces

Aurora was run in a zonal configuration with the Study Region restricted to ISO-NE. ISO-NE was divided into the 13 sub-areas identified in the Regional System Plan (RSP). Maine state-wide data for electric vehicle (EV) and air source heat pump (ASHP) loads were reduced to only include the portion of their loads within the ISO-NE region.[1]

Power import (and export) flows with other regions (NYISO, Quebec, New Brunswick) over existing transmission lines were modeled based on an average weekly profile for each month using three years of historical flow data (168 hours by 12 months). This multi-year average weekly shape approach used 2017-2019 flows.

New Canadian hydro and wind resources imported over new HVDC transmission ties were modeled as integrated generation plus transmission projects in the set of potential generation resources.

5.1 Transmission Transfer Limits

Inter-zonal transmission transfer limits were defined using publicly available data sources. The primary source for transfer limits within ISO-NE was the Forward Capacity Market (FCM)

[1] ISO-NE load forecasts do not include the Northern Maine ISA in projections and therefore did not require any adjustments.

Capacity Commitment Period Tie Benefits Study Assumptions, augmented by several smaller adjustments per other sources, as noted below.[2]

Figure 1: ISO-NE Transmission System Representation[3]

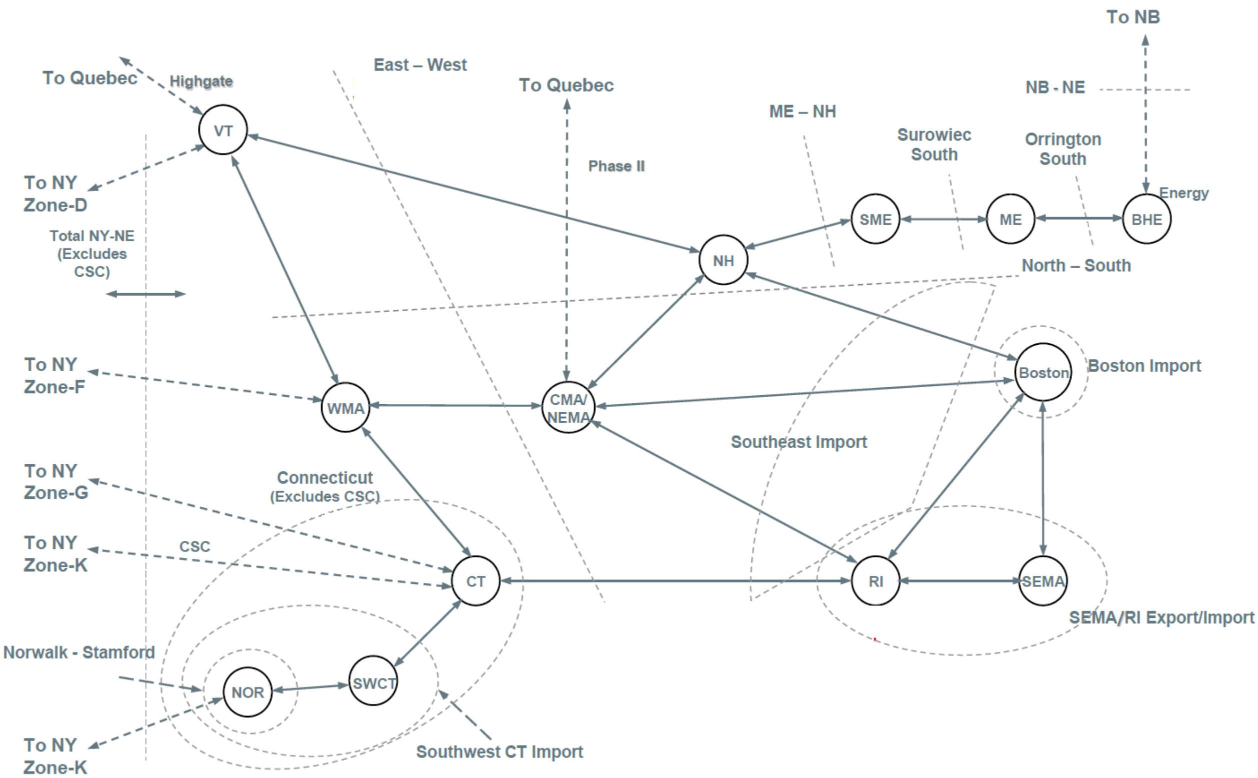


Table 1: ISO-NE Internal Interface Transfer Capabilities (MW)[4]

[2] Quan Chen, ISO-NE, "2023-2024 Capacity Commitment Period Tie Benefits Study Assumptions". Presented May 30, 2019 to the Power Supply Planning Committee. https://www.iso-ne.com/static-assets/documents/2019/05/a62_fca14_tie_benefits_assumpts_05302019.pdf

[3] *Id.*

[4] Import interfaces are modeled at (N-1) capability.

Interface	2020	2021	2022	2023	2024+
Orrington South	1,325	1,325	1,325	1,325	1,325
Surowiec South	1,500	1,500	1,500	2,500[5]	2,500
Maine – New Hampshire	1,900	1,900	1,900	1,900	1,900
North – South	2,725	2,725	2,725	2,725	2,725
East – West	3,500	3,500	3,500	3,500	3,500
Boston Import	5,400	5,700	5,700	5,700	5,150[6]
SEMA/RI Export	3,400	3,400	3,400	3,400	3,400
SEMA/RI Import	1,280	1,280	1,280	1,800	1,800
SENE Import	5,400	5,700	5,700	5,700	5,150[7]
Connecticut Import	3,400	3,400	3,400	3,400	3,400
SWCT Import	2,800	2,800	2,800	2,800	2,800

6 Demand Projections

6.1 Conventional Gross Demand

The Study used ISO-NE's 2019 Capacity, Energy, Loads, and Transmission (CELT) Report as the basis for annual and monthly peak hour and average energy demand projections. CELT load forecasts span ten years; the 2019 CELT Report runs through 2028. The load forecast was extrapolated at different rates for energy and for summer and winter peak demand, as these respective parameters have different forecasted growth rates in the CELT report. The extrapolation for conventional gross energy for load and summer and winter peaks followed exponential growth curves based on each respective RSP subarea projection's combined annual growth rate (CAGR).[8]

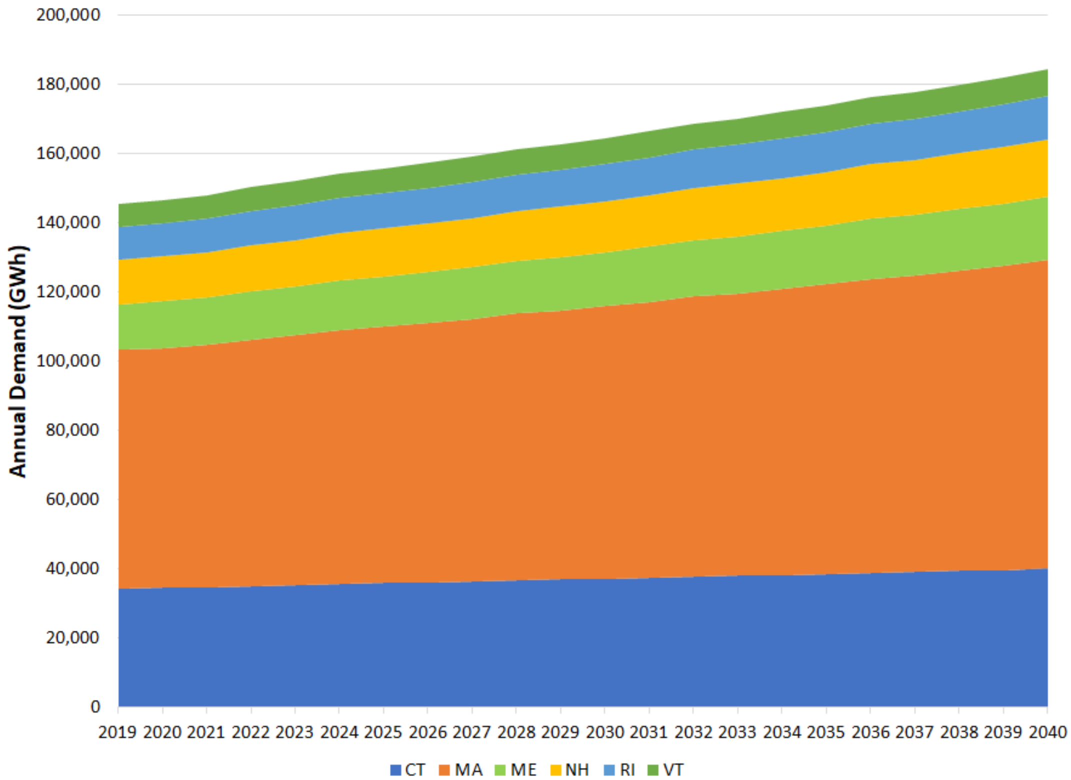
Figure 2: Gross Load Projections by State

[5] Surowiec South transfer limit increased due to inclusion of NECEC and associated upgrades per ISO-NE Economic Study. See Patrick Boughan, ISO-NE, "NESCOE 2019 Economic Study – 8,000 MW Offshore Wind Results", Presented at February 20, 2020 Planning Advisory Committee Meeting. https://www.iso-ne.com/static-assets/documents/2020/02/a6_nescoe_2019_Econ_8000.pdf

[6] SENE and Boston Import capabilities were updated due to Mystic 8/9 retirement for FCA 15, per ISO-NE materials. See Al McBride, ISO-NE, "Updated Southeast New England and Boston Import Transfer Capabilities: Capacity Commitment Period 2024-25", Presented at February 20, 2020 Planning Advisory Committee Meeting. https://www.iso-ne.com/static-assets/documents/2020/02/a5_bos_imp_trans_update.pdf

[7] *Id.*

[8] Detailed forecast data was sourced from ISO-NE's web site: https://www.iso-ne.com/static-assets/documents/2019/04/forecast_data_2019.xlsx



The gross load projection, independent from EV and ASHP demand, remains constant between the two Load Cases. ISO-NE's 2019 CELT report forecasted a gross load CAGR of 0.8% for Connecticut, compared to 1.1% for ISO-NE at large.

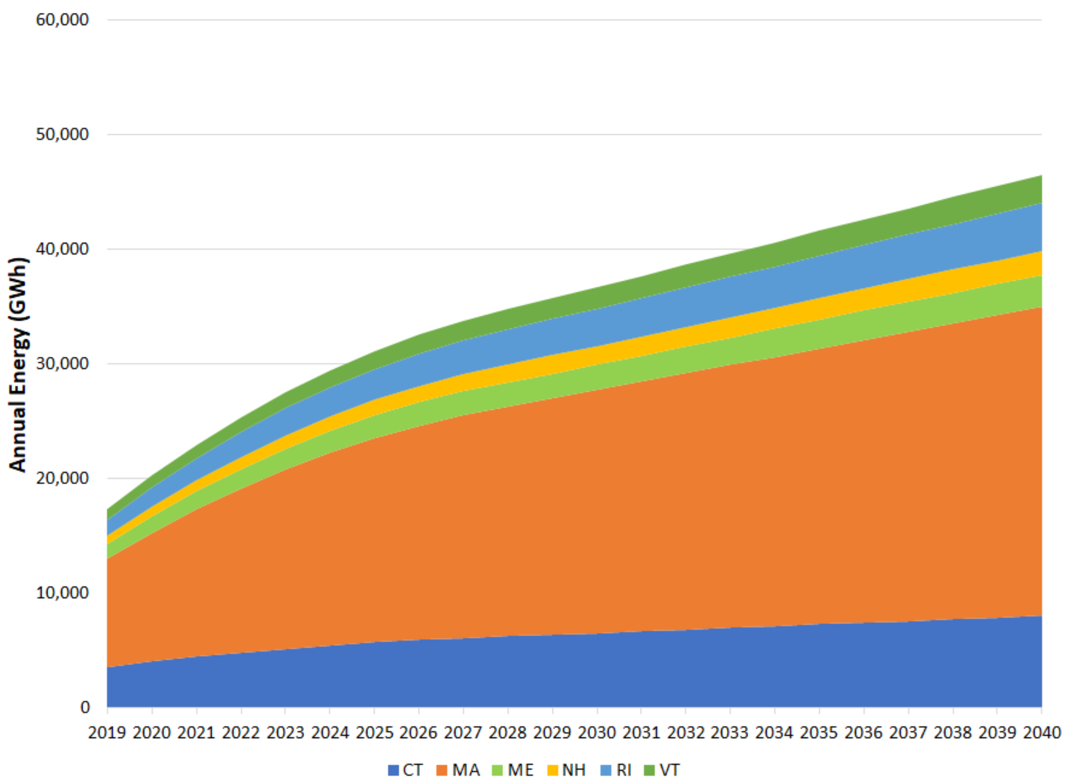
6.2 Energy Efficiency Projections

Energy Efficiency (EE) projections differ between the Base and Electrification load cases. EE projections also used the 2019 CELT forecast as a starting point and extrapolated beyond 2028 with a constant MW growth rate per 2028's forecasted growth. The Base load case applied only this CELT-based projection, while the Electrification load case included additional EE savings to reflect incremental weatherization measures to accommodate ASHP growth without degradation of ASHP performance. As observable in Figure 3, EE grows much more slowly from 2027 on than for 2019 to 2027 because the 2027 to 2028 change basis for the extrapolation period was less than in prior years of the CELT forecast. The average annual rate of growth of EE from 2019 to 2028 in the Base load case is 8.06%, dropping to 2.45% for 2028 to 2040.

It is beyond the scope of this Study to formulate a basket of EE measures or programs for the assumed continued growth in EE to support the linear extrapolation assumption. Undoubtedly, as current EE programs, such as for LED lighting, reach saturation, other technologies, such as smart appliances or new materials for building insulation, will begin to be adopted as they become more technically proven and cost-effective. However, it is useful to compare the assumed EE projection for New England with that for New York. The NYISO 2020 Gold Book makes forecasts from 2019 through 2050. The Gold Book includes Baseline, Low Load, and High Load scenarios. For EE, the Baseline scenario assumes "substantial attainment of current policy measures," while the

Low Load and High Load scenarios assume "full" and "low" attainment, respectively.[9] For 2019 to 2028, the Gold Book assumes that EE grows by an average annual rate of 7.39% from 2019 to 2028, and by 1.74% from 2028 to 2040 in its Baseline Load scenario. For comparison, the 2020 Gold Book also includes the Climate Leadership and Community Protection Act (CLCPA) load forecast from the NYISO *Climate Change Impact Study Phase I* report of December 2019. The EE average annual rates of growth in the CLCPA case are 10.56% for 2019-2028 and 2.41% for 2028 to 2040. The CLCPA EE forecast is slightly more aggressive than this Study's Base Load case projection, and NYISO's Baseline EE forecast is slightly less aggressive.

Figure 3: Energy Efficiency Projections by State, Base Load Case



Almost all ASHP installations have their energy and demand savings reported to ISO-NE by EE program administrators. Increasing ASHP penetration to a high percentage of all homes will require additional weatherization to allow for efficient heat pump operation. The current amount of EE savings attributed to weatherization-related measures was assumed to double in the Electrification load case.

The additional weatherization savings in the Electrification EE projection is likely to be cost-effective. Data from the U.S. Department of Energy (DOE) in 2015 showed that every $1 invested

[9] NYISO, *2020 Load & Capacity Data* (Gold Book), p. 11.

in weatherization generates $1.72 in energy benefits and $2.78 in non-energy benefits.[10] An earlier report examined the benefit cost ratios of weatherization and found that "[weatherization] has a benefit cost ratio of about 1.4 for energy savings. And when energy, health, and safety benefits are incorporated the benefit cost ratio rises to 4."[11] After the Oak Ridge National Laboratory conducted multiyear, peer-reviewed, statistically robust evaluations of the Weatherization Assistance Program, the DOE concluded that "Weatherization provides cost-effective energy savings to American families, provides additional health and safety benefits, supports jobs, and provides a stable platform for additional investment in energy efficiency."[12] The final doubling of annual weatherization EE savings in the Electrification load was linearly ramped up over the first three years of the Study Period, 2021 to 2023.

Incremental weatherization EE by state was calculated via a two-step procedure:

> **Step 1.** Annual energy savings and peak demand reductions in the Connecticut Utilities 2019 CL&M Plans expected for various EE programs in 2020, 2021, and 2022 (Table B on pages 328, 330, 332) were reviewed. Weatherization-related EE programs (Home Energy Solutions and HES Income Eligible programs) constitute, on average, about 14% of total energy savings and 16% of total peak demand reduction for all classes of consumers.
>
> **Step 2**. These three-year average percentages were applied to the PDR on Energy and PDR on Peak, respectively, derived from ISO-NE's 2019 CELT forecast by state for 2019-2028 (Tab 12 FC) and calculated annual weatherization energy savings and weatherization peak reduction by state for 2019 to 2028.[13] The CELT data was used for this Study's Base load case. Since weatherization EE is already embedded in the CELT forecast, no additional weatherization EE is included in the Base load case load projections. In the Electrification load case, each state's weatherization annual energy and peak demand EE savings are doubled.

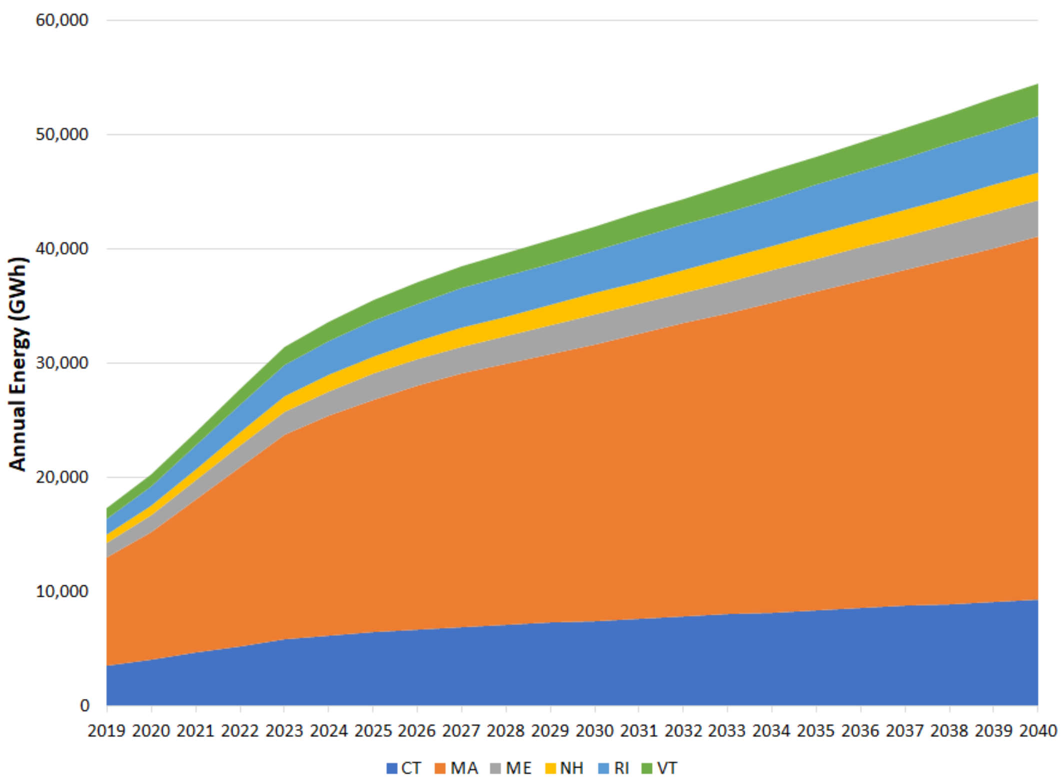
Figure 4: Energy Efficiency Projections by State, Electrification Load Case

[10] U.S. Dept. of Energy, Office of Energy Efficiency and Renewable Energy, "Weatherization Works!", February 2018. See: https://www.energy.gov/sites/prod/files/2018/03/f49/WAP-fact-sheet_final.pdf

[11] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, "Getting It Right: Weatherization and Energy Efficiency are Good Investments", August 10, 2015. https://www.energy.gov/eere/articles/getting-it-right-weatherization-and-energy-efficiency-are-good-investments

[12] U.S. Department of Energy Office of Energy Efficiency and Renewable Energy, "Weatherization Assistance Program National Evaluations: Summary of Results," August 2015. https://www.energy.gov/sites/prod/files/2015/08/f25/WAP_NationalEvaluation_WxWorks_v14_blue_8%205%2015.pdf

[13] PDR is an abbreviation for Passive Demand Response.



6.3 BTM Solar PV Projections

Behind-the-meter (BTM) solar PV, which is also included in the 2019 CELT report, is deducted after load net of EE is calculated in order to reflect the changes to hourly shape of net load that solar PV creates as BTM PV capacity grows over time, and at different rates in the BTM PV Emphasis cases relative to the other resource portfolios. Three BTM Solar PV projections have been developed for use in the resource cases:

- The Reference resource portfolio cases use a smaller capacity schedule of BTM solar PV.
- The decarbonization resource cases other than the BTM Emphasis cases use a more aggressive capacity schedule of BTM solar PV than has been tested in current ISO-NE planning documents.
- The BTM Emphasis portfolios use a more aggressive capacity expansion schedule of BTM solar PV than the other decarbonization cases.

The growth rate (MW/year) in Connecticut, shown in Table 3, is provided as an average over the 20 year modeling horizon and is not linear, as shown by Figure 5, Figure 6, and Figure 7. The Reference resource portfolio cases assumed that BTM solar PV resource capacity will follow a constant MW growth rate per the 2028 annual expansion rate. Incremental BTM solar growth in the decarbonization portfolios considered available households for BTM solar as a proxy for rooftops, which led to more BTM growth in populous states relative to the 2019 CELT forecast.

Table 2: Connecticut BTM Growth, Resource Case Comparison

Resource Case	BTM PV Energy (GWh)	BTM PV Growth (MW/year)
Reference	2,077	51
BTM Emphasis	4,189	126
Other Cases	2,710	74

Figure 5: BTM PV Projections by State, Reference Resource Case

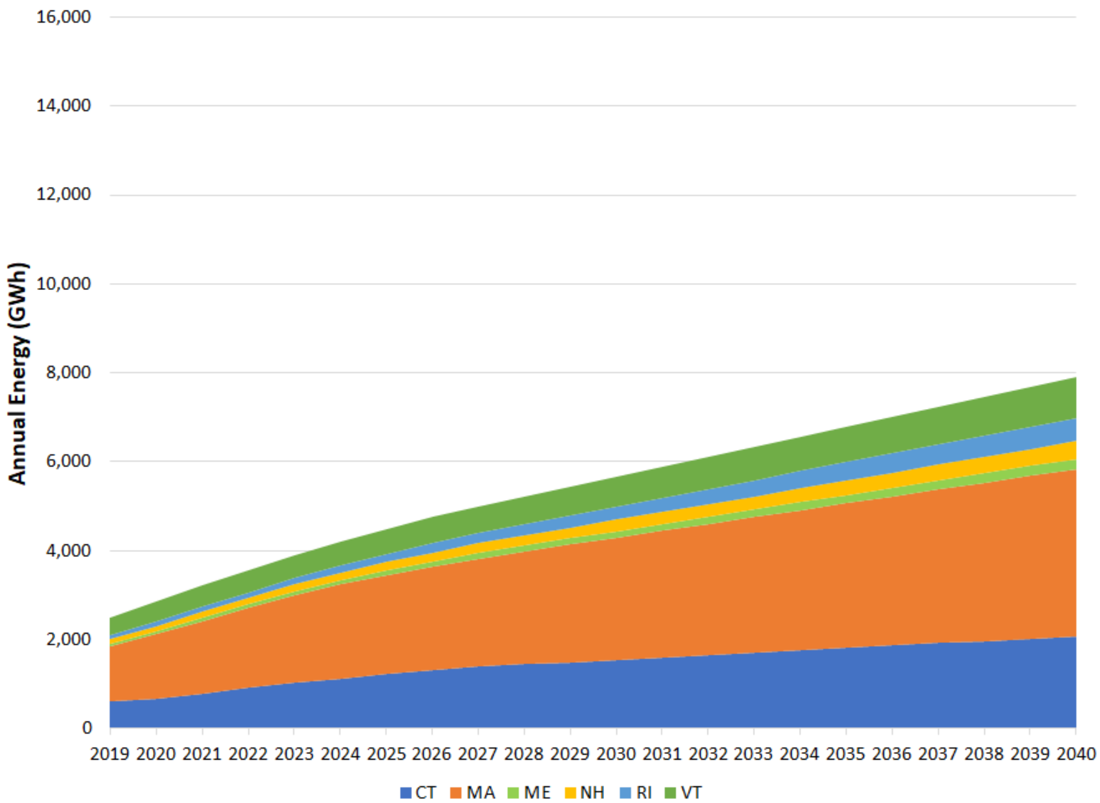


Figure 6: BTM PV Projections by State, BTM Emphasis Resource Case

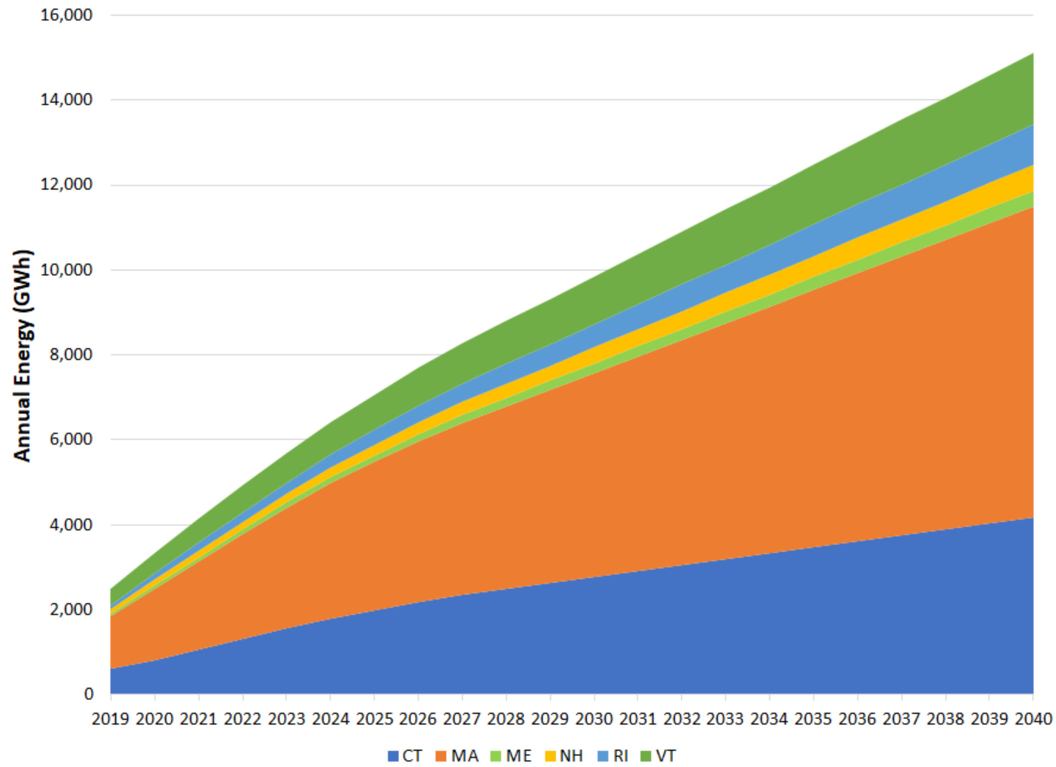
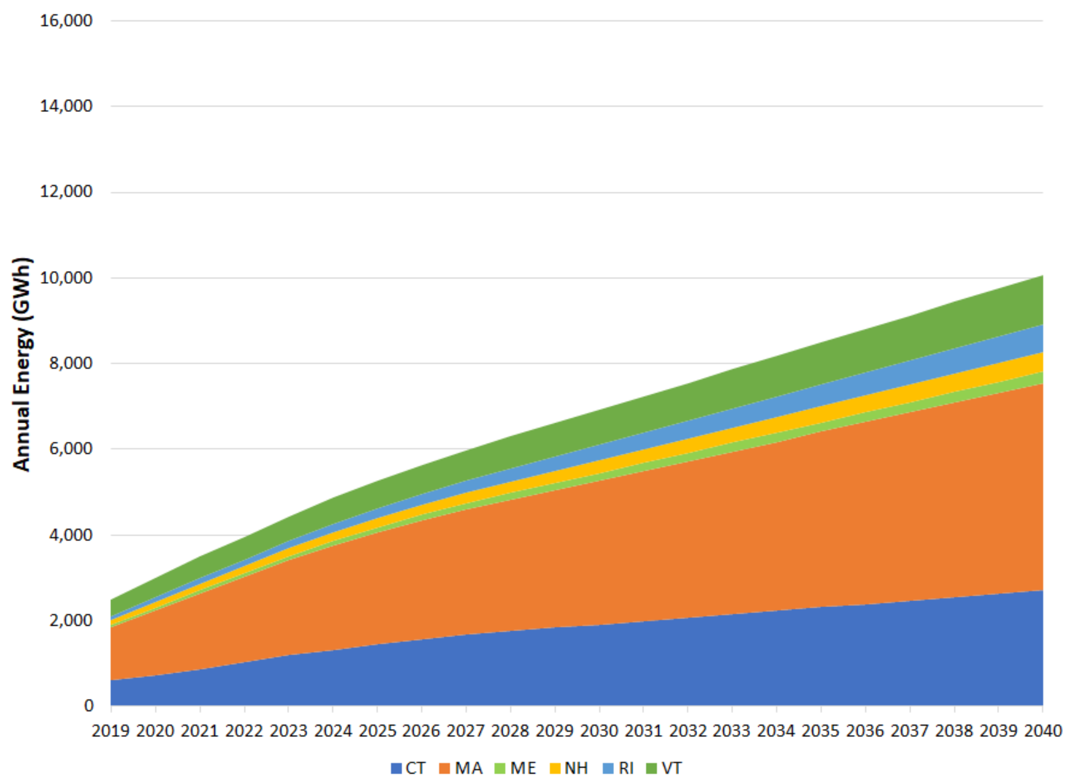


Figure 7: BTM PV Projections by State, Other Resource Cases



6.4 Electric Vehicles Demand Projections

6.4.1 Electric Vehicle Sales and Stock

The Base load case assumption for penetration of Electric Vehicles (EVs) followed the proposed method presented by ISO-NE's Load Forecast Committee in its September 27, 2019 "Transportation Electrification Forecast Update" and December 20, 2019 "Draft 2020 Transportation Electrification Forecast" presentations. Electrification of the transportation sector was limited to electrification of light-duty vehicles (LDVs) in both the Base and Electrification load cases. Light-duty electric vehicles (LDEVs) include Battery Electric Vehicles (BEVs) and Plug-in Hybrid Electric Vehicles (PHEVs). Data on the stocks of both BEVs and PHEVs in 2018 were obtained from the Alliance of Automobile Manufacturers 2018 LDV registrations. Projected annual sales of BEVs and PHEVs for years 2019 through 2029 reflect the EIA's 2019 AEO reference case regional forecast for New England.[14] For those years, the annual forecast of LDEVs for the New England region was allocated to each state based on its 2018 share of EVs relative to all New England states. Table 3 summarizes this initial stock data.

Table 3. Electric Vehicles 2018 Stocks and Regional Share by State

State	Total LDEV Registrations Stocks	State Share of New England Region
CT	9,799	23.7%
MA	21,258	51.4%
ME	2,529	6.1%
NH	3,099	7.5%
RI	1,738	4.2%
VT	2,926	7.1%
Total	**41,349**	**100%**

Following the method outlined above for the remaining years yields LDEV sales penetration rates ranging from 7.5% to 16% in 2040. The AEO annual EV sales forecast represents a much more conservative outlook of EV sales penetration rates than many other studies have shown, including the ongoing Transportation Climate Initiative (TCI) reference case results.[15] It was assumed that LDEV sales penetration rates will grow steadily beyond the end of the CELT forecast 2029 horizon. Instead of applying the AEO sales forecast beyond 2029, LDEV sales penetration rates

[14]Annual forecasted BEVs is the sum of all forecasted 100-mile, 200-mile, and 300-mile electric cars and light trucks and PHEVs is the sum of Plug-in 10 and 40 Gasoline Hybrid cars and light duty trucks.

[15] Data provided by TCI consultant OnLocation support a forecasted 2040 energy demand of 14,144 GWh for the New England footprint, whereas following the methodology used in the CELT forecast through 2040 implies only 3,320 GWh in 2040.

in each state in 2040 were assumed to be 10% higher than the statewide 2029 LDEV sales penetration rate.[16]

LDEVs were assumed to have an average useful life of 11 years in both the Base and Electrification load cases. Therefore, each LDEV was removed from the vehicle stock after 11 years.[17] For PHEV stock as of 2018, the vehicles were phased out at 20% of the 2018 PHEV stock per year from 2026 to 2030. For BEV stock as of 2018, the vehicles were phased out at 50% in 2028 and 50% in 2029. The reason for this difference is that PHEVs were a larger proportion of the LDEV stock as of 2018 and it some of those PHEVs are older than the BEVs in the fleet.

For the Electrification load case, a review of studies on deep decarbonization of the transportation fleet was conducted to determine an achievable level of EV penetration in 2040. Annual sales of LDVs were projected through 2040 by state applying the 20-year compound average growth rate of LDV sales in the US reported by FRED to each state's 2018 LDV sales.[18] The annual electric vehicle sales distribution between BEVs and PHEVs was based on the projected sales of LDEVs in New England from the 2019 AEO Reference Case. Consistent with existing literature, the share of LDEV sales that are BEVs grows over the Study Period, reaching 80% of annual LDEV sales by 2040, and PHEV sales decline to 20% of annual LDEV sales.[19] LDEV penetration rates were assumed to grow more slowly during the early years of the Study Period and then ramp up from 2025 to 2040. A generalized logistic function was applied to set the annual level of LDEV sales in each state to capture the expected rapid adoption of LDEVs earlier in the Study Period, and then slows as the market nears saturation. LDEV penetration rates were expected to reach higher percentages of total LDV sales in Connecticut, Massachusetts, and Vermont relative to the other New England states. This is due to the participation of these three states in the multi-state MOU on zero emission vehicles (ZEVs). Annual new LDEV sales penetration rates in 2040 for each state and the two electric load cases are shown in Table 4.

Table 4. LDEV New Sales Penetration Rate in 2040

State	Base Load Case	Electrification Load Case
CT	19%	60%
MA	20%	68%
ME	16%	59%
NH	16%	52%

[16] The 10% growth from the 2029 LDEV sales penetration to 2040 was interpolated linearly.
[17] The 2018 state fact sheets from the Alliance of Automobile Manufacturers that contained the LDV registrations also provide the average life of an LDV in that state. Average LDV life in New England was about 11 years.

[18] Federal Reserve Bank of St. Louis Economic Database (FRED), ALTSALES data series.

[19] The AEO data series on LDEV sales downloaded from https://www.eia.gov/outlooks/aeo/data/browser/#/?id=48-AEO2019&region=1-1&cases=ref2019&start=2017&end=2040&f=A&sourcekey=0

RI[20]	16%	85%
VT	21%	61%

The Connecticut GC3 plan provided the foundation for the state's annual energy demand in the Electrification load case.[21] For Connecticut, more aggressive growth in EV penetration was incorporated in the Electrification case to include not only stronger LDV fleet electrification but also electrification of the heavy-duty vehicle (HDV) fleet that includes busses and heavy transport trucks. Annual energy demand for Connecticut between 2020 and 2030 reflects the forecasted energy demand from the GC3 Plan with the exception that the annual energy demand between 2020 and 2025 is smoothed to reflect the current state of the market.[22] Annual LDEV sales were projected using the same method used to project annual LDEV sales throughout New England. Annual LDEV sales in Connecticut reach 60% by 2040. Starting in 2025, HDEVs were expected to make up a share of the annual energy demand in Connecticut. HDEV energy demand covers the portion of projected total EV energy demand beyond the LDEV demand from 2025 through 2030, after which HDEV annual energy demand was projected to grow by 7.5 percent each year.

6.4.2 EV Daily and Annual Demand

Daily average energy usage per EV as reported on slide 9 of the December 20, 2019 ISO-NE Draft 2020 Transportation Electrification Forecast presentation was used as the foundation of the annual energy demand from BEVs and PHEVs in this Study. The data reflect observed charging behavior in New England provided to ISO-NE by Chargepoint. From these data, a vehicle weighted-average charging energy of 3,809 kWh per year was calculated. A 2017 Argonne National Laboratory (ANL) study provided energy consumption levels of 2,500 kWh per year for PHEVs and 3,500 kWh annually for BEVs.[23] The monthly charging energy provided by ISO-NE did not specify what types and quantities of LDEVs were included in the sampled data. Because the ANL BEV annual energy demand was similar to the ISO-NE aggregated Chargepoint data, the annual average energy consumption for BEVs in this Study was set to 3,809 kWh. For PHEVs, the annual BEV demand was scaled down by a factor of 0.714 to determine the annual average annual energy consumption of PHEVs.[24] Table 5 provides the average daily charging energy by month used in this Study for BEVs and PHEVs.

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[20]The Electrification load case for RI reflects values provided for use in this Study by the RI Office of Energy Resources.

[21] "Building a Low Carbon Future for Connecticut: Achieving a 45% GHG Reduction by 2030: Recommendations from the Governor's Council on Climate Change." December 18, 2018. https://ctclimateandjobs.org/wp-content/uploads/2019/11/Building-a-Low-Carbon-Future-for-CT_GC3-Recommendations.pdf

[22] Since the GC3 Plan was published in 2018, annual energy demand from EVs early in the Study Period reflect values that would require more annual sales of EVs in 2020 than reasonable. Therefore, annual energy demand from EVs is smoothed to reflect actual 2018 energy demand and forecasted energy demand in 2025.

[23] David Gohlke and Yan Zhou, Argonne National Laboratory Energy Systems Division. "Impacts of Electrification of Light-Duty Vehicles in the United States, 2010-2017." https://publications.anl.gov/anlpubs/2018/01/141595.pdf

[24] The factor 0.714 is the ratio of the PHEV to BEV charging demand from the ANL study.

Table 5. ISO-NE Average Daily LDEV Charging Energy

Month	Average Daily BEV Charging Energy (kWh)	Average Daily PHEV Charging Energy (kWh)
Jan	12.1	8.6
Feb	11.4	8.1
Mar	11.5	8.2
Apr	10.8	7.7
May	10.1	7.2
Jun	9.2	6.6
Jul	8.4	6.0
Aug	9.0	6.4
Sep	9.4	6.7
Oct	10.9	7.8
Nov	11.3	8.1
Dec	11.2	8.0
Annual	***10.4***	***7.5***

In 2019, LDEV penetration in New England accounted for just one percent of the total LDV stock and 367 GWh of annual demand. Under the Base load case assumptions, LDEV penetration in New England reaches 9% of total LDV stock and approximately 4,417 GWh of annual demand in 2040. Base load case LDEV penetration in Connecticut reaches 9% of the total LDV stock and accounts for nearly 1,006 GWh of annual demand in 2040. Under the Electrification load case assumptions, LDEV penetration in New England reaches 37% and around 19,561 GWh of annual demand in 2040. The Electrification load case LDEV penetration in Connecticut reaches 35% of the total LDV stock and about 6,388 GWh of annual demand in 2040.

6.4.3 EV Charging Profiles

For the Base load case, 8760 fixed charging profiles were developed for LDEVs that reflect aggregated charging behavior in New England. These profiles differentiate the daily charging regime by month and whether it is a weekday or weekend/holiday, thereby accounting for seasonality issues associated with expected EV charging patterns. Both weekday and weekend charging profiles reflect aggregated residential (78%) and non-residential (22%) charging demand. The modeled profiles were adapted from aggregated Chargepoint data presented by ISO-NE in two Load Forecasting Committee meetings. Weekday profiles for each month were adapted from the curves presented on slide 13 of the December 20, 2019 "Draft 2020 Transportation Electrification Forecast." Weekend profiles for each month were adapted from the 50th percentile of the box plots presented in the November 18, 2019 "Update on the 2020 Transportation Electrification Forecast" presentation. As proposed in the December 20 presentation, monthly energy demand reflects a 6% gross up to account for transmission and distribution losses.

For the Electrification load case, it was anticipated that charging behavior will need to become smarter over time to mitigate EV contribution to system peak load. Thus, EV charging demand was modeled dynamically using Aurora's storage resource logic. This approach allowed for vehicle charging up to a specified maximum rate during hours designated for vehicle charging as described in the following section and shown in Table 9.

Figure 8: EV Projections by State, Base Load Case

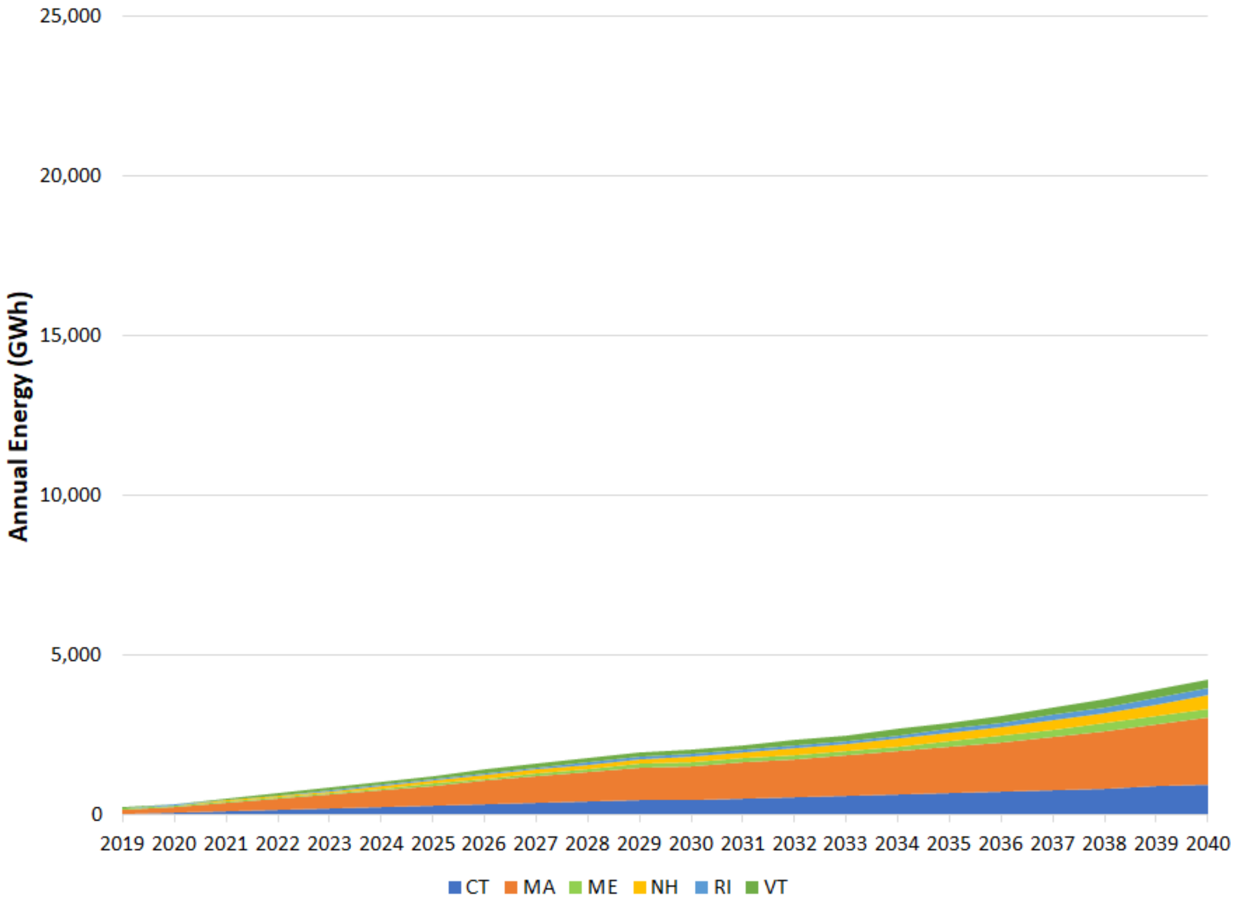
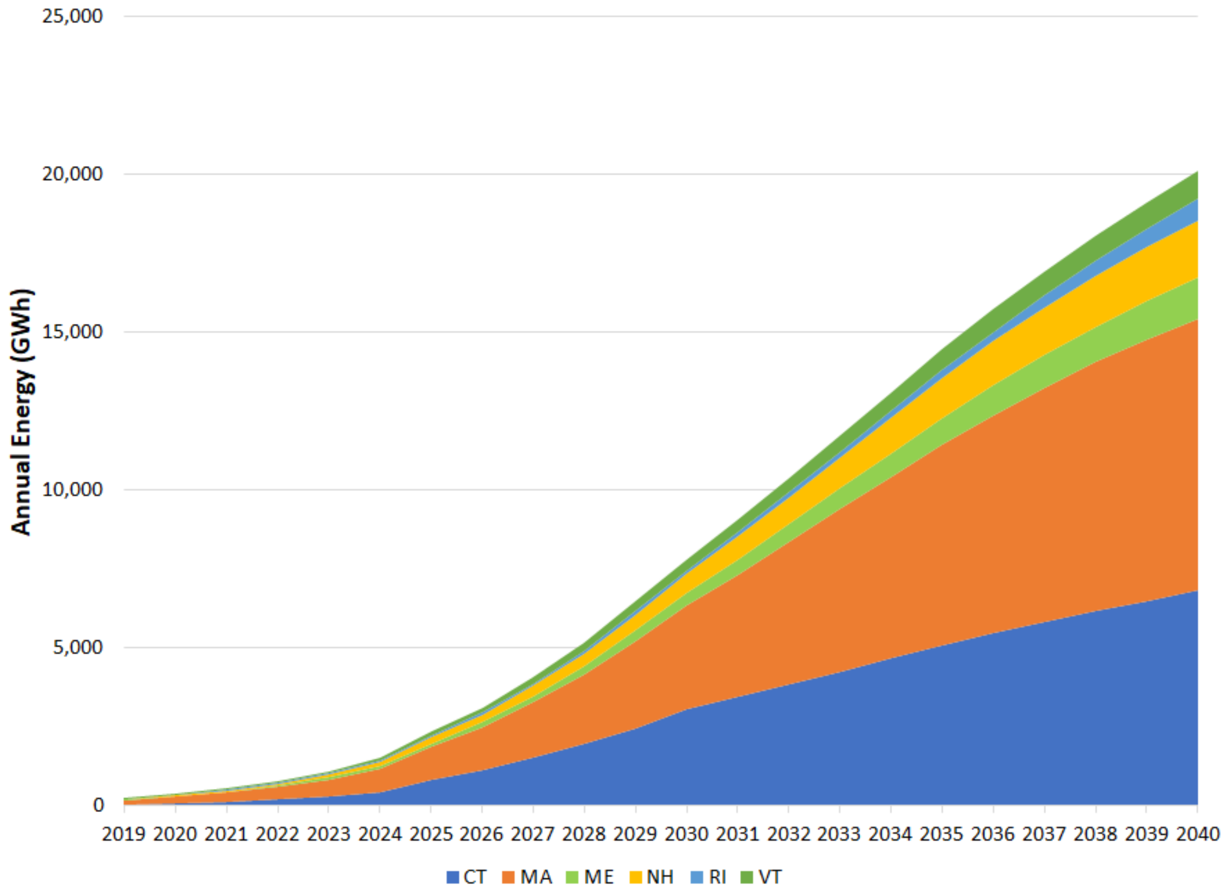


Figure 9: EV Projections by State, Electrification Load Case



6.4.4 Electrification charging regime

For the Electrification load case, EV energy demand incremental to the Base load case EV energy demand was modeled as flexible demand. It is anticipated that such increases to future load as those contemplated in the Electrification load case will necessitate shifting EV energy demand so that it can be responsive to market price and demand signals.

The amount of EV energy demand from the Base load case was modeled using the same 8760 fixed energy demand profiles. Incremental EV energy demand was broken out into six potential charging categories to capture different charging availability throughout the day: residential level 1 (RL1), residential level 2 (RL2), work level 1 (WL1), work level 2 (WL2), public level 2 (PL2), and public direct fast charging (PL3). Level 1, level 2, and level 3 chargers deliver different average amounts of power per hour and depending on whether the vehicle is a BEV or PHEV as shown in Table 6.

Table 6. Power Delivered (kW/h) by Charging Category and EV Type[25]

Charging Category	BEV	PHEV
Level 1	1.4	1.4
Level 2	6.2	3.6
Direct Current Fast Charging (Level 3)	50.0	-

For BEVs, the distribution of incremental EV charging demand across the six categories was based on an NREL charging infrastructure study that provided a breakdown of charging demand by location and level of charging and a McKinsey & Company study that provided a breakdown of charging by level only.[26,27] The distribution across the charging categories was expected to change toward a higher level of access to faster charging over the Study Period as shown in Table 7 below.

Table 7. Distribution of BEV Charging Energy Demand Across Six Charging Categories

Charging Category	2020	2030	2040
RL1	33%	11%	5%
RL2	44%	50%	53%
WL1	3%	0%	0%
WL2	5%	6%	6%
PL2	13%	15%	16%
PL3	2%	19%	20%

For PHEVs, the distribution of incremental EV charging demand was spread across just five categories because PHEVs are not equipped to receive power at rates higher than 3.6 kW per hour, *i.e*. no PL3 charging and reduced charging rates for L2 charging. PHEV charging breakdown did not change over time as PHEVs charge in the home 88% of the time.[28] PHEVs cannot receive (nor do they need to) as much power per hour as a BEV, therefore it was assumed that L1 charging predominates home charging at a ratio of 3:1. The 12% of charging that happens away from home was allocated evenly to the three categories.

[25] NREL, "Meeting 2025 Zero Emission Vehicle Goals: An Assessment of Electric Vehicle Charging Infrastructure in Maryland". February 2019, p. 16.

[26] Matteo Muratori and Eric Wood, "Charging Infrastructure: What, Where, and How Many? NREL Perspective", National Governors Association Meeting. April 4, 2019

[27] McKinsey & Company, "Charging Ahead: Electric-Vehicle Infrastructure Demand". October 2018.

[28] US DOE, "National Plug-In Electric Vehicle Infrastructure Analysis". September 2017.

Table 8. Distribution of PHEV Charging Energy Demand Across Five Charging Categories

Charging Category	Share
RL1	66%
RL2	22%
WL1	4%
WL2	4%
PL2	4%

Additionally, charging categories for medium-duty (MDEVs) and HDEVs were included for Connecticut, reflecting the GC3's 2018 analysis which signified the importance of their electrification.[29,30] Vehicle stocks for HDEVs and MDEVs represent the total number of vehicles in each category based on the calculated total annual demand for HDEVs and MDEVs, where each category is allocated 50% of the Connecticut Electrification load attributed to non-LDEVs. Modeled daily total energy charging demand for the HDEV and MDEV fleet represents the product of daily demand multiplied by the respective vehicle stocks for each category. HDEVs and MDEVs were assumed to charge on level 3 chargers that deliver up to 50 kW per hour. [31]

Incremental energy demand from EV charging in the Electrification load cases is not pre-scheduled at the hourly level and is endogenously determined in the Aurora model. To capture the nuances of different charging categories, each category was assigned a charging window and a driving window. The charging window for each category reflects the most likely continuous period in which EVs would plug in at any of those locations. In real world applications, it is feasible that vehicles may choose to plug in to residential or public chargers throughout the entire day but aggregating charging behaviors was a reasonable simplifying assumption. Given the spread of charging across categories as shown in Table 7 and Table 8, there could have been some additional EV charging demand to the Base load EV demand in every hour of the day. Hours included in the charging window for each category are indicated with a "+" in Table 9.

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[29] While reasonable to assume there will be electrification of these larger vehicles in other New England states, only the electrification of LDEVs was modeled for other states.

[30] The Governor's Council on Climate Change, "Building a Low Carbon Future for Connecticut: Achieving a 45% Emissions Reduction by 2030". 2018. https://portal.ct.gov/media/DEEP/climatechange/publications/BuildingaLowCarbonFutureforCTGC3Recommendationspdf.pdf

[31] California Environmental Protection Agency - Air Resources Board, "Technology Assessment: Medium- and Heavy-Duty Battery Electric Trucks and Buses". October 2015.

Table 9. Charging Availability by EV Category

Hour Ending	RL1	RL2	WL1	WL2	PL2	PL3	HDEV
1	+	+	-	-	-	-	+
2	+	+	-	-	-	-	+
3	+	+	-	-	-	-	+
4	+	+	-	-	-	-	+
5	+	+	-	-	-	-	+
6	+	+	+	+	-	-	-
7	+	+	+	+	+	+	-
8	+	+	+	+	+	+	-
9	-	-	+	+	+	+	-
10	-	-	+	+	+	+	-
11	-	-	+	+	+	+	-
12	-	-	+	+	+	+	-
13	-	-	+	+	+	+	-
14	-	-	+	+	+	+	-
15	-	-	+	+	+	+	-
16	-	-	+	+	+	+	-
17	+	+	+	+	+	+	-
18	+	+	-	-	+	+	-
19	+	+	-	-	+	+	-
20	+	+	-	-	+	+	+
21	+	+	-	-	+	+	+
22	+	+	-	-	+	+	+
23	+	+	-	-	-	-	+
24	+	+	-	-	-	-	+

Daily charging demand for each category could spread throughout the available charging window hours and will vary with changes in renewable generation, seasonal loads, and market price signals.

6.5 Air Source Heat Pumps Demand Projections

Penetration schedules of ASHP demands were derived using the following method:

- The numbers of occupied housing units by space heating fuel type and state from the US Census Bureau American Community Survey (ACS) for 2013-2017 was selected as the basis for conversion to efficient ASHP electric heating. Growth in the housing stock through 2040 was not projected. Conversion penetrations by 2040 from existing space heating fuels were projected as shown in Table 10 for the Base and Electrification load cases. First, generic rates were specified for New England. Then, the conversion rates for Rhode Island were adjusted down in the Base Case and up in the Electrification Case to conform with the total ASHP installations by 2040 projections provided by Rhode Island for this Study.[32]

[32] Installations data provided by the RI Office of Energy Resources.

Table 10. Shares of Existing Space Heating Fuels Converted to ASHP by 2040

	Base Case		Electrification Case	
	Other States	**Rhode Island**	**Other States**	**Rhode Island**
Natural Gas	15%	13%	40%	60%
CNG, LPG	20%	17%	60%	81%
Electric Resistance	25%	21%	80%	90%
Oil	20%	17%	60%	81%
Wood	0%	0%	0%	0%
Other	0%	0%	0%	0%

These assumptions result in a total of nearly 1 million ASHP installations in New England by 2040 in the Base Case and slightly more than 3 million installations in the Electrification Case.

- For all states except Rhode Island, annual ASHP installations by state began with estimated 2019 installations from a report by the Vermont Energy Investment Corporation.[33] Then, S-shaped installation growth curves were calculated by state, starting with the 2019 estimated installation, in order to have the cumulative stocks of ASHP units reach the 2040 state targets for the Base and Electrification cases. Rhode Island provided its 2019 initial stock and annual 2020 to 2040 installations for both load cases.
- Energy use per installation data were estimated based on a 2019 NYSERDA Study that reported results for upstate and downstate (NYC/LI/LHV) New York regions.[34] The NYSERDA electric use data for single-family units were applied to New England. The NYSERDA study's data for small multi-family units was usage per installation without specifying the size of the buildings, so that data was not utilized. The downstate New York estimates for space heating and cooling were used as proxies for the southern New England states (CT, MA, RI). Upstate New York estimates for space heating and cooling were used as proxies for the northern New England states (ME, NH, VT). The simple average of the values for electricity use for centralized ASHP units in existing buildings and mini-split ASHP units for both existing buildings and new construction were calculated to estimate the heating energy use per ASHP unit for the two New England climate zones.
- For the Base Case, only the heating season (October-April) increase in electric use for ASHPs that replace non-electric heating fuels is attributed to the ASHP portion of electric energy load in the Base Case. As noted by ISO-NE, almost all ASHPs are installed within EE programs and their energy savings when substituting for resistance electric heating and conventional air conditioners are provided to ISO-NE by EE program administrators and

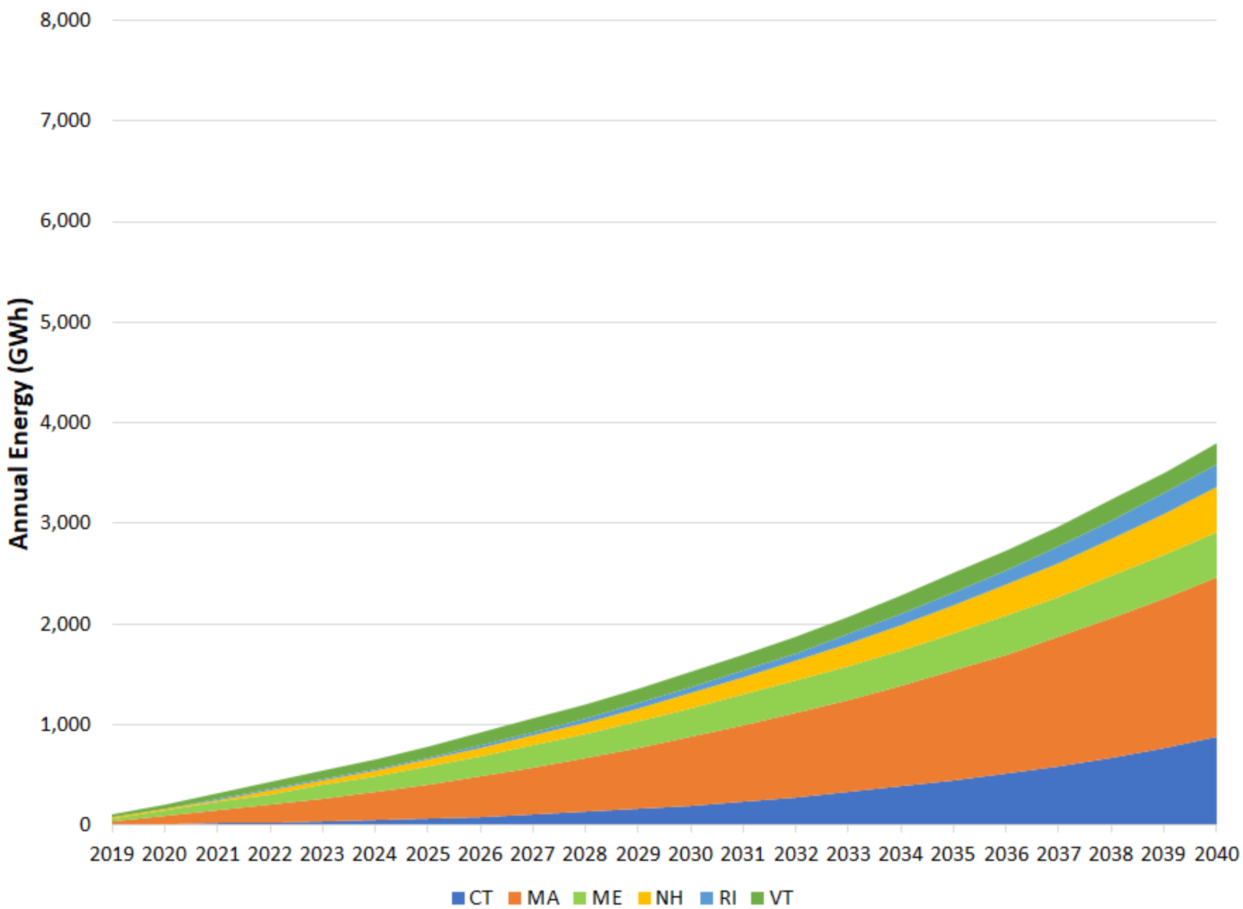
[33] VEIC, "Driving the Heat Pump Market: Lessons learned from the Northeast". February 20, 2018, Table 2.

[34] NYSERDA, *New Efficiency: New York: Analysis of Residential Heat Pump Potential and Economics, Final Report*. Report 18-44. January 2019, Table 6-2. https://www.nyserda.ny.gov/-/media/Files/Publications/PPSER/NYSERDA/18-44-HeatPump.pdf

included in the ISO's projection of EE savings.[35] Based on the NYSERDA study's values for ASHP cooling energy and counterfactual cooling energy values, ASHPs do not provide a substantial energy savings for cooling.

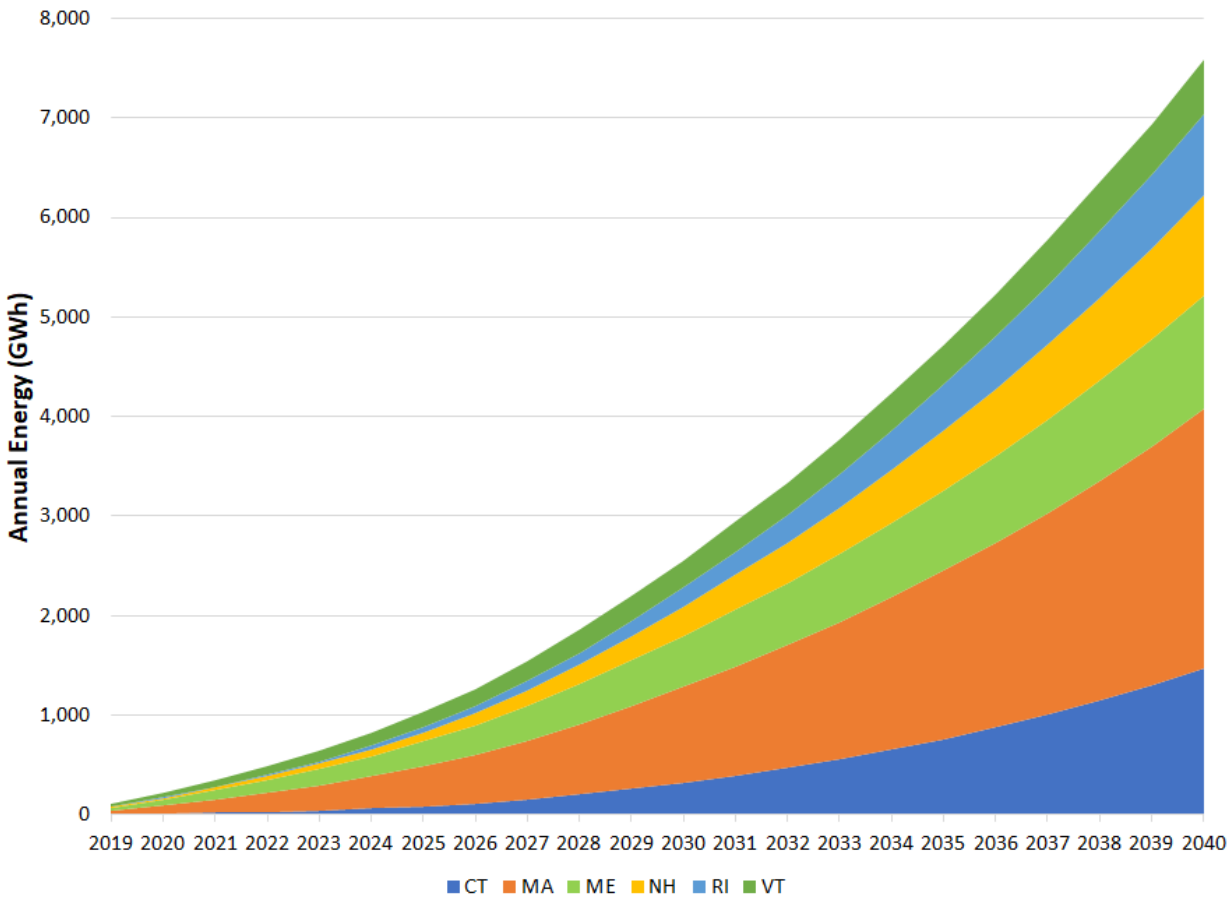
- For the Electrification Case, the annual *increase* in cumulative housing units over the Base Case that are converted to ASHPs from resistance heating is multiplied by the energy savings per ASHP unit and added to the extra heating energy use for units converted from non-electric heating. The reason for this incremental treatment of ASHP units converted from resistance heating is that the Electrification Case does not assume additional EE except for weatherization. This approach also allows the same ASHP hourly profile to be used for both load cases, for consistency.

Figure 10: ASHP Projections by State, Base Load Case



[35] Jon Black, ISO-NE, "Update on 2020 Heating Electrification Forecast", November 18, 2019 presentation to the ISO-NE Load Forecast Committee, slide 4.

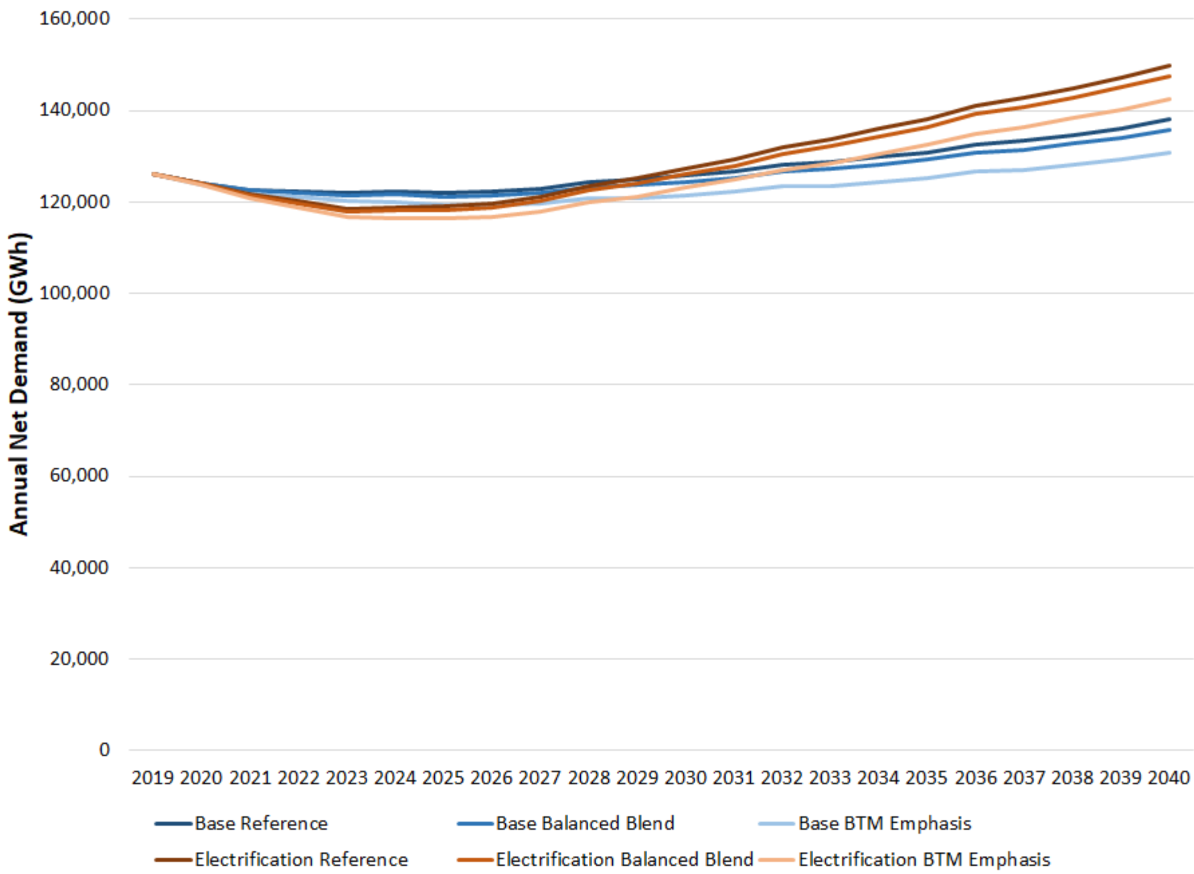
Figure 11: ASHP Projections by State, Electrification Load Case



6.6 Net Demand

Net metered demand is calculated as conventional gross demand minus EE savings minus BTM PV generation plus EV demand plus ASHP demand.

Figure 12: Net Demand Comparison



7 Coincident Hourly Load and Wind and Solar Energy Profiles

The annual hourly profile of net metered demand changes over time, and between the Base and Electrification load cases because each demand-side component has a different hourly profile. Representative weekly profiles by month were adjusted for weather (temperature, cloud cover) differences by state for the 2011 weather year.

Hourly wind profiles were created for all existing wind resources in ISO-NE with nameplate capacities greater than 5 MW and for all current BOEM offshore wind lease areas. To create these profiles, NREL's WIND Toolkit database was used.[36] Information from one to three WIND Toolkit location points was used to create each profile for the 2011 weather year. The number of points used depended on their proximity and position relative to the location being profiled. Adjustments were made to the studied years to match the days of the base weather year used for load, account for leap years, and shift from standard to prevailing time.

[36] See NREL, "Wind Integration National Dataset Toolkit" for more information. https://www.nrel.gov/grid/wind-toolkit.html

Hourly solar PV profiles were created for all existing solar resources in ISO-NE with nameplate capacities greater than 5 MW and selected smaller units chosen to increase geographic diversity. One or two generic profiles were created for each state, based on its geographic area. All solar output profiles were created using the PVWatts model in NREL's SAM application for the 2011 weather year.[37] All existing resources were modeled as fixed mount with 20° tilt, except for one resource that was verified to be tracking. Generic profiles were modeled in both fixed mount with 20° tilt and tracking with latitude degrees tilt. Adjustments were made to the profiles to match the days of the base weather year used for load, account for leap years and shift from standard to prevailing time.

All load hours for gross load net of PDR were projected by utilizing the historic load profile modified per the annual and monthly average and peak load projections.

8 Fuel Price Projections

Fuel prices, as delivered to generators, were projected for natural gas, oil products, and coal. Nuclear generators are price-takers and have virtually no dispatchability. Therefore, a nuclear fuel price projection is not required for Aurora. Instead, operational nuclear units were assumed to run fully loaded, limited only by planned outage schedules and forced outage rates.

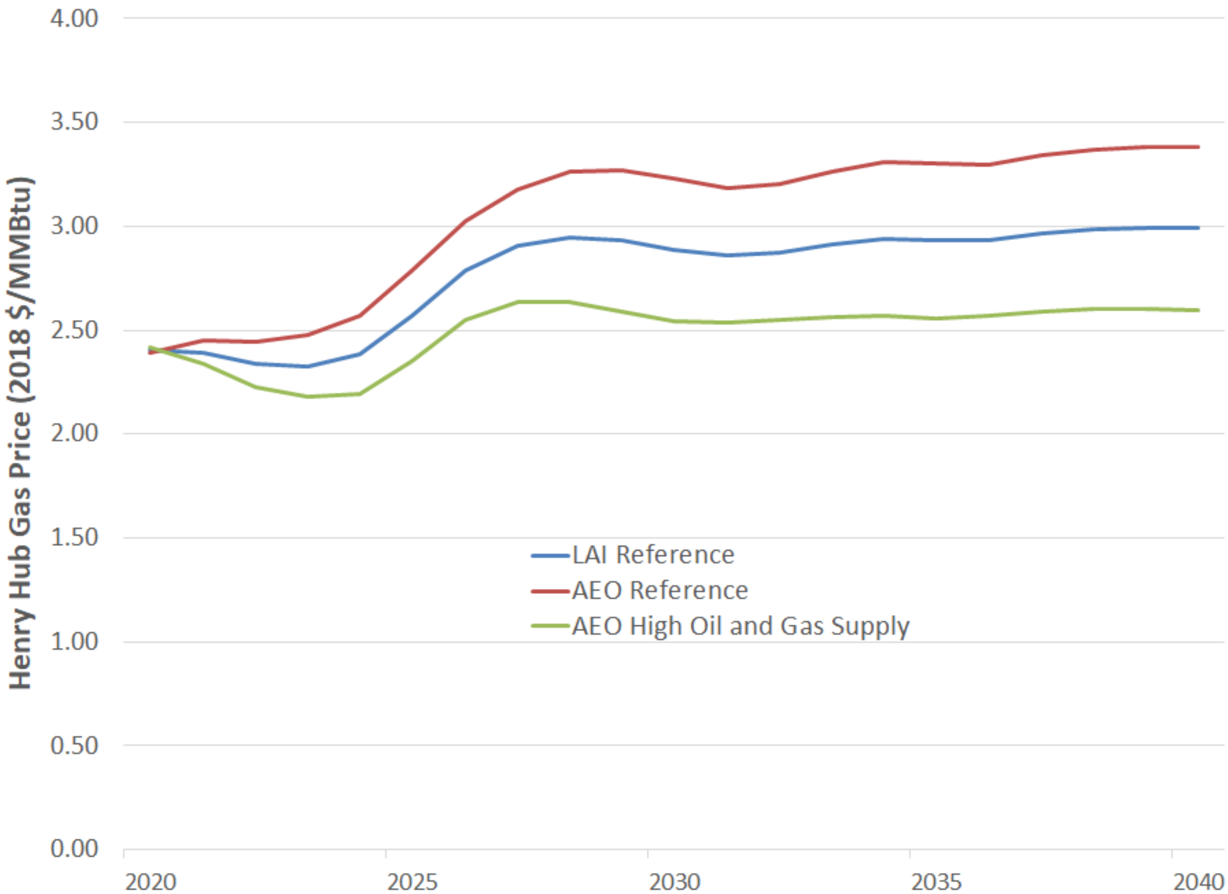
8.1 Natural Gas Prices Projections

Consistent with prior gas price projections undertaken for DEEP on multiple procurements and the Dominion matter as well, the projection of delivered natural gas prices started with a Henry Hub commodity price projection from EIA's 2020 Annual Energy Outlook (AEO). Historically, the AEO Reference Case has frequently overestimated the actual trajectory of natural gas prices. To account for this tendency, the AEO Reference Case and the AEO High Oil and Gas Supply Case were averaged together as illustrated in Figure 13.[38] Monthly shaping of natural gas prices into-the-pipe at the Henry Hub was applied to the annual prices over the Study Period based on the average monthly profile of historical Henry Hub prices observed over the last ten years. The Henry Hub gas price projection was held constant for all scenarios tested.

[37] See NREL, "System Advisor Model" for more information. https://sam.nrel.gov/

[38] For the 2020 AEO, EIA changed the name of the High Oil and Gas Resource and Technology Case to the High Oil and Gas Supply Case.

Figure 13: Annual Average Natural Gas Henry Hub Price Projections



The basis differentials between Henry Hub and New England interstate pipeline pricing points have shrinking importance over the Study Period as natural gas consumption by generators is reduced with more clean energy generation and as ASHPs displace gas utility send-out to "core" residential and commercial customers throughout New England. Technology substitution effects attributable to increased ASHP penetration lowers both pipeline utilization rates and local system usage, thereby lessening the frequency and magnitude of congestion events otherwise causing periodic spikes in the delivered cost of natural gas.

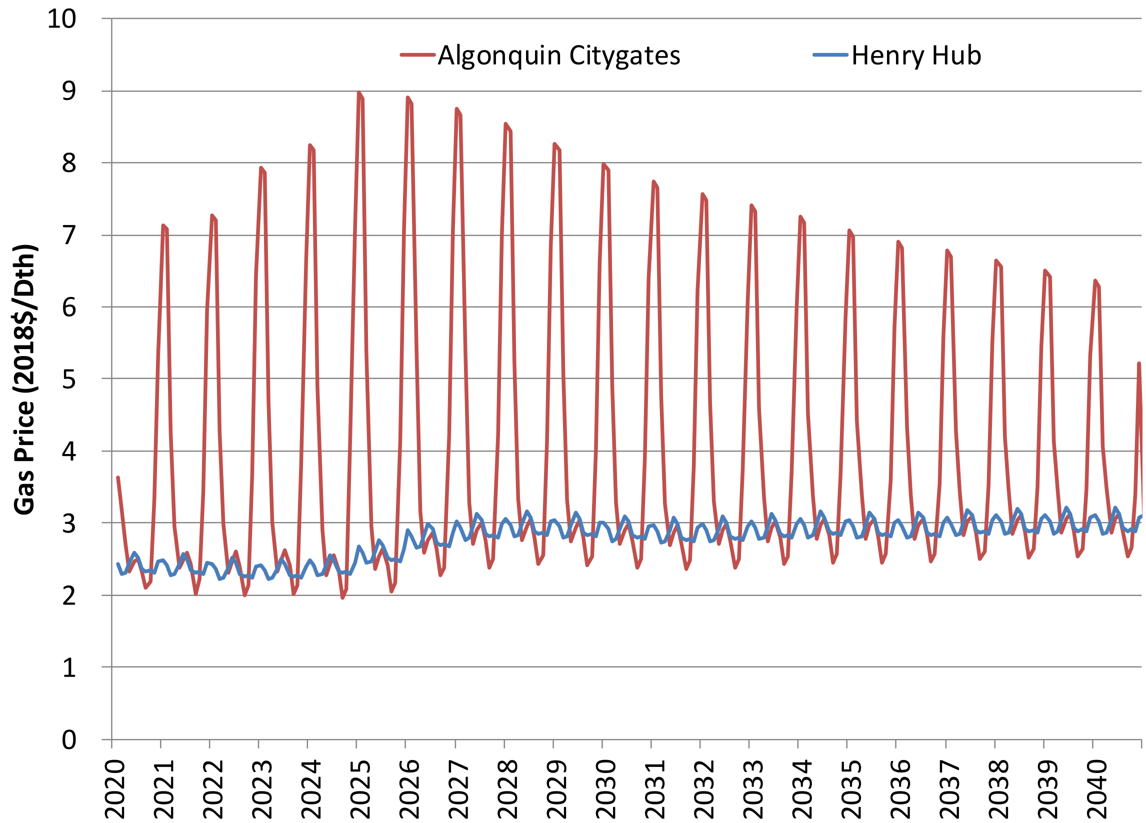
OTC Global Holdings natural gas forwards monthly prices minus Henry Hub monthly prices, i.e., OTC gas futures, were used as the starting point for New England regional basis. Basis differentials were projected for the following locational pricing points:

- Algonquin Citygates
- Iroquois Zone 2
- Tennessee Zone 6

OTC Global Holdings reports forwards for ten years. Beyond the period for which OTC data was available, basis was extrapolated for the remainder of the Study Period. For example, the Algonquin Citygates basis forward price for the peak winter months increases from 2020 through

2025, and then declines through 2029/early 2030. The basis projection to 2040 was extrapolated based on the year-over-year average percentage change for each month from 2024 through 2029. Figure 14 shows the resultant delivered Algonquin Citygates monthly prices relative to the Henry Hub monthly prices over the Study Period. No explicit price analysis was conducted to account for the loss of Distrigas upon expiration of the Mystic Cost of Service (Reliability Must Run) contract, or uncertainties surrounding the performance of Repsol Canaport and/or Excelerate to supplant lost output from Distrigas in 2024. The uncertain market responsiveness associated with LNG infrastructure was assumed to be baked into the OTC future prices.

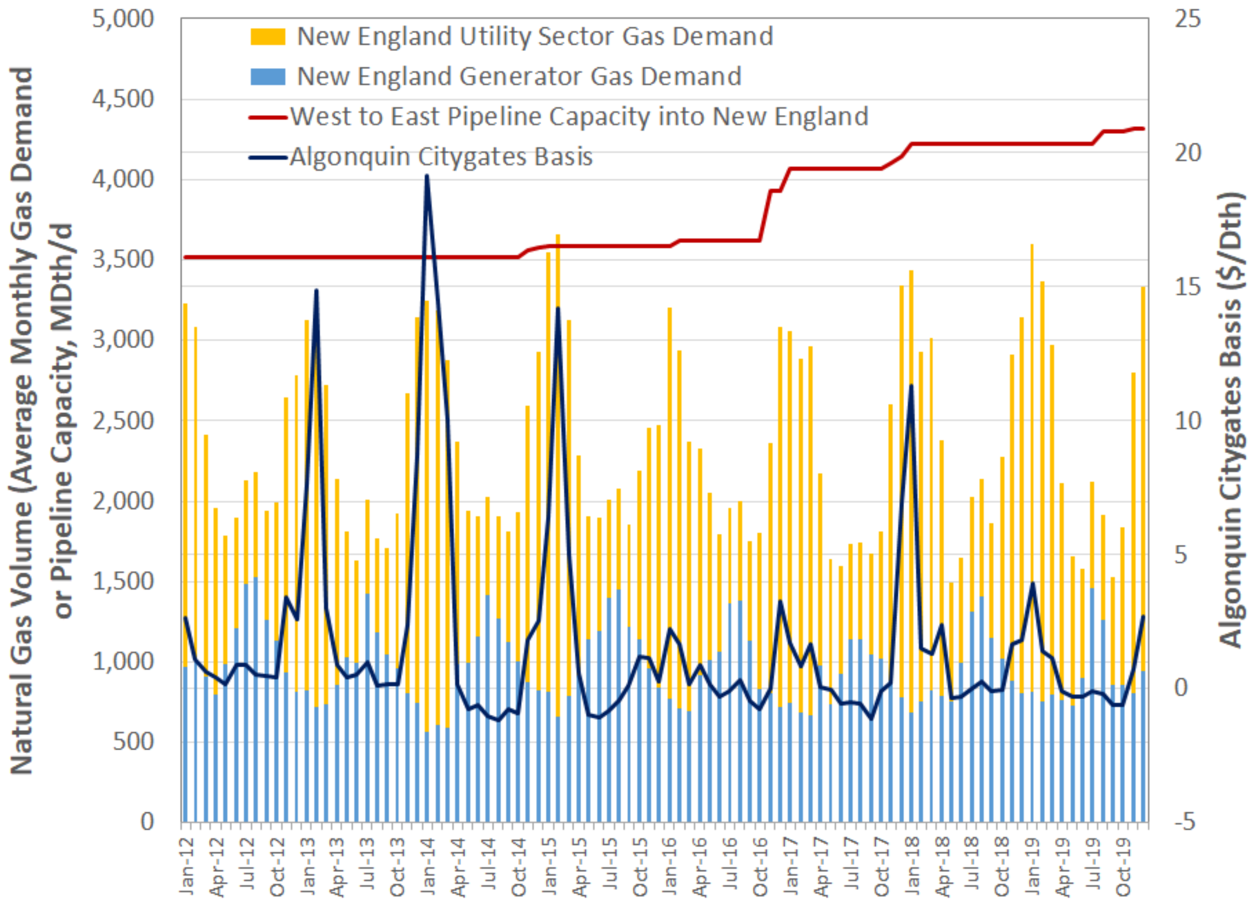
Figure 14: Monthly Average Natural Gas Price Projections for the Henry Hub and Algonquin Citygates[39]



The basis projections for specific scenarios were adjusted based on changes to gas demand for electric generation and the utility sector. The basis demand curve for the adjustments was estimated from statistical analysis of historical spot price and natural gas consumption data. Figure 15 illustrates the market data underlying this estimation, including average monthly natural gas demand, regional pipeline capacity, and basis.

[39] Algonquin Citygates projection is based on forward prices as of January 8, 2020.

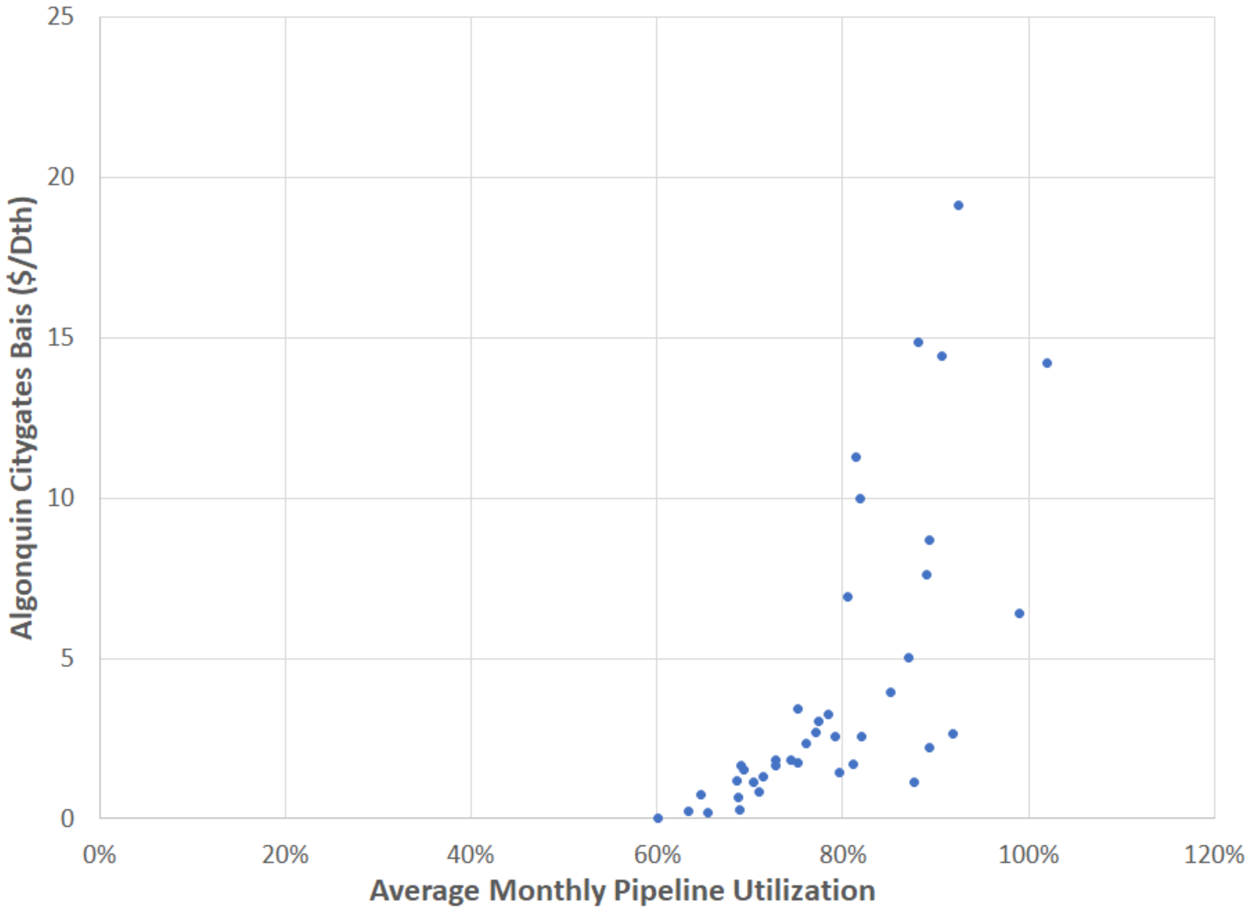
Figure 15: Historical New England Natural Gas Market Data



Basis is related to pipeline utilization, or total natural gas demand divided by pipeline capacity.[40] Figure 16 re-plots the sum of average monthly generator and utility sector gas demand divided by pipeline capacity, as shown in Figure 15, against average monthly Algonquin Citygates basis for the winter months. This relationship was used to update the scenario-specific gas price projections for the final production cost modeling runs, as described in section 13.2.

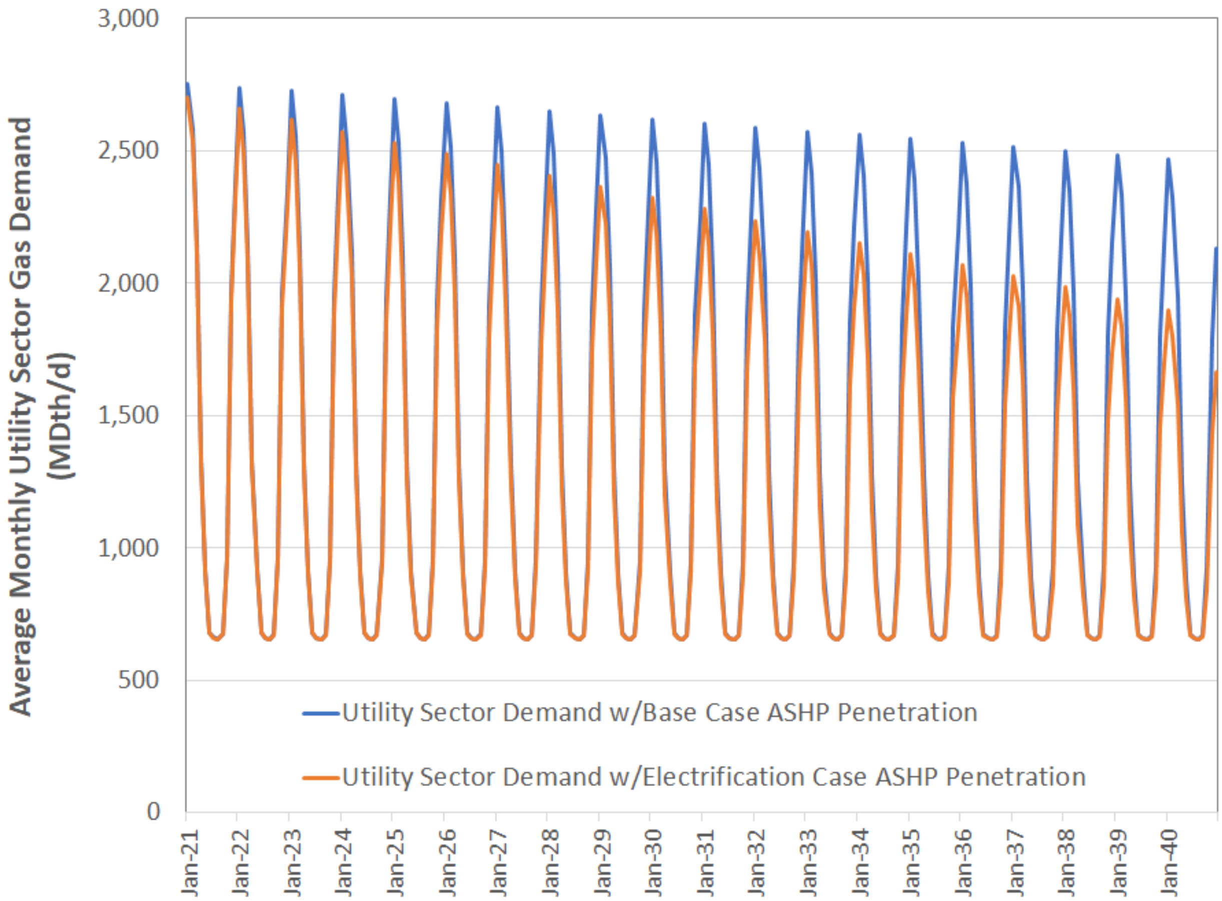
[40] This is a simplification of the complex basis drivers in the New England natural gas market. Other factors, such as LNG imports, are driven by both congestion and basis. For purposes of this basis adjustment estimation, the focus was placed on the forecast variables which could be derived from policy assumptions or extracted from preliminary Aurora runs. Consideration of Repsol Canaport's and/or Excelerate's ability to leverage existing infrastructure to realize economic rents during the peak heating season is not part of this analysis.

Figure 16: Basis vs. Pipeline Utilization (November through March)



For the case-specific adjustments, generator gas demand was extracted from Aurora, utility sector gas demand was adjusted from 2019 levels based on the air source heat pump demand projections described in section 6.5 (shown in Figure 17), and pipeline capacity was held constant from the end of 2019.

Figure 17: Utility Sector Gas Demand Adjustments



8.2 Other Fossil Fuel Price Projections

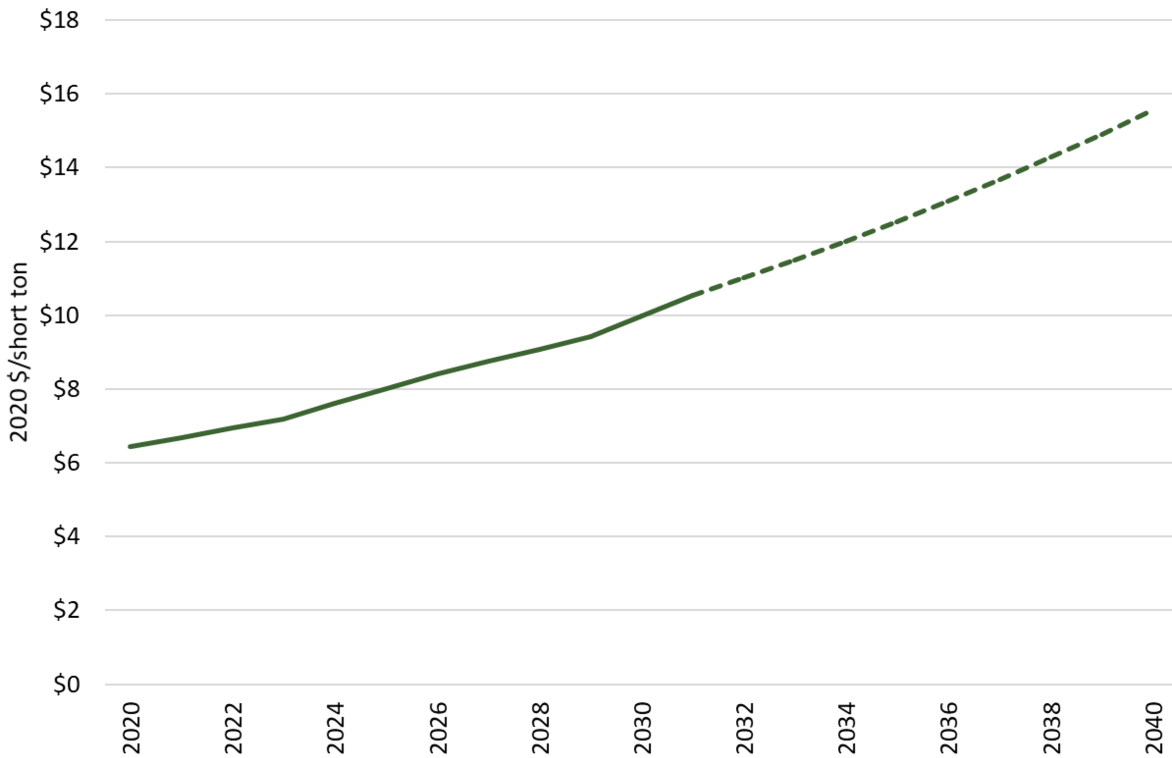
Delivered oil products prices were set based on the 2020 AEO as the average of the AEO Reference Case and the AEO High Oil and Gas Supply Case, consistent with the Henry Hub gas price projection.

Coal prices were set using the 2020 AEO prices for delivered coal to electric generators as a commodity price. These prices were then adjusted on a unit and state level to reflect local price adders based on basin sourcing and transportation costs. These adders were developed by Energy Exemplar and are primarily based on a review of EIA-923 fuel receipts data.

9 Carbon Allowance Price Projection

The projection of CO_2 allowance prices in Figure 18 is based on the RGGI Model Rule Policy Scenario forecast prices that were prepared on behalf of the 2017 RGGI Program Review conducted by the RGGI Stakeholder Group. RGGI prices were extrapolated to continue the trend in the current program review. Prices beyond 2031 were escalated by applying the growth rate observed in the program review prices.

Figure 18: CO_2 Allowance Price Projection



10 Scenario Specific Resource Assumptions

In all resource cases aside from the Millstone Extension case, Millstone units 2 and 3 retire upon expiration of the current PPA at the end of September 2029. Millstone is partially replaced by a 1000 MW HVDC controllable tie line, which exports into New England at an 80% capacity factor (approximately 7 TWh of net exports annually). No other generic clean energy generation resources are scheduled into the model for the Reference, Balanced Blend, and Transmission cases. For the BTM Emphasis resource case, additional BTM solar is promoted as described in section 6.3.

In the Transmission cases all transmission constraints are relaxed, which results in delayed or reduced clean energy build. Candidate resources are restricted to those added in the Balanced Blend scenario with the same load case applied. This restriction ensures that the resource buildout and prevailing transmission flows behave similarly to the Balanced Blend scenarios and are therefore comparable.

In the Millstone Extension case, both Millstone units receive a long-term contract that ensures their operation through 2040. HVDC tie lines to Canada remain a candidate resource but none beyond NECEC are firmly scheduled additions.

11 Capacity Expansion

Capacity expansion planning for each scenario used Aurora's Long-Term Capacity Expansion economic optimization modeling functionality to determine an equilibrium path of annual resource additions and retirements beyond scheduled additions and retirements that meet the modeled planning and operational constraints.

Under this functionality, Aurora calculates the present value of all existing resources and determines which generators are candidates for retirement based on value over the Study Period. The model iterates to an equilibrium solution given potential candidate new resource options and retirements. In each iteration an updated set of candidate new resource options and retirements is placed into the system and the model performs its chronological commitment and dispatch logic for those resources. The model tracks the economic performance of all new resource options and resources available for retirement based on market prices developed in the iteration. At the end of each iteration the long-term capacity expansion logic decides how to adjust the current set of new builds and retirements until it determines that the model has converged on an optimal solution.

11.1 Long-Term Constraints

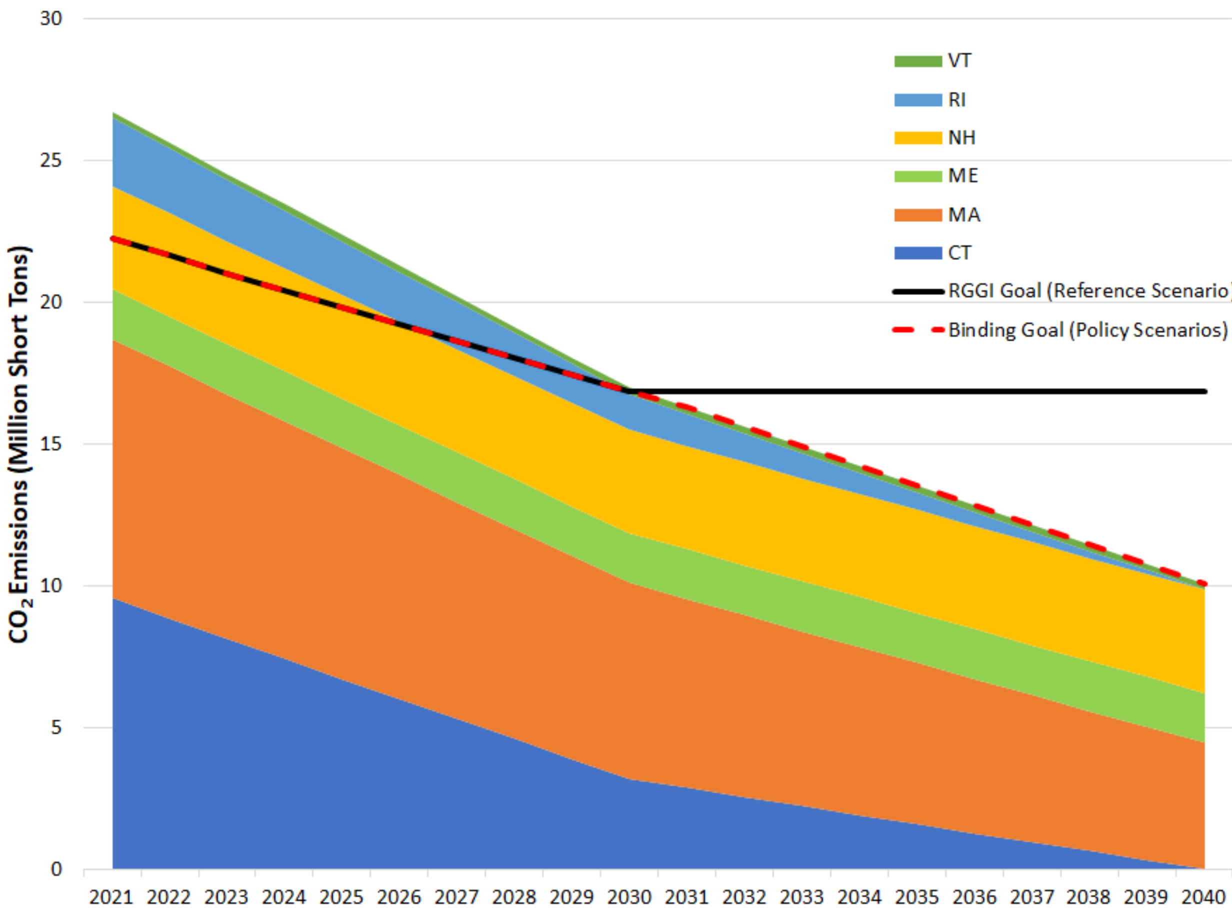
Aurora allows for implementation of various capacity expansion constraints to comport with environmental and reliability objectives. The capacity expansion schedule respected two input constraints, (1) a clean energy constraint meant to respect regional GHG emissions targets and (2) a Planning Reserve Margin constraint meant to enforce resource adequacy similarly to ISO-NE's net Installed Capacity Requirement (ICR) calculation. The capacity expansion schedule output affected operating reserve constraints which were applied to downstream production cost modeling.

11.1.1 GHG Emission Constraints

GHG emissions targets were the driver used to estimate clean energy build for ISO-NE. For the Reference Portfolio Case, the initial modeling approach was to enforce mandated electric sector specific GHG targets for the states that have them. As only Massachusetts had a mandated goal when the assumptions were developed, the RGGI cap was the binding emissions goal in all years for New England.[41] For the clean energy portfolio cases, aspirational GHG targets were enforced for the states that have them. To prevent leakage, states with no aspirational electric sector specific emissions target at the time of modeling (ME, NH) were assumed to hold emissions constant from 2016 values, the last year consistently available in state emissions inventories. The aggregated GHG emissions targets were translated into MWh of clean energy for inclusion in Aurora's capacity expansion model.

[41] The MA 310 CMR 7.74 emissions limits were included as an emissions constraint in production cost modeling.

Figure 19: Regional CO_2 Emissions Goals



Iterative adjustments to the clean energy constraints were made to improve adherence to emissions goals, as marginal emissions rates change depending on the composition of load and postulated clean energy resource mix.

11.1.2 Long-term Planning (Resource Adequacy) Requirements

Planning reserve capacity requirements were set per ISO-NE's net ICR calculation for FCA14. The net ICR calculation is projected forward based on the peak load calculated from the annual demand projections and hourly coincidence assumptions documented above. The Study utilized Aurora's dynamic peak capacity credit calculation method, which evaluated peak load contribution for VERs each year because the peak net load hour is expected to change over time, especially as solar PV capacity expands. Capacity expansion schedules for the Base Reference, Base Balanced Blend, Electrification Reference, and Electrification Balanced Blend scenarios were evaluated in MARS with the assistance of ISO-NE. Based on the MARS modeling results, planning reserve margins in the Electrification Load scenarios were escalated to better comply with ISO-NE's reliability requirements. These adjustments are further described in Appendix 2, MARS Modeling.

11.2 Scheduled Renewable and Clean Energy Resource Additions

The Reference Case included all renewable and clean energy projects, including OSW, that have approved contracts and/or which have been selected for long-term contract under a state-mandated procurement:

- The Vineyard Wind 800 MW OSW project has an approved contract and was proposed to have a phased in-service date of January 2022 for the first 400 MW and June 2022 for the remainder of total project nameplate. Vineyard Wind announced on August 12, 2019 that the project schedule will be delayed while requesting an extension of the Investment Tax Credit deadline with the IRS due to a delay in obtaining the necessary BOEM approval. As a result, the in-service dates will be delayed by one year. Vineyard Wind will deliver into SEMA.
- Deepwater's 700 MW Revolution Wind project was selected by NGrid Rhode Island (400 MW), the CT Clean Energy RFP (200 MW), and the CT Zero Carbon RFP (104 MW). Revolution Wind will deliver into the Rhode Island RSP subarea and is expected to be placed in service in 2023.
- The 1,200 MW New England Clean Energy Connect project, selected by the Massachusetts EDCs under the 83D procurement has been approved by the MA DPU. The project was given a 2023 in-service date, with scheduled annual energy delivery profile similar to that of HQ imports on the Phase II HVDC tie.
- For Phase II of the 83C procurement Massachusetts selected Mayflower Wind, an 804 MW project that will be completed in two phases coming into service in September and December 2025. The delivery zone is assumed to be SEMA.[42]
- Section 1 of Connecticut Public Act 19-71 directed CT DEEP to solicit offers for up to 2,000 MW of OSW. In December 2019, DEEP selected Vineyard Wind's 804 MW Park City Wind project. This project will begin delivery in 2025 and was assumed to deliver into SEMA.
- Table 11 provides an overview of the solar, land-based wind, and fuel cell resource additions that have been selected in recent Connecticut procurements. All the resources included in the table are under contract to be built by 2024 or earlier.

Table 11. Connecticut Resources Under Contract[43]

Procurement Event	Capacity (MW)
Best in Class Procurement	46
P.A. 15-107 Procurement	361
Clean Energy Procurement	356
Zero Carbon Procurement	164

[42] The proposed delivery point is confidential.

[43] The values in the table do not include offshore wind or nuclear projects awarded contracts through Connecticut state-sponsored procurements.

11.3 Scheduled Resource Retirements

ISO-NE retirement bids through FCA14 were reflected in the resource mix. Notable scheduled retirements are shown in Table 12.

Mystic units 8 and 9 were assumed to run through the end of the period covered by the RMR equivalent contract, which covers FCA 13 and FCA 14. Both Mystic units were assumed to retire at the end of the Capacity Commitment Period corresponding to FCA 14 or May 31, 2024.

Other than in the Millstone PPA Extension portfolio case, Millstone 2 and 3 were assumed to retire at expiration of the existing PPA on September 30, 2029.

Table 12. Notable Scheduled Retirements in ISO-NE

Resource Name	Capacity	Year of Retirement
Bridgeport Station 3	385	2021
South Meadow	189	2023
William F Wyman 1/2	103	2023
Mystic 7 & Jet	573	2023
Mystic 8 & 9	1,420	2024

11.4 Candidate Resource Additions

Candidates for capacity addition were offshore wind, land-based wind, utility-scale solar, battery storage, and Canadian clean energy over new HVDC ties. Each technology has unique operating parameters, costs, and siting constraints. The average capacity factors for each technology are listed below.

Aggregated Capacity Factors	
Technology	**Capacity Factor**
Biomass	93.1%
Fuel Cell	87.1%
Hydro	48.1%
Landfill Gas	84.1%
Onshore Wind	
CT	37.0%
MA	30.9%
ME	29.2%
NH	27.2%
RI	22.3%
VT	28.7%
Offshore Wind	40.8%
Solar Fixed Tilt	20.6%
Solar Tracking	23.8%

The Study considered multiple sources for project-specific capital and fixed O&M costs (NREL *2019 Annual Technology Baseline* data, EIA 2019 *Annual Energy Outlook* assumptions,[44] data from the 2022-2023 Forward Capacity Auction, etc.). After review of the various options, the chosen source for the base cost data used for calculating the capital and fixed costs was the NREL *2019 Annual Technology Baseline* (ATB) database. Lease area specific OSW spur line costs were calculated, based on NREL 2019 ATB cost data, adjusted by their distance to injection points.[45]

Capital structure and other financial assumptions from the NREL 2019 ATB database were used to calculate a real capital carrying charge rate, to convert the capital costs of each project into an annual real capital carrying charge. The annual capital carrying charge plus the annual real Fixed O&M costs were used in Aurora as an annual real fixed charge.

11.4.1 Offshore Wind

Offshore wind siting was determined by consulting the DOE's 2018 Offshore Wind Technologies Market Report,[46] which estimates OSW capacity potential by lease area and the capacity of contracted projects under development (Table 13). Some adjustments were made to the remaining OSW capacity potential per recent state-sponsored project selections. Net of current projects and some assumed "leakage" to further procurement initiatives in New York approximately 6,200 MW of remaining OSW potential remained in existing MA/RI lease areas.

Table 13: Offshore Wind Remaining Lease Area Potential for Candidate Resources

Lease Area	Potential (MW)
OCS-A 0500	2,277
OCS-A 0520	1,564
OCS-A 0521	743
OCS-A 0522	1,607

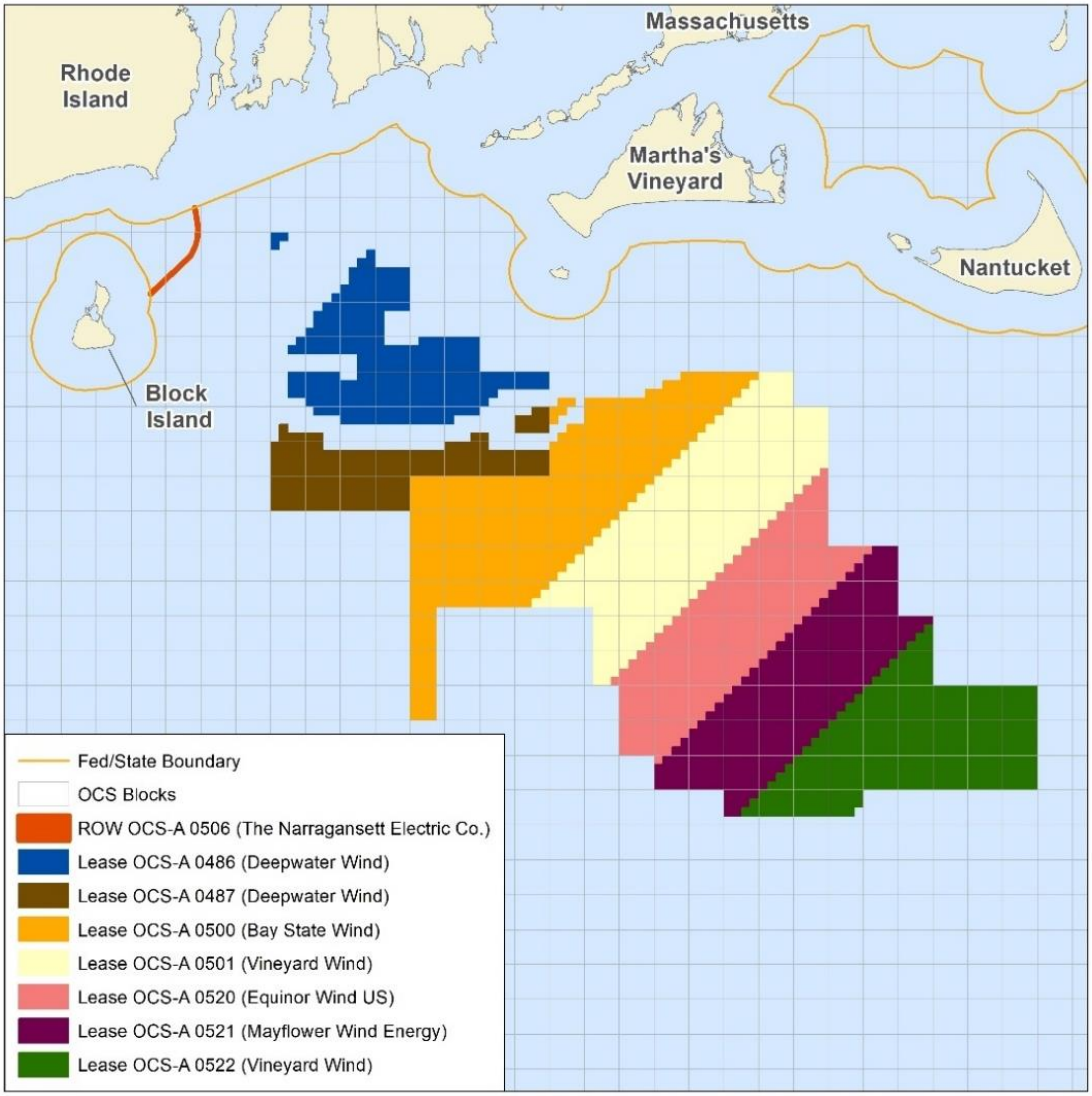
Lease area potential was divided into (approximately) 800-1,200 MW projects, consistent with the size of recently procured projects. Aurora was set to only allow one project to be built in a given lease area per year, and projects were added in roughly 400 MW annual phases. The first year that Aurora could build candidate offshore wind resources was 2026. Offshore wind projects in existing lease areas were assumed to use fixed foundations.

[44] U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2019*. January 2019. https://www.eia.gov/outlooks/aeo/assumptions/

[45] Based on OSW wind queue injection points identified in the ISO-NE interconnection database.

[46] DOE, Office of Energy Efficiency and Renewable Energy, *2018 Offshore Wind Technologies Market Report*. August 2019. https://www.energy.gov/eere/wind/downloads/2018-offshore-wind-market-report

Figure 20: Massachusetts and Rhode Island Offshore Lease Areas[47]



The Study also considered offshore wind potential outside of existing lease areas. More wind potential exists outside of current lease areas. However, new BOEM "call" areas would have to be sited off the coast of Maine and New Hampshire or still further offshore from Massachusetts and Rhode Island. Future call areas may be developed later in the Study Period after all existing lease areas have been developed and will require floating foundation technology. Precise locations for future call areas off the coasts of Massachusetts / Rhode Island and Maine are not available from BOEM.[48] Therefore, nautical maps, maritime traffic patterns and other factors were considered to determine possible favorable locations for expansion. For Massachusetts / Rhode Island, an area to the east and northeast of the current lease areas and south of Nantucket was chosen. For Maine, an area off the coast of Portland was chosen. To reflect the uncertainty

[47] BOEM Lease OCS-A 0487 is being developed for New York as Sunrise Wind.

[48] BOEM has established a Gulf of Maine intergovernmental task force, but it has only met once so far.

regarding these profile locations, WIND Toolkit data was sampled from a broader geographic range of sites. The Study assumes an additional 4,800 MW of development potential farther offshore than the existing Massachusetts / Rhode Island lease areas, and another 5,000 MW of development potential off the coast of Maine. Both new areas will be in deeper water and will require floating platform technology.

NREL's 2019 ATB database reports project-specific capital, FOM, and other costs, in 2017 dollars, for various techno-resource groups (TRGs). For example, the ATB reports 5 categories of offshore fixed wind, and 10 categories of offshore floating wind. Fixed TRG-3 for offshore fixed wind and Floating TRG-6 for offshore floating wind were the selected TRGs for cost projections.

Offshore wind points of interconnection were informed by the Economic Studies that ISO-NE have recently conducted on behalf of NESCOE and Anbaric, which examined varying levels of offshore wind development. Offshore wind interconnections were spread throughout the SEMA, RI, CT, and Boston subareas, with most interconnections made in SEMA/RI.

11.4.2 Land-based Wind

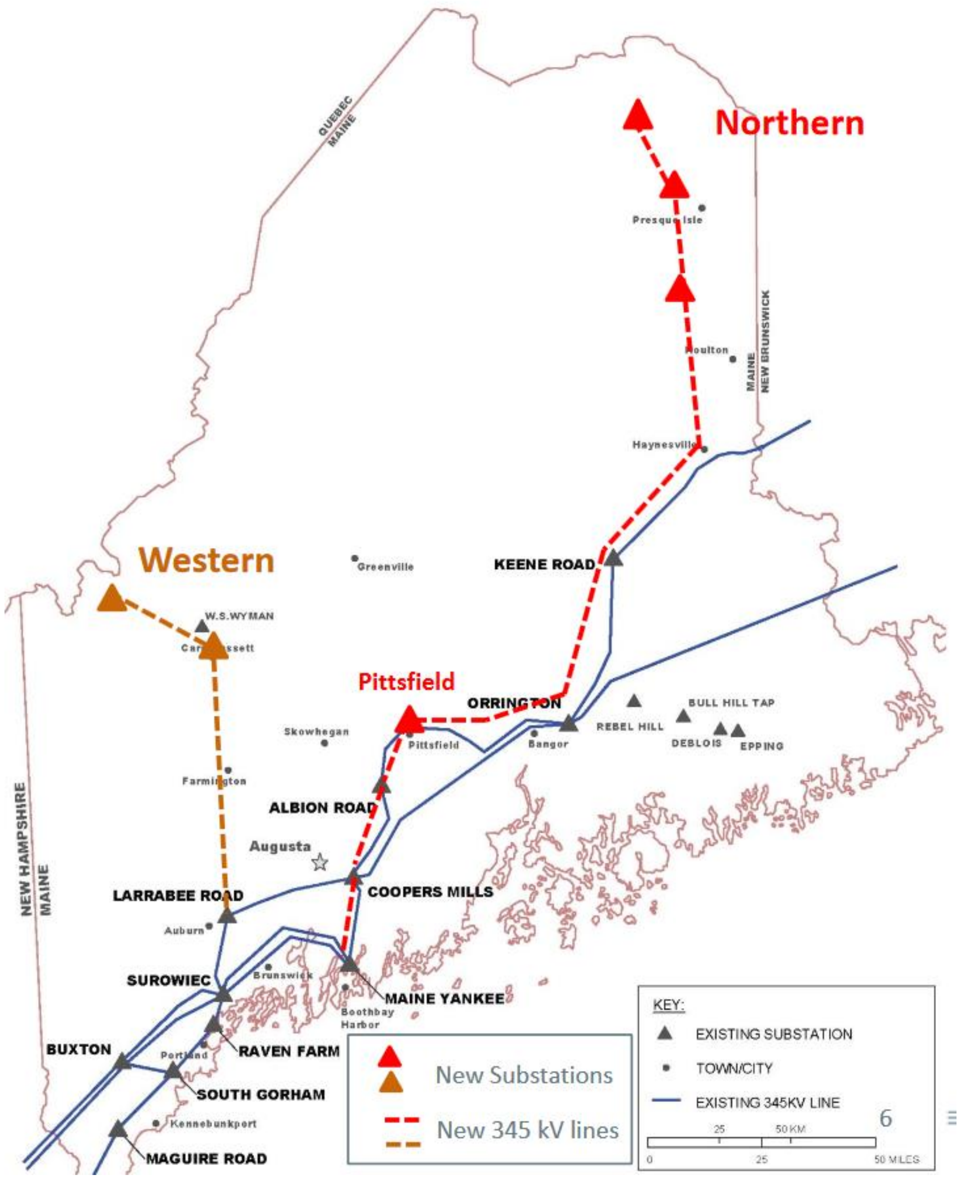
Significant land-based wind (LBW) potential exists in Northern New England, but siting and transmission constraints are well documented. ISO-NE's 2017 Economic Study materials reviewed the congestion effects of nameplate wind injections into Maine. The ISO-NE Economic Study's Reference Renewables Plus scenario found that a 3,652 MW nameplate wind injection into Maine would require 1,839 MW of congestion relief capacity, which implies that about 1,800 MW of nameplate could be added before congestion relief is needed. However, New England Clean Energy Connect will utilize about two-thirds of this capability. The high-level order-of-magnitude costs in the Economic Study suggest that a congestion relief solution may cost $3.73 to $5.60 billion, or roughly $2,000 to $3,000 per kW of installed wind nameplate.[49] Given the expected cost declines in OSW technology and high project-on-project risk of a coupled LBW and transmission solution, the development potential of LBW was quite limited relative to OSW.

In addition to standard capex expectations, many of the wind sites in ISO-NE region are located very far from the bulk power system and will require significant investment for grid integration. To facilitate economies of scale, ISO-NE has introduced a cluster interconnection process that allows for groups of generators to request interconnection as a "cluster". Two interconnection clusters, Western and Northern, have been defined in Maine. These clusters are not entirely made up of wind resources, but they represent the lion's share of generation. The 2016/2017 Maine Resource Integration Study estimated the costs for associated upgrades; on a unit basis the Western upgrades would cost approximately $625/kW and the Northern upgrades would cost approximately $1,200/kW. Since the initial creation of the Northern Cluster several generators

[49] Haizhen Wang and Marianne Perben, ISO-NE, "2017 Economic Study". Presented February 14, 2018 to the Planning Advisory Committee.
https://www.iso-ne.com/static-assets/documents/2018/02/a3_2017_economic_study.pdf

have withdrawn. The cluster is now 517.5 MW and per-unit costs have increased to $1,500/kW.[50] Based on these studies and their representation of siting and transmission constraints, generic wind expansions were created of 700 MW and 500 MW, respectively, with capex premiums added to represent integration costs. The earliest the projects could be selected for build by Aurora were 2024 and 2026, respectively.

Figure 21: Maine Wind Resource Integration Clusters[51]



[50] Al McBride, ISO-NE, "Second Maine Resource Integration Study: Results". Presented November 20, 2019 to the Planning Advisory Committee. https://www.iso-ne.com/static-assets/documents/2019/11/a3_second_maine_resource_integration_study_final_results.pdf

[51] Source: Maine Resource Integration Study Presentation. https://www.iso-ne.com/static-assets/documents/2017/07/a3_maine_resource_integration_study_scenarios_and_cost_estimated.pdf

11.4.3 Utility-scale Solar PV and Distributed Solar PV

For the Reference Case, development potential was limited to what is currently in the ISO-NE interconnection queue. Contracted additions were netted out of the queued PV potential. Although many of the resource names are masked in the queue, most of the contracted resources are expected to have a queue position, and therefore scheduled additions were netted out to avoid double-counting. Inclusive of existing grid solar facilities, there is approximately 4,200 MW of development potential in the Reference Case.

For the Balanced Blend Case, a diffusion curve was used to calculate an implied upper-bound per two known points: approximately 1,300 MW of nameplate capacity in 2019 and 6,000 MW of nameplate capacity in 2030, as found in the ISO-NE's 2017 Economic Study renewable sensitivities. This curve yields a limit of 8,700 MW development by 2040, as shown by Table 14. State siting restrictions were pro-rated based on their shares of overall queued solar capacity.

Table 14: UPV Resource Potential

State	Reference Case Potential (MW)	Policy Cases Potential (MW)
CT	300	700
RI	400	650
MA	2,000	3,550
ME	950	2,450
NH	400	1,000
VT	150	350
Total	**4,200**	**8,700**

Utility-Scale Solar PV (UPV), Solar Distributed Commercial PV, and Solar Distributed Residential PV resource costs were estimated. Operating parameters were taken from NREL 2019 ATB data, using NREL's Mid Technology Cost Scenario.[52] Regional cost scaling by state was applied per EIA *Capital Cost Estimates for Utility Scale Electricity Generating Plants*[53] which included state cost estimates for PV fixed facilities.

Only the costs for the UPV category were used in the automated capacity expansion modeling. The distributed commercial and residential PV costs were used in the financial analysis for the pre-scheduled BTM distributed PV (DPV) capacity.

BTM solar PV, which is also included in the 2019 CELT report, is deducted after load net of EE is calculated to reflect the changes to hourly shape of net load that solar PV creates as BTM PV capacity grows over time, and at different rates in the Solar PV Emphasis portfolios relative to the

[52] Mid Technology Cost Scenario: based on the median of literature projections of future CAPEX; O&M technology pathway analysis. https://atb.nrel.gov/electricity/2019/index.html?t=su

[53] U.S. Energy Information Administration, "Capital Cost Estimates for Utility Scale Electricity Generating Plants", November 2016. https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf

other resource portfolios. The same methodology as used for UPV was employed to calculate resource costs for Distributed Commercial PV and Distributed Residential PV, using the corresponding data from NREL (2019 ATB database). The costs were then calculated on an annual basis by vintage (annual incremental MW of newly added BTM MW), and type (Distributed Residential and Distributed Commercial).

BTM PV needed to be disaggregated into appropriate portions of Distributed Commercial PV and Distributed Residential PV for cost-calculations. This was done by leveraging program-level information, provided by CT DEEP as part of ISO-NE's 2019 PV Forecast process.[54] The type of BTM by program was classified and used to calculate an annual % breakdown by type. The data source only provided the breakdown out to 2026 - a fixed ratio was set from 2026 to 2040. This ratio was used to apportion the annual Capex and Fixed O&M costs by type.

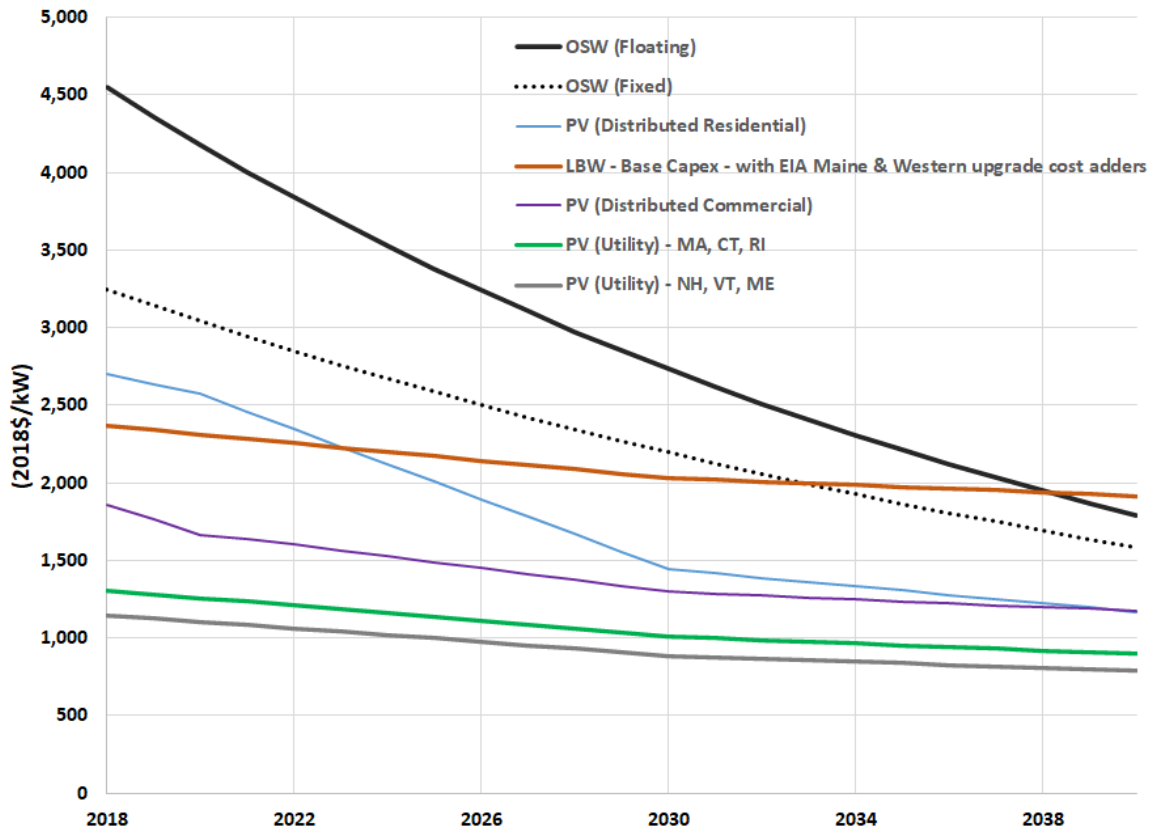
11.4.4 Capital Cost Trends by Renewable Generation Technology and Vintage

Figure 22 charts the capital costs trends for offshore wind, land-based wind, and utility-scale PV by vintage (in $2018/kW). Each point on the curve represents the capital costs for a plant built in that specific year. UPV has two curves for separate sets of states, differentiated based on their solar irradiance (NH, VT, and ME in one set; and MA, CT, and RI in the other).[55]

[54] Connecticut Department of Energy and Environmental Protection, "CT Policy Update". December 10, 2018. https://www.iso-ne.com/static-assets/documents/2018/12/2_ct_2018_12.10.2018.pdf

[55] The solar irradiance map used to differentiate the states is on the NREL website. https://atb.nrel.gov/electricity/2019/index.html?t=su

Figure 22: OSW, LBW, and PV Capital Costs by Vintage



11.4.5 Battery Storage

Lithium-ion battery storage resource options for 2-hour, 4-hour, and 8-hour maximum generation durations were considered as candidate resources. Operating parameters were taken from NREL 2019 ATB data and its main underlying source, the *2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark*.[56] That study estimated costs for 4-hour, 2-hour, 1-hour, and 30-minute storage systems with 60 MW of discharge capability and assumed cycle efficiency of 85%. Costs were scaled from the itemized breakdown in that study's Table 3 to estimate the cost for an 8-hour system, which is largely driven by the battery. Costs from the Benchmark study were scaled per the ATB Mid Case, which was further described in "Cost Projections for Utility-Scale Battery Storage".[57] The ATB Mid Case specifies costs reductions for a 4-hour storage system. Since NREL applied cost reductions to the power and energy components of the storage system equally, the 2-hour and 8-hour systems were scaled consistent with cost reductions used in ATB. Fixed O&M costs were set at 2.5% of the $/kW capacity cost for all storage durations. Then

[56] Fu, Ran, Timothy Remo, and Robert Margolis. *2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark*. Golden, CO: National Renewable Energy Laboratory. November 2018. NREL/TP-6A20-71714. https://www.nrel.gov/docs/fy19osti/71714.pdf

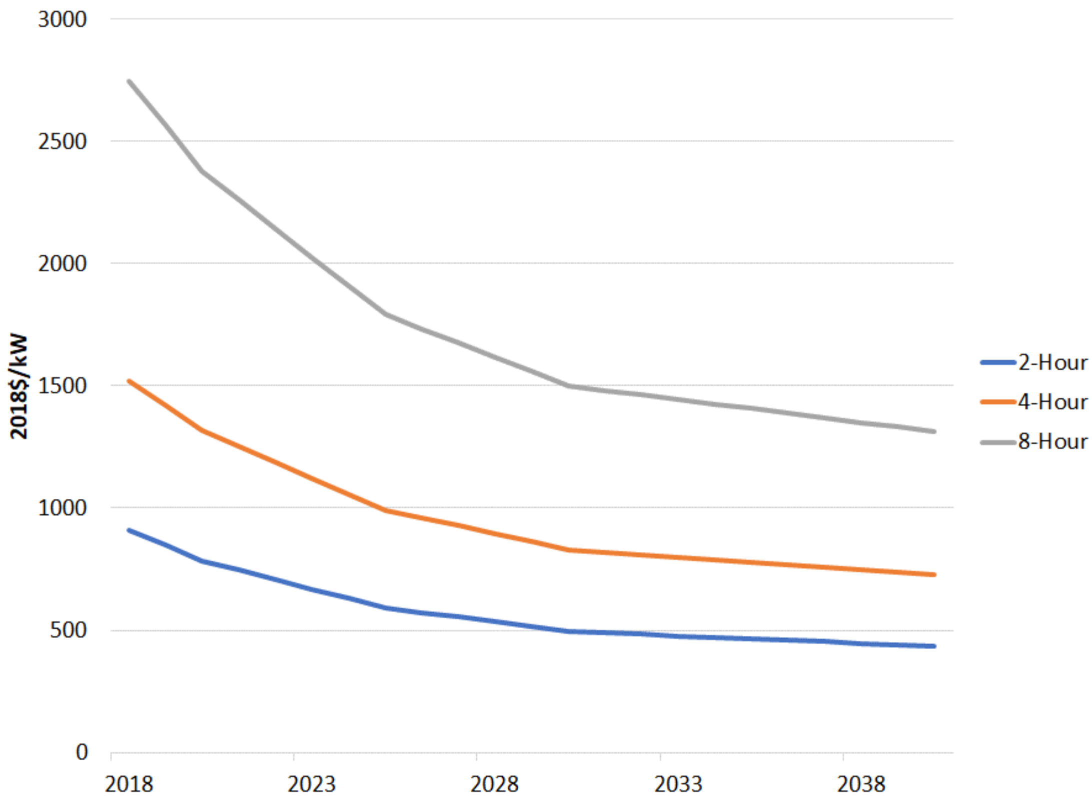
[57] Cole, Wesley, and A. Will Frazier. *Cost Projections for Utility-Scale Battery Storage*. Golden, CO: National Renewable Energy Laboratory. June 2019. NREL/TP-6A20-73222. https://www.nrel.gov/docs/fy19osti/73222.pdf

regional cost scaling by state was applied per EIA's 2016 "Capital Cost Estimates for Utility Scale Electricity Generating Plants" study, which included regional cost estimates for BESS technology.[58]

Table 15: Location-Based Storage Cost Adjustments

State	Cost Variation
CT	6.0%
MA	-3.0%
ME	7.0%
NH	0.0%
RI	2.0%
VT	-1.0%

Figure 23: Battery Storage Capital Costs by Vintage



11.4.6 Canadian Hydro via New HVDC Ties

New Canadian hydro energy resources combined with new HVDC ties present a challenge in estimating project costs for inclusion in a least-cost capacity expansion model for two reasons. First, neither Québec large capacity hydro reservoir projects nor long-distance HVDC tie projects

[58] U.S. Energy Information Administration. *Capital Cost Estimates for Utility Scale Electricity Generating Plants*. November 2016. http://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf

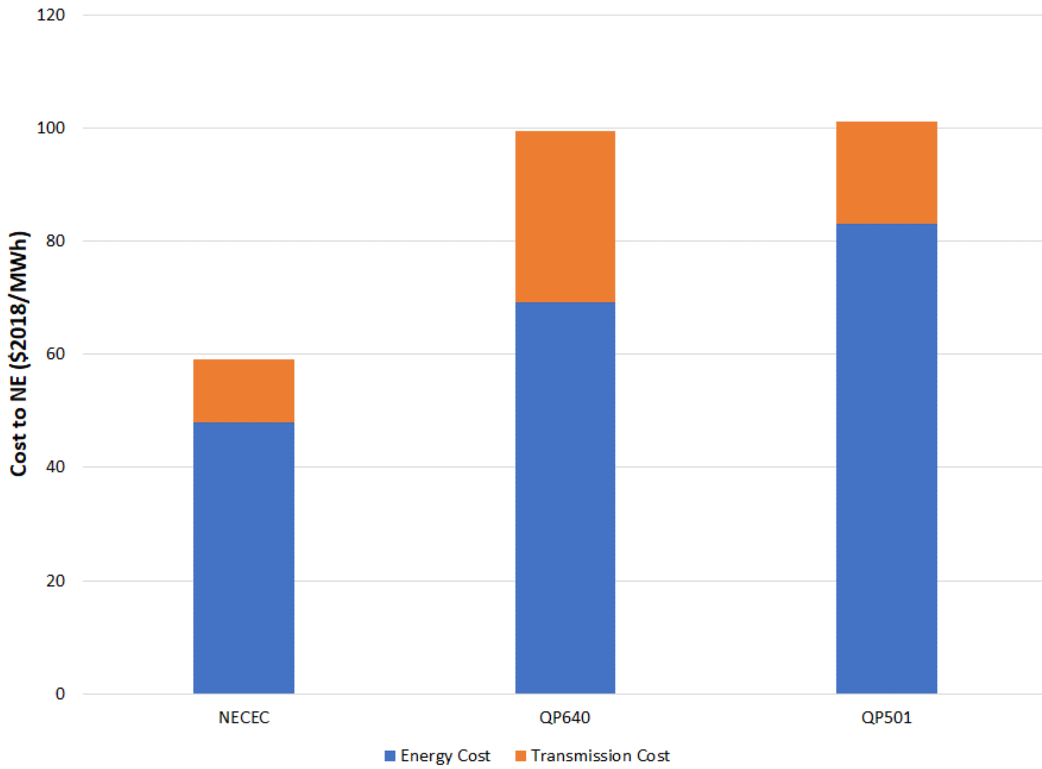
have off-the-shelf generic project costs. Second, New England customers would negotiate a PPA with Hydro-Québec, which has economic power to extract resource scarcity rent, up to the marginal willingness-to-pay by a New England customer. Two candidate HVDC tie projects were considered past the scheduled addition of NECEC: the Atlantic Link project (QP640) and the New England Clean Power Link project (QP501). Other import projects have stalled in development and withdrawn from the interconnection queue.

The NECEC Power Purchase Agreement and Transmission Service Agreements were both utilized to estimate contract costs for new Canadian hydro resources. Energy and transmission components of the contract costs were estimated separately and then combined to yield total contract costs. A decarbonization study co-authored by Hydro Quebec included levelized cost estimates for incremental hydroelectric generation based on bins of hydroelectric potential.[59] The leveled energy costs of the NECEC exports were calculated based on the assumption of a low present value of revenues over costs per HQ's low (3% nominal) cost of capital, and then the amount of various resource cost bins exhausted by NECEC was calculated through the implied weighted average of costs between the existing hydro bin and the first incremental hydro bin. Costs for candidate hydro resources were then escalated as further new hydro potential bins were exhausted. A 5% reduction was applied to the costs to New England as HVDC ties were modeled as having import/export flexibility rather than a rigid import scheduled from Canada to New England.

Transmission costs were scaled against the levelized contract costs found in NECEC's Transmission Service Agreement by comparing announced transmission construction costs of the proposed project against the NECEC announced costs of $1.1 billion. A 10% adder for contingencies was also applied to account for cost overruns that are often experienced as developers move further along in the permitting and construction process.

[59] Williams, J.H., Jones, R., Kwok, G., and B. Haley. *Deep Decarbonization in the Northeastern United States and Expanded Coordination with Hydro-Québec*. A report of the Sustainable Development Solutions Network in cooperation with Evolved Energy Research and Hydro-Québec. April 8, 2018. See Table 6. https://resources.unsdsn.org/deep-decarbonization-in-the-northeast-united-states-and-expanded-coordination-with-hydro-quebec

Figure 24: Projected HVDC Tie Line Costs to New England



QP640 was the first incremental HQ line considered and was treated as a scheduled addition in all scenarios but the Millstone Extension case. The SEMA injection point serves as a far better point of interconnection to offset the retirement of Millstone and other resources in load centers in Southern New England. QP501 was considered by Aurora as a candidate resource for addition.

11.5 Candidate Retirements

Most gas, oil and coal fueled generation resources were candidates for retirement. Some smaller units that may represent cogeneration or direct-use generation were exempted from inclusion, however. Candidates for retirement represent about one-half the installed nameplate capacity in ISO-NE.

Figure 25: Candidate Resources for Retirement by Technology Type

Technology Type	Nameplate Capacity (MW)
Coal	459
Combined Cycle	11,806
Combustion Turbine	2,597
Oil/Gas Steam	4,185
Total	**19,047**

12 Preliminary Production Cost Modeling

The Capacity Expansion runs used to generate expansion schedules used less sophisticated commitment logic. To refine the inputs for MARS modeling and improve final production cost modeling, intermediate model runs were conducted with more robust commitment logic. Intermediate Aurora simulations produced battery dispatch used to determine battery derate factors, gas demand used for gas pricing adjustments, and VER generation data utilized to set ancillary services requirements.

12.1 Battery Derate Factors

Battery storage resources needed to be derated, to reflect generation capability. The derate factors were calculated outside of Aurora, modeled on a seasonal basis (focusing on January and July Aurora hourly output).

The top ten peak periods (excluding weekends) were identified for January and July, for each storage unit, using Aurora hourly results. The available stored energy in batteries was identified at the beginning of each five-hour daily peak average load period for July, and three-hour daily peak period during winter months of each year.

For this subset of peak hours on peak days, battery average energy content values were converted into seasonal average derated generation capability values for MARS data input by storage duration and RSP subarea.

In large part, the winter derating values are higher than for summer because the winter peak period is only three hours long, versus five hours in summer. The maximum values that would be attainable if all batteries were fully charged at the start of the daily peak period is 80% in summer for the four-hour battery type and 40% for the two-hour type because the peak period is longer than their full generation duration capability.

The calculated summer and winter derate factors were then mapped into the MARS input file, for use in the MARS runs.

See Appendix 2, MARS Modeling, Section 1.13 for details on how battery energy storage resources were derated for average energy availability.

13 Final Production Cost Modeling

After Capacity Expansion runs were tuned per feedback from the MARS runs and run through intermediate production cost modeling again, refinements to gas pricing and operating reserves modeling were made for final production cost modeling.

13.1 Operating Reserves Modeling

The Study analyzed the probabilistic net effect of weather fluctuations on load together with wind and solar PV generation, and accounted for spatial diversity in loads and VER generation by area. The recently developed NREL "8760" method was used in this statistical analysis, applied to hourly data over a six-year period, 2007 to 2012, for which data are available for all three variables. This analysis was used to estimate the spinning, non-spinning, and load-following requirements to help ensure system reliability in the face of VER generation uncertainty.

This section summarizes the general procedure, specific assumptions, and data used for modeling operating reserves in Aurora. The operating reserves representation used in this Study is a more detailed structure than the traditional modeling in long-term studies. This modification is required to account for growing penetration of variable energy resources over the 20-year planning period.

13.1.1 Operating Reserves Method

Operating reserve requirements are modeled in Aurora as the sum of two components: current ISO-NE reserve product requirements and new requirements to reflect increased uncertainty in generation from wind and solar resources. These products and their requirements are shown in Table 16.

The current ISO-NE operating reserve requirements include four reserve capacity products:

- RegUp, (five-minute) regulation up reserve
- TMSR, ten-minute spinning reserve
- TMNSR, ten-minute non-spinning reserve
- TMOR, thirty-minute operating reserve.

In addition, three new requirements, additions to the RegUp and TMSR requirements and a new sixty-minute flexibility capacity (Flex) requirement and product that ISO-NE does not currently employ, were modeled to account for greater uncertainty in variable renewable energy (VRE) output in the future due to the growing penetration of wind and solar PV resources. The Flex product is similar in concept to the California ISO's flexibility product that was introduced in 2015.[60] The specific parameter values of these three requirements are based on constraints used by NREL in its ReEDS long-term planning simulation model. In addition to the sixty-minute Flex requirement based on the size of VRE hour-ahead forecast error, one-sixth of the VRE forecast error is added to the TMSR requirement, and 0.5% of hourly wind output and 0.3% of hourly solar PV output are added to the RegUp requirement.[61]

[60] The Flexible Resource Adequacy Criteria Must Offer Obligation (FRAC-MOO).

[61] Wind and solar PV regulation up requirements from NREL, *Regional Energy Deployment System* (*ReEDS) Model Documentation: Version 2018*, NREL/TP-6A20-72023. April 2019. https://www.nrel.gov/docs/fy19osti/72023.pdf Its Table 20 data are based on data developed in D. Lew et al. *The Western Wind and Solar Integration Study Phase 2*, NREL/TP-5500-55588. September 2013. https://www.nrel.gov/docs/fy13osti/55588.pdf

Table 16. Aurora Operating Reserve Requirements

System Requirement	Reserve Products to Satisfy Constraint	ISO-NE Requirement *	Wind Requirement	Solar PV Requirement	Time to Ramp (minutes)
Regulation Up	RegUp	Varies by hour, day type, and month	0.5% of generation	0.3% of generation	5
Total 10-minute operating reserve requirement (10MOR)	TMSR, TMNSR	120% of first largest source contingency	One-sixth of 60-minute VRE forecast error		10
10-minute spinning reserve requirement	TMSR	31% of 10MOR requirement	One-sixth of 60-minute VRE forecast error		10
Total operating reserve requirement (30MOR)	TMSR, TMNSR, TMOR	120% of first largest source contingency + 50% of second largest source contingency + replacement reserve	None		30
VRE forecast uncertainty	Flex	None	Varies (hour-by-month), based on 2 SD of persistence model VRE forecast error		60

* Sources for ISO-NE requirements:

1. The ISO-NE current year regulation requirements are provided in an Excel file at https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/daily-regulation-requirement
2. ISO-NE Market Operations memo, "Assumptions and Other Information for the Summer 2020 Forward Reserve Auction," March 18, 2020
3. ISO-NE Market Operations memo, "Assumptions and Other Information for the Winter 2019-2020 Forward Reserve Auction," July 22, 2019.

ISO-NE will *not* introduce these specific requirements, but in some form, additional requirements and products may eventually be implemented by ISO-NE once VRE's higher share of total generation would cause grid reliability challenges that warrant the design and use of new requirements and products. ISO-NE has studied the need for enhanced operating reserve requirements to ensure that there will be sufficient flexible generation to follow VRE generation for over a decade.[62] Recently, ISO-NE has studied the growing operating reserve needs to account for just-in-time resources, including fuel-limited supplies of natural gas and LNG, as well as wind and solar energy.[63]

Together, the TMSR and TMNSR products provide for the NERC and NPCC minimum requirement of providing reserves to meet 100% of the first largest single source contingency within 10 minutes. The NPCC also requires operating reserves to meet at least 50% of the second largest single source contingency within 30 minutes. ISO-NE currently requires an additional 20% of 10-minute reserves to account for generator non-performance, and that no more than 69% of the 10-minute reserves be from TMNSR. ISO-NE imposes a total operating reserves constraint that, in addition to first and second contingency reserves, also includes an additional TMOR requirement for replacement reserves.

In addition to ISO-NE system reserve requirements, currently there are locational operating reserve requirements for three reserve zones: NEMA/Boston, CT, SWCT. For practical modeling reasons, the system requirements were modeled in Aurora.

ISO-NE's current requirement that at least 31% of 10-minute operating reserves (10MOR) be provided by spinning reserves could be relaxed after substantial battery capacity is added to the system. Battery startup is highly reliable. Moreover, batteries can reach full output nearly instantly. To be conservative, the current ISO-NE requirement was not modified.

An example of 60-minute VRE forecast uncertainty for the Electrification Balanced Blend scenario results in the 20-year aggregate values by technology shown in Table 17. The positive and negative hourly MWh forecast errors across resource types are summed, which results in the system requirement being less than the sum of the requirements by individual resource type due to diversification of the weather aspects that drive uncertainty of each resource type. There is no forecast error during nighttime hours, so a better basis for comparing the relative forecast error reserve requirements by resource type than the all-hours average is the measure that only includes hours in a month when there is any generation. This effectively excludes nighttime hours for solar PV. The two average metrics are time-weighted, which would be expected to differ from generation-weighted average requirement ratios.

Table 17. 20-Year Statistics of 60-Minute Flexibility Reserve Requirement Ratios (Hourly Capability / Installed Capacity) for Electrification Balanced Blend Scenario

	LBW	OSW	UPV	BTM PV
Maximum	0.316	0.356	0.472	0.240
Average of All Hours	0.109	0.127	0.095	0.060
Average of Monthly Hours with Monthly Generation > 0	0.109	0.127	0.175	0.112

[62] For example, GE Energy, EnerNex, and ASW Truepower, *New England Wind Integration Study*. Final report prepared for ISO-NE. December 5, 2010. https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/newis_report.pdf

[63] For example, ISO-NE *2020 Regional Electricity Outlook*, pages 26-33.

The 60-minute flexibility requirement ratios differ slightly across the four initially-run scenarios because of their different annual capacity schedules by individual resource, as shown in Table 18.

Table 18. 20-Year Conditional (Monthly Generation > 0) Average of 60-Minute Flexibility Reserve Requirement Ratios (Hourly Capability / Installed Capacity)

	LBW	OSW	UPV	BTM PV
Base Reference	0.115	0.121	0.163	0.114
Base Balanced	0.123	0.120	0.190	0.114
Electrification Reference	0.115	0.121	0.163	0.114
Electrification Balanced	0.115	0.115	0.189	0.114

Together, Table 19 and Table 20 demonstrate how the contingency and replacement reserve parameters are transformed into the 10-minute operating reserve constraint, 10-minute spinning reserve constraint, and total operating reserve constraint values per the Forward Reserve Auction Assumptions memoranda furnished biannually by ISO-NE.

Table 19. First Contingency Requirement Parameters and Calculations

	First Largest Contingency (MW)	Non-Performance Adder	TMNSR Share	Total 10-minute Operating Reserve (10MOR) Constraint (MW)	TMSR Constraint (MW)
Winter 2019-20	1,669	20%	69%	2,003	621
Summer 2020	1,937	20%	69%	2,324	720

Table 20. Total Operating Reserve Requirement Parameters and Calculations

	Second Largest Contingency (MW)	50% Second Contingency Reserve (MW)	Replacement Reserve (MW)	Total TMOR (MW)	Total Operating Reserve Constraint (MW)
Winter 2019-20	1,252	626	180	806	2,809
Summer 2020	1,250	625	160	785	3,109

In its seasonal Forward Reserve Auction assumptions memoranda referenced in Table 16, ISO-NE has noted that "The local Forward Reserve requirements for each applicable Reserve Zone are based on the 95th percentile value from historical requirements data for the previous two like Forward Reserve Procurement Periods for each applicable Reserve Zone." The First Largest Contingency in ISO-NE is generally set by imports over the HQ Phase II HVDC line. Imports over Phase II vary significantly across seasons and therefore the 95th percentile value for the First Largest Contingency is significantly higher than the median value (around 1,600 MW in summer, for example). Therefore, 10MOR requirements tracked modeled imports from HQ, which are set based on representative weeks for each month calculated from historical import data (2017-2019), grossed up to include the 20% Non-Performance Adder. TMOR requirements set in the last two ISO-NE memoranda were projected as constant values for all years.[64]

13.1.2 Supply of Operating Reserves

The types of generator and demand resources capable of providing any of the operating reserve products are listed in Table 21. Wood waste and MSW resources are excluded from the AS contribution resource types. In Aurora, MSW plants are set to be must-run at full capability, as it is difficult (at this juncture) to appropriately determine opportunity costs for wood waste systems. This is because they are often procured under contract and have opaque underlying costs.

Table 21. Reserve Products and Categories of Providers

Reserve Product	Generators	Demand Resources
RegUp	Partially loaded online with automatic generation control (AGC)	N/A
TMSR	Partially loaded online	Pump storage pumping asset demand
TMNSR	Offline quick-start units (CT, diesel, hydro, PSH, battery) and additional partially loaded online	Non-pump dispatchable asset related demand (DARD)
TMOR	Online or offline; generally larger CTs, online CCs	Non-pump DARD
Flexibility	Online or offline; generally larger CTs, CCs, HVDC power import *	HVDC power export *

* LAI assumes that controllable HVDC ties will only be available for ISO-NE dispatch instructions beyond 30 minutes notice.

Flexibility availability parameters by generator type in Table 22 are based on the technology's ramp rate and the lead time for each of the three operating reserve capacity products, per Table 16.

[64] Although the Second Contingency value changes during Seabrook outages, there are several other facilities of similar size that would become the second contingency during those events such as Millstone Unit 3 (1,229 MW), NECEC (1,200 MW at full import capability), and other HQ Ties posed in LAI's projections.

Table 22. Flexibility Parameters

Generator Type	Ramp Rate (% capacity/minute)	Availability Upper Bound (% online capacity)[65]		
		Spinning	**Regulation**	**Flexibility**
SCGT	8	80	40	100
CCGT	5	50	25	100
Coal	4	40	20	100
Biopower	4	40	20	100
Oil/Gas Steam	4	40	20	100
Hydro	100	No Upper Bound		
Storage	100			

Source: NREL, *Regional Energy Deployment System (ReEDS) Model Documentation: Version 2018*. NREL/TP-6A20-72023. April 2019. See Table 21. Data for fossil-fired resources from A. Bloom et al. *Eastern Renewable Generation Integration Study*. NREL/TP-6A20-64472. August 2016.

Regulation services require investment in automatic generation control (AGC) equipment and the equipped generators have additional "mileage" costs when ramped up or down around a set point at all times. Regulation services were assumed to be provided by hydro, pumped storage, battery storage, CCGT, and coal units. SCGT, biopower, and landfill gas resources were assumed to not provide regulation services.[66] SCGT units do not operate enough hours to make AGC equipment investment attractive. Biopower and landfill gas units are small. Hence, adding AGC equipment is relatively more expensive per MW.

13.2 Gas Pricing Adjustments

The gas basis projection to New England was adjusted for each scenario using the methodology described in section 8.1 and the generator gas demands from the preliminary production cost modeling runs. The resultant basis projections are shown in the following figures. Figure 27 shows the full annual series for the original forwards and the two Reference Scenarios. Figure 27 and Figure 28 show only the average basis for January in each year for the Base Load Case Scenarios and Electrification Load Case Scenarios, respectively, in order to illustrate the differentials between Scenarios.

[65] Availability upper bound (% online capacity) = Min[RampRate (%/minute) * Ramp Requirement (minutes), 100%].

[66] Marissa Hummon et al. *Fundamental Drivers of the Cost and Price of Operating Reserves*. NREL/TP-6A20-58491. July 2013. See Table 3.

Figure 26: Algonquin Citygates Basis – Forwards vs. Reference Scenarios

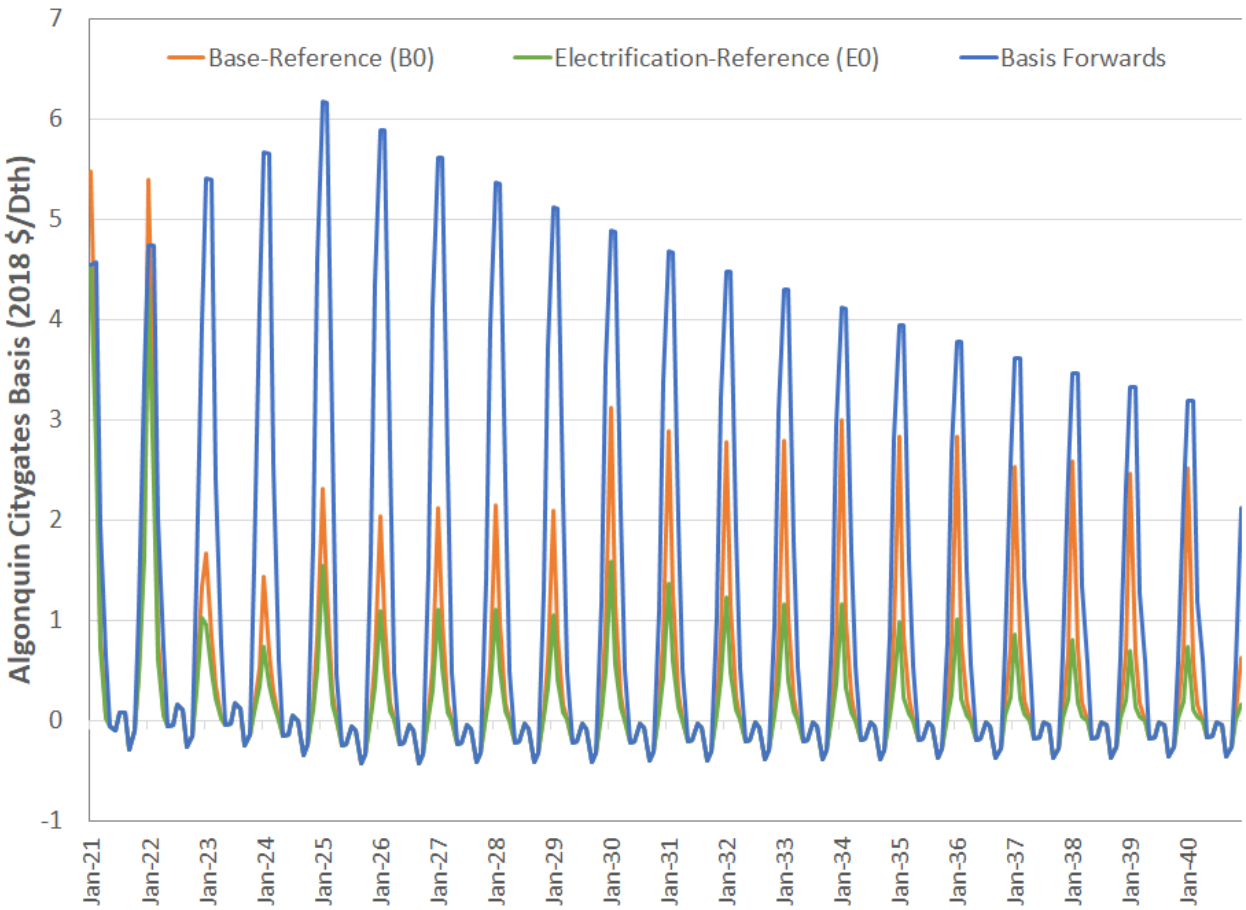


Figure 27: Revised Algonquin Citygates January Basis Projections, Base Load Case Scenarios

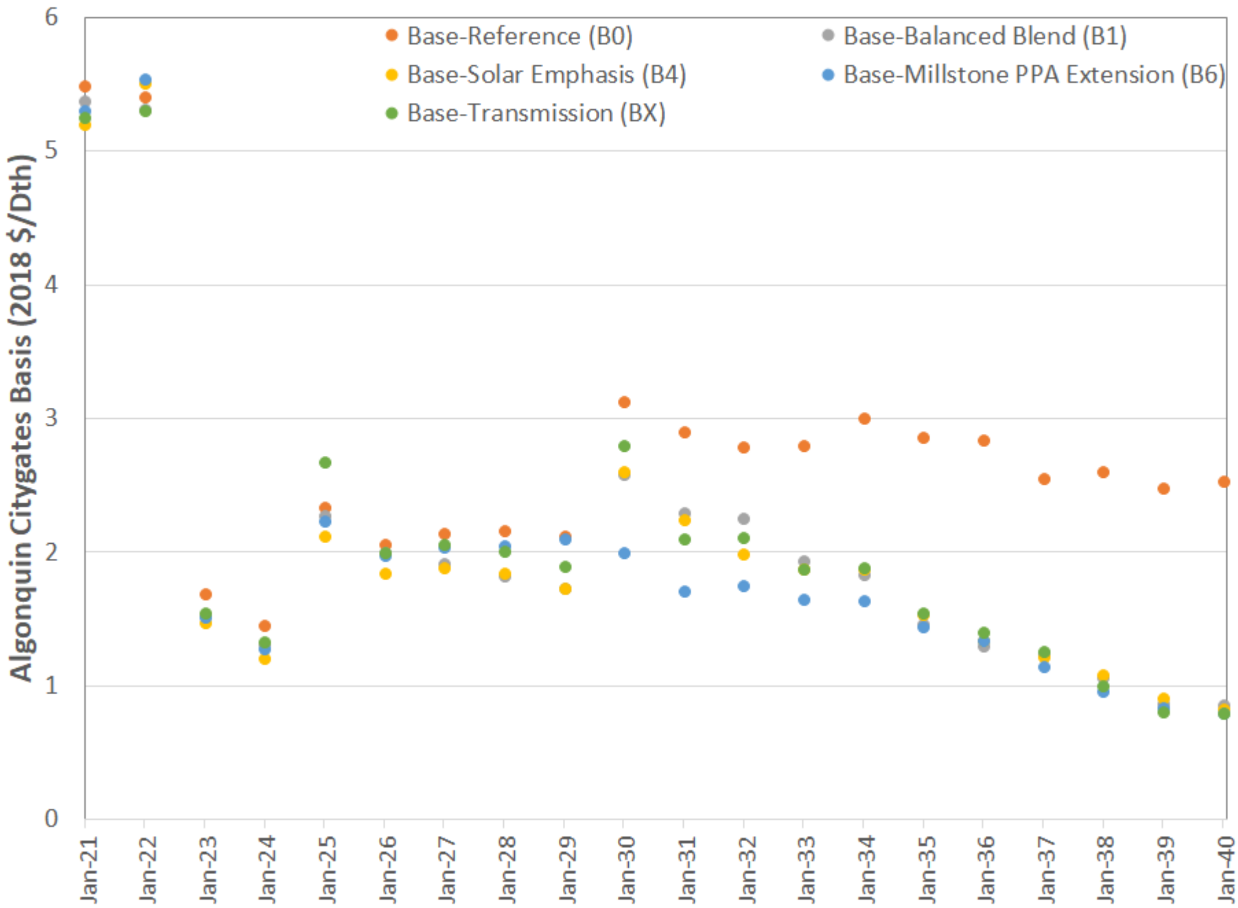


Figure 28: Revised Algonquin Citygates January Basis Projections, Electrification Load Case Scenarios