Appendix A3. Results

1 Capacity Expansion

As explained in Appendix 1, Aurora's long-term capacity expansion function was used to determine economic resource additions and retirements over the IRP planning horizon over and above known resource additions and retirements. The following charts reflect the resource balance after accounting for both scheduled and economic resource additions and retirements.

Figure 1 and Figure 2 provide an overview of total nameplate capacity by fuel type in 2040, the final year of the study period. The final resource mix for each scenario reflects the various retirements and additions resulting from the scenario capacity expansion. All Electrification load scenarios resulted in fewer retirements and increased OSW build out due to the higher load relative to the counterpart scenarios under the Base load case. As shown in Section 4.1, fossil generation declines over time, but capacity is still needed to meet resource adequacy needs.

Figure 1: 2040 Regional Capacity by Fuel Type, Base Load Scenarios

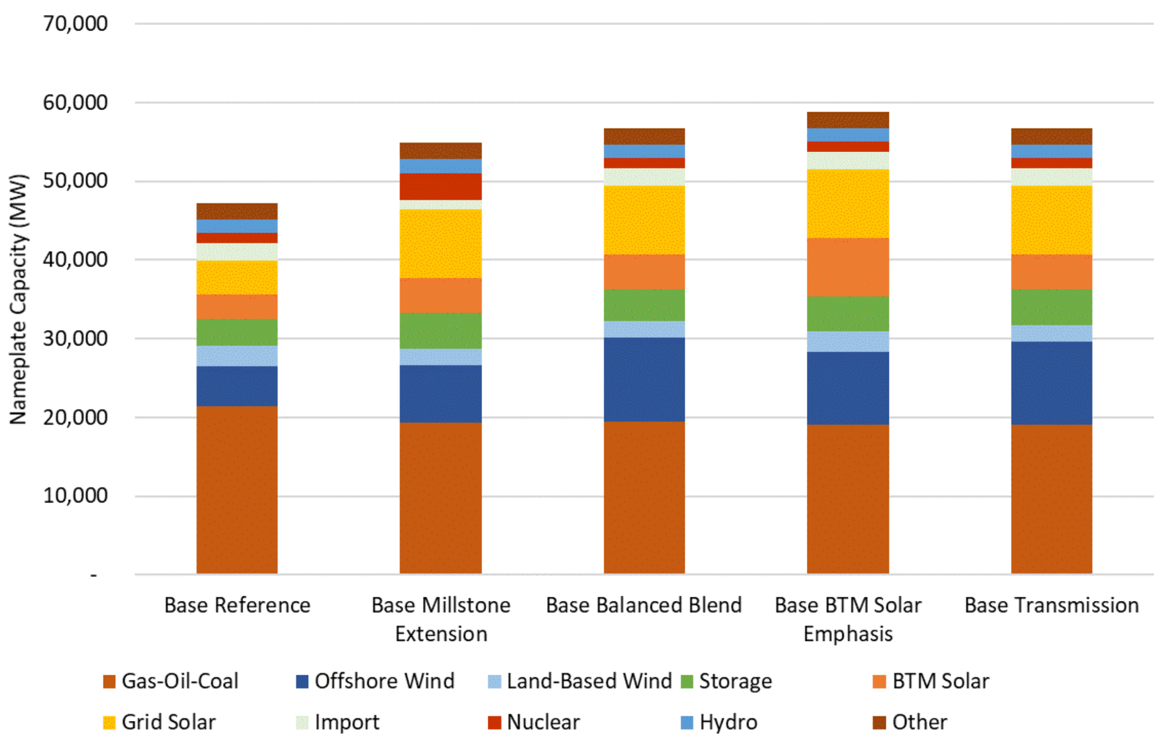
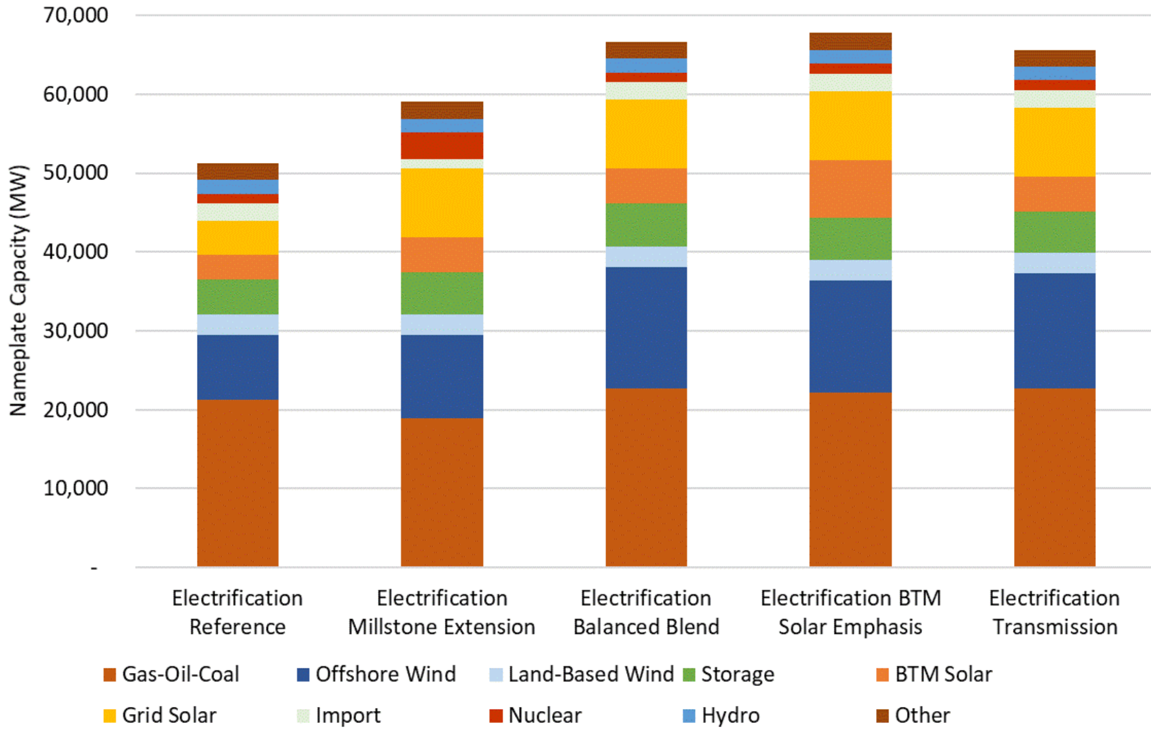


Figure 2: 2040 Regional Capacity by Fuel Type, Electrification Load Scenarios



The change in capacity over the study period is shown for all Base load scenarios in Figure 3 and for all Electrification load scenarios in Figure 4. Additions for each scenario are broken out by technology type. Retirements are shown in the aggregate. More detail on technology-specific retirements is shown in Figure 5 and Figure 6.

BTM Solar and import additions are identical for the two load cases across each resource case. In contrast, energy efficiency additions are varied across the two load cases but are held constant for the five scenarios. As previously noted, the largest disparities across load cases include higher levels of additions in scenarios under the Electrification load case, particularly OSW additions, and lower levels of retirements for Electrification load scenarios. Increasing planning reserve requirements in the Electrification load scenarios required that the capacity expansion built additional battery storage and reduced retirements relative to the corresponding Base load scenarios.

Figure 3: Cumulative Regional Additions and Retirements, Base Load Scenarios

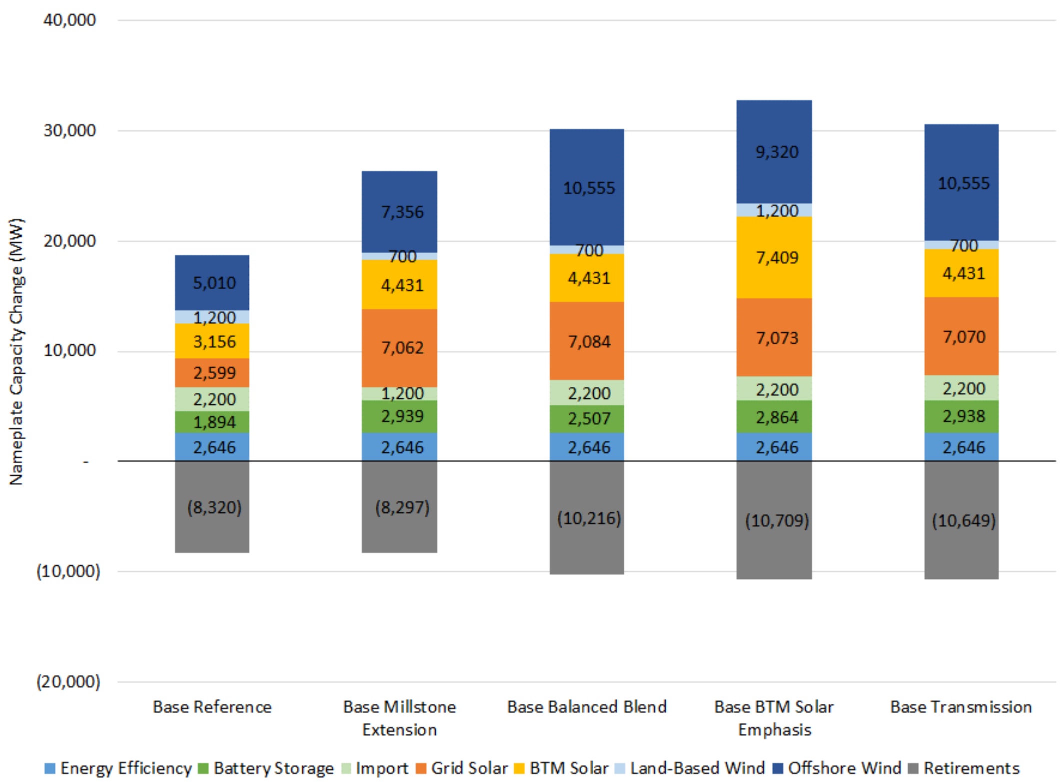
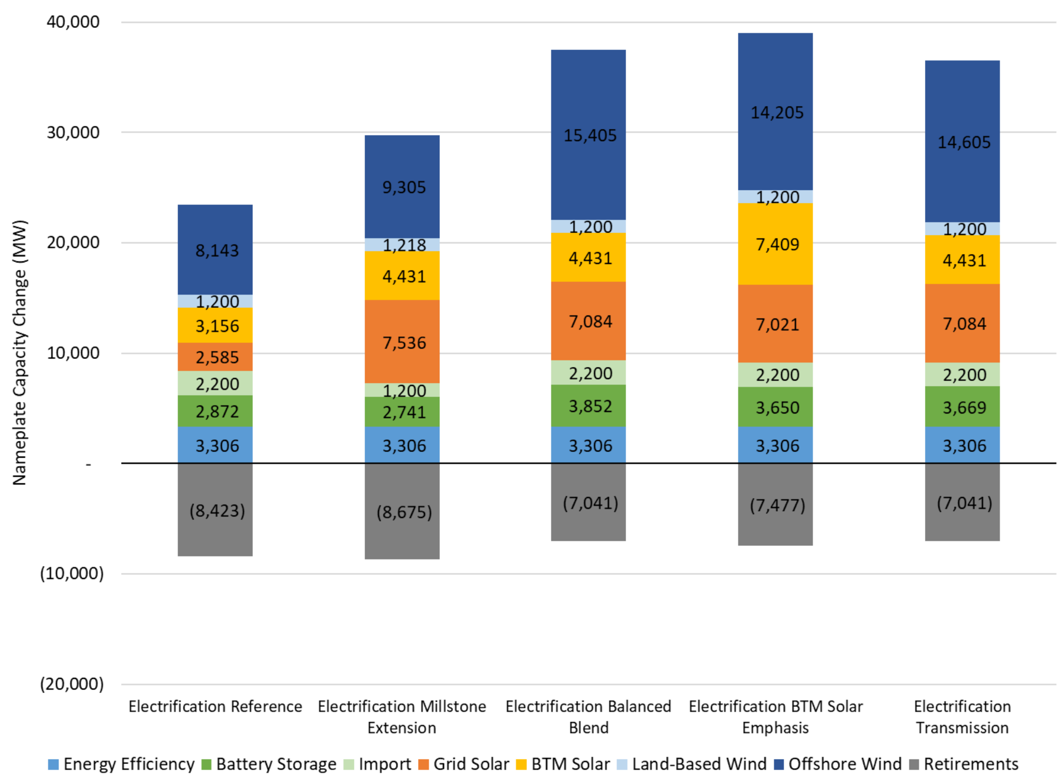


Figure 4: Cumulative Regional Additions and Retirements, Electrification Load Scenarios



Coal, Nuclear, and Refuse/Biofueled plant retirements are constant across the two load cases. There are fewer gas and oil-fired steam turbine plant retirements in the Electrification load scenarios as these resources are needed to meet resource adequacy. Likewise, there are fewer combined cycle retirements as more baseload generation is needed to ensure reliability under the higher load projection.

Figure 5: Total Regional Retirements, Base Load Scenarios

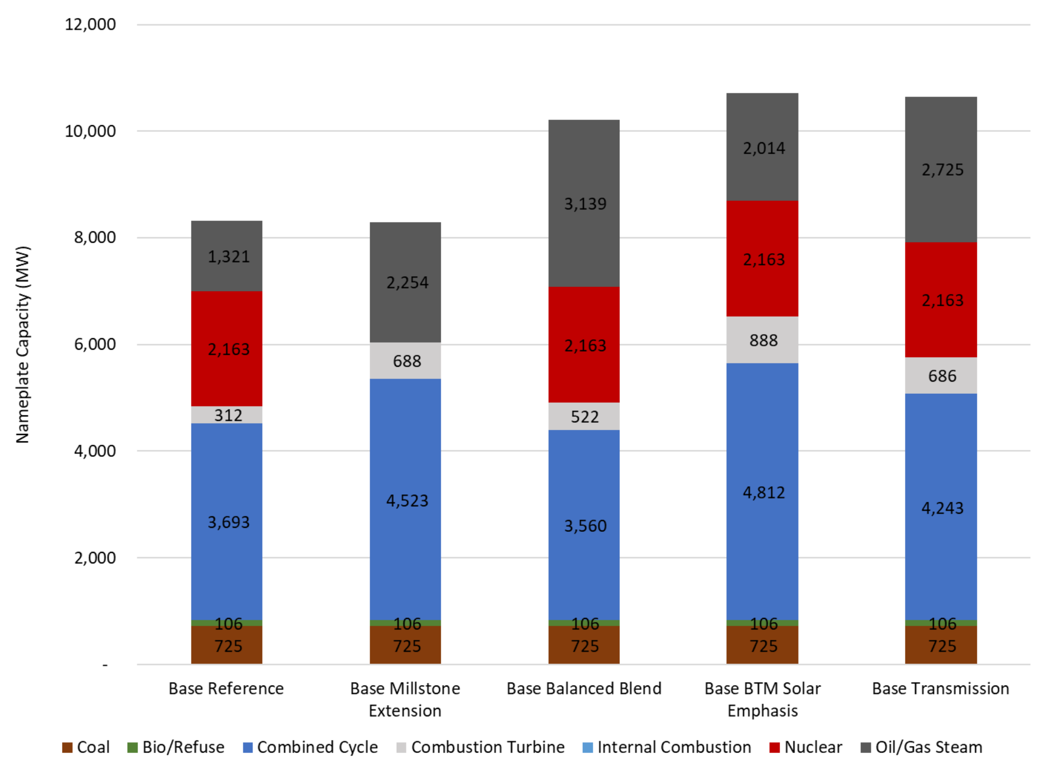
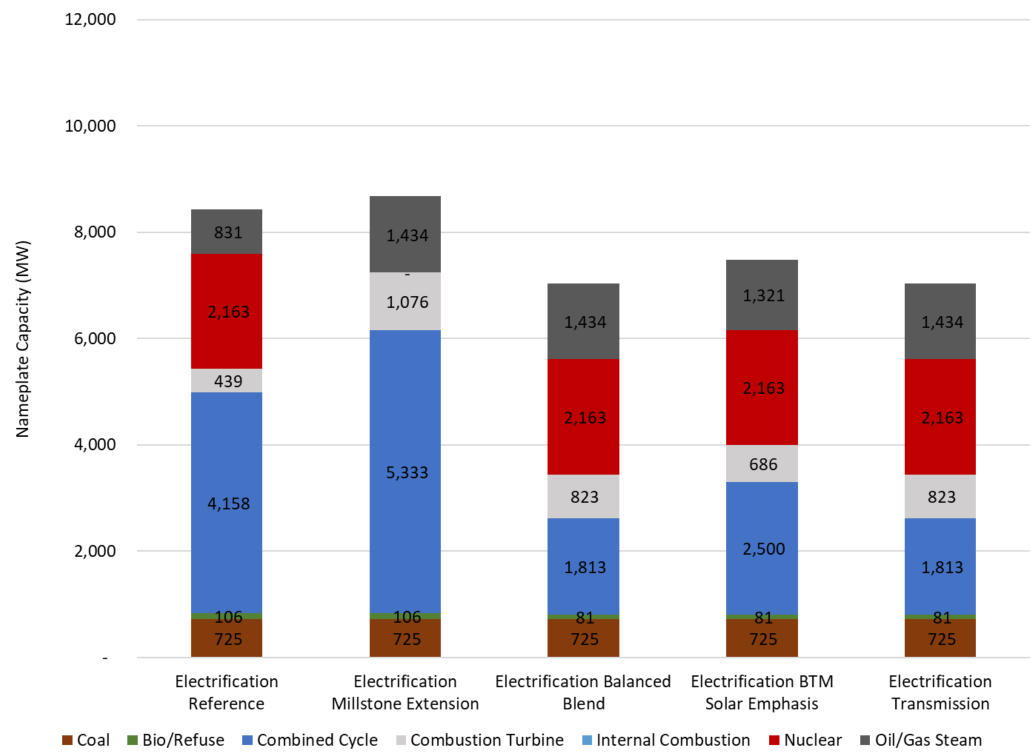


Figure 6: Total Regional Retirements, Electrification Load Scenarios



2 Operating Reserves

As addressed in Appendix 1, increased VER penetration increases the need for reserve products to account for forecast error. The demand for ancillary products was calculated based on VER generation in the expansion cases. In final production cost simulations, operating reserve products were included as operational constraints. Even with significant increases in demand for reserve products, operating reserve requirements were met for each scenario tested.

2.1 Reserve Product Demand Calculations

ISO-NE currently calculates 30-minute and 10-minute operating reserves per first and second contingency requirements as recommended by NERC. Regulation requirements are set via a 12x24 month-hour schedule set by ISO-NE. These initial requirements as set by ISO-NE were held constant among all scenarios, as none of the scenarios resulted in a material change to first or second contingencies. Further requirements were adopted to account for increased forecast error from VERs.

The Electrification load case has greater demand for reserve products, as shown by Figure 7 and Figure 8 for 60-minute flexibility reserves. This is because more VERs are needed to meet emissions targets when more load is added to the system. The Balanced Blend, BTM Emphasis, and Transmission scenarios all followed the same general demand trajectory as VER generation is similar. The Millstone Extension scenarios required less operating reserves than other policy scenarios since continued nuclear operation displaces a portion of total VER additions. The Reference scenarios required the least new operating reserves.

Figure 7: Flex Reserve Product Demand, Base Load Scenarios

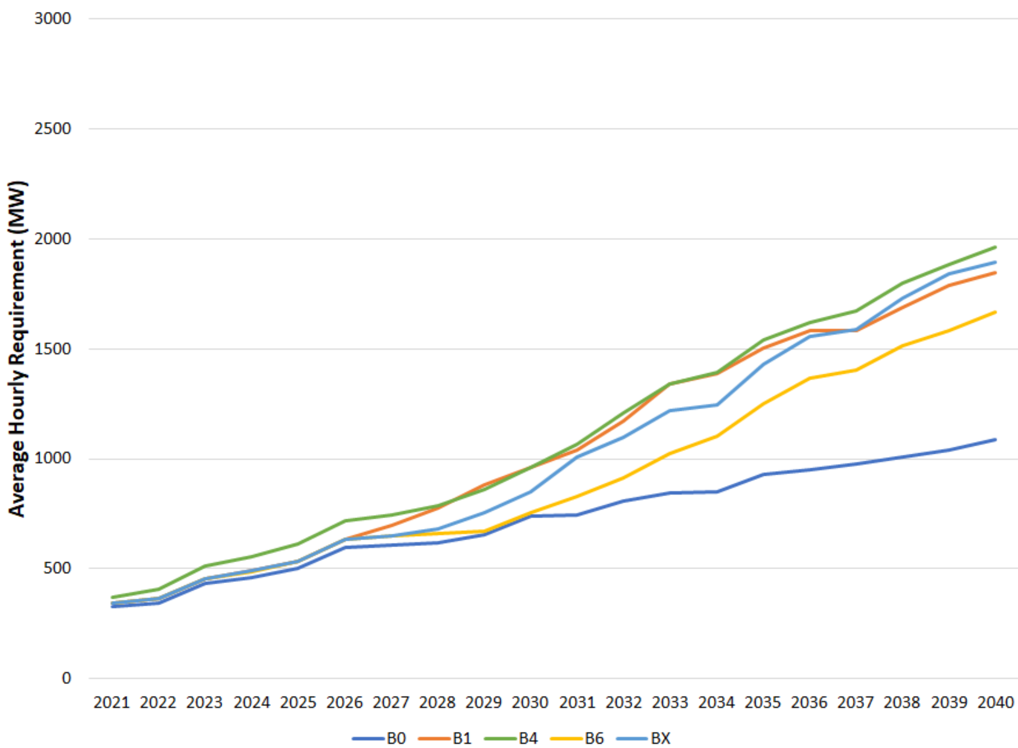


Figure 8: Flex Reserve Product Demand, Electrification Load Scenarios

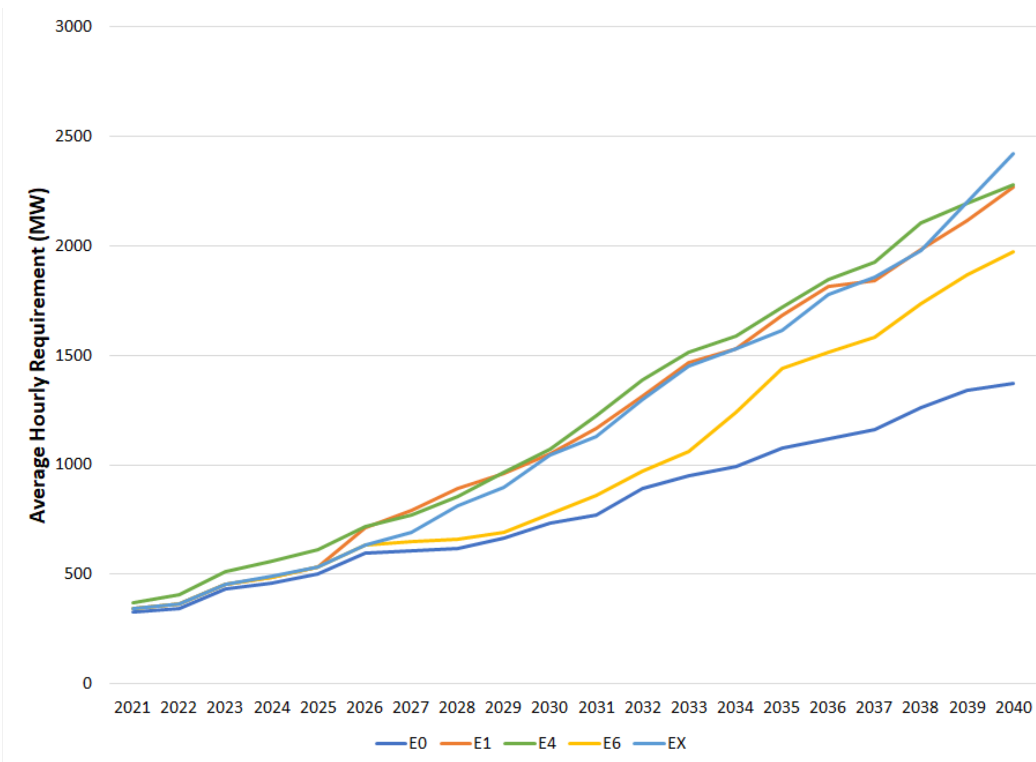


Figure 9: 10-Minute Spin Forecast Error Adjustment, Base Load Scenarios

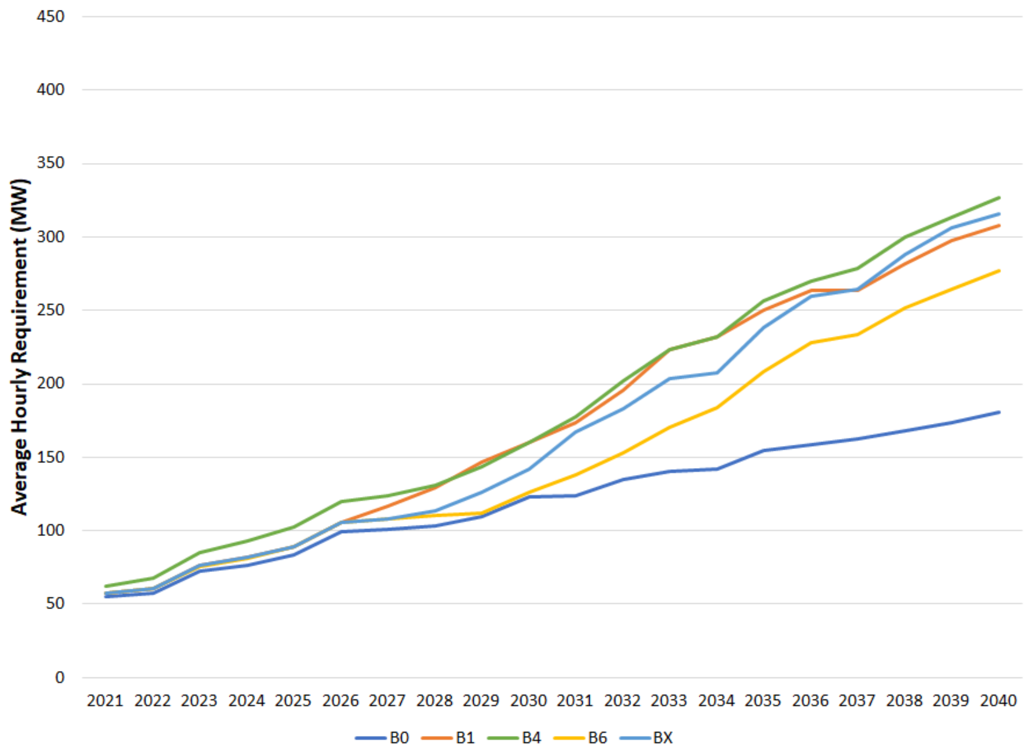


Figure 10: 10-Minute Spin Forecast Error Adjustment, Electrification Load Scenarios

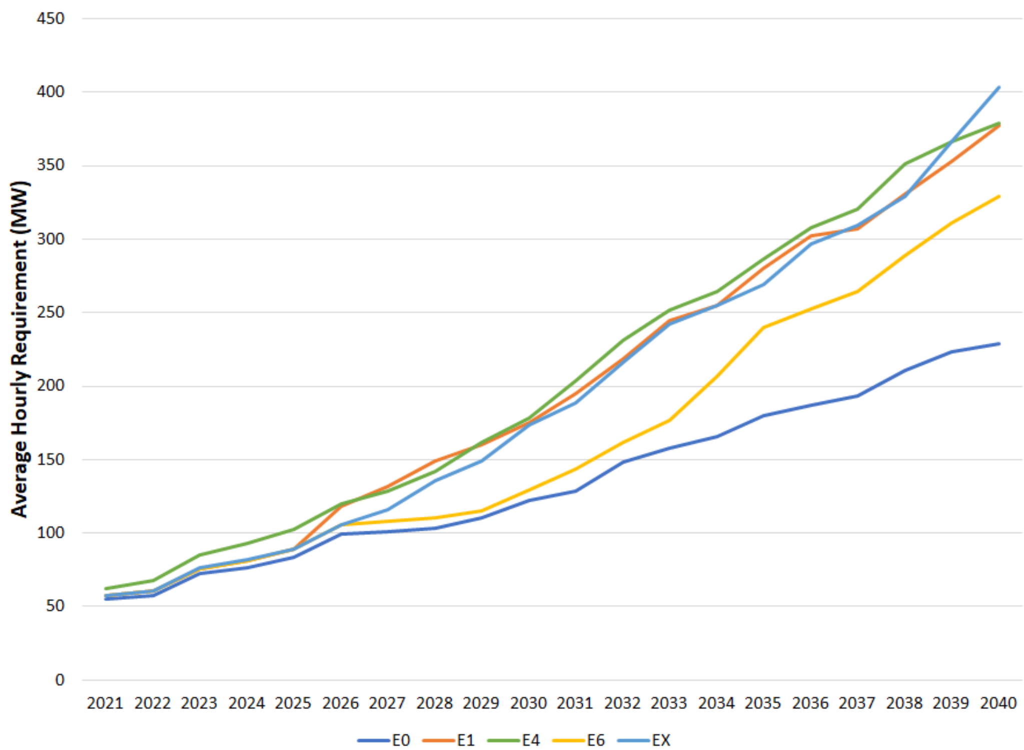


Figure 11: Regulation Forecast Error Adjustment, Base Load Scenarios

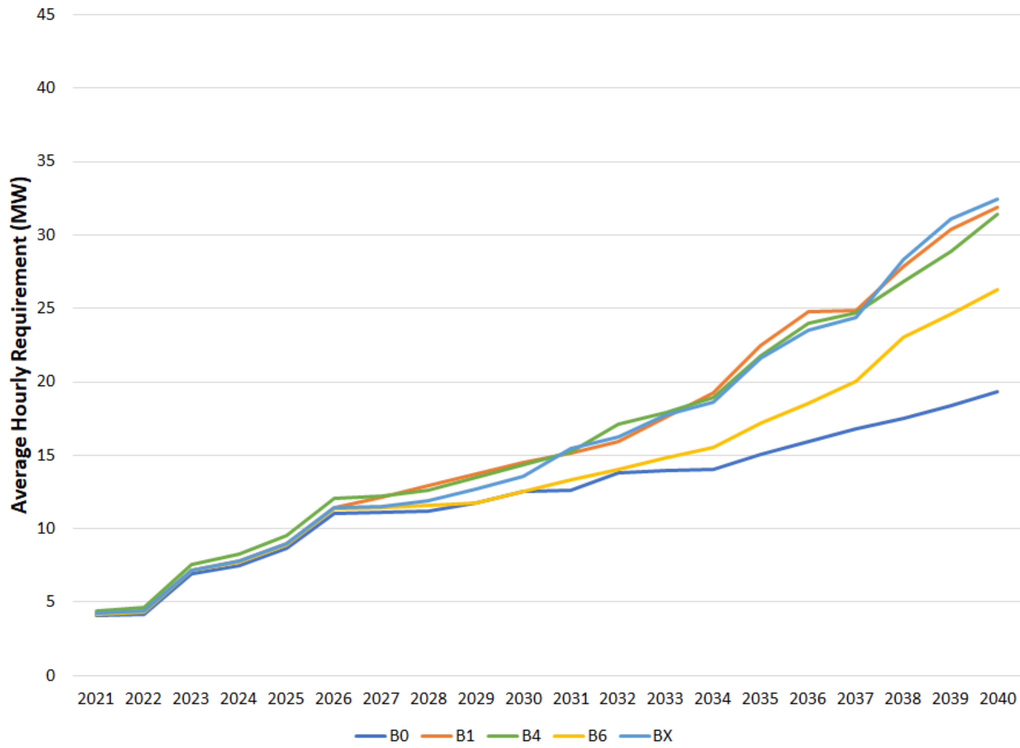
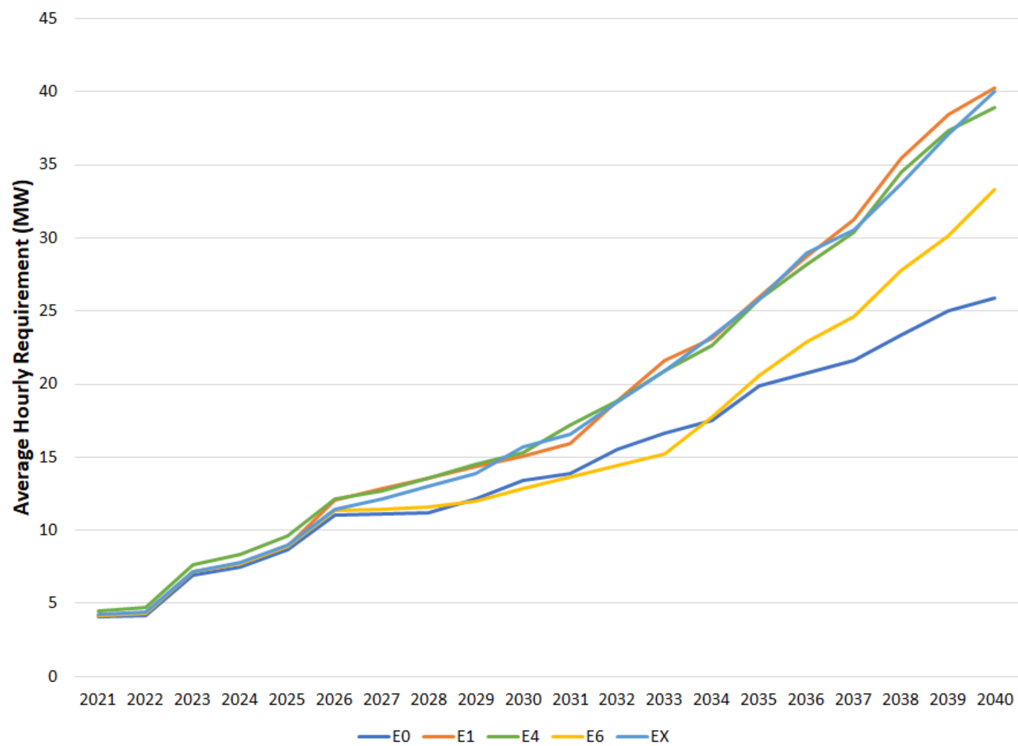


Figure 12: Regulation Forecast Error Adjustment, Electrification Load Scenarios



2.2 Reserve Product Resource Performance

Aurora results reveal how operating reserve requirements are met over time given increases to reserve targets and the changing system mix of dispatchable resources.[1]

Table 1: Average Operating Reserves Supplied by Technology, Base Reference Scenario, 2021
(Annual MWa)

Technology	RegUp	TMSR	TMNSR	TMOR	Flex	All Products
Active DR	0.0	0.0	180.9	97.7	23.4	302.1
Battery Storage	0.9	2.4	2.2	1.7	0.2	7.4
Coal	0.4	0.5	0.2	0.5	0.1	1.7
Combined Cycle	41.3	279.2	81.5	70.8	132.1	604.8
Combustion Turbine	0.0	0.0	709.2	476.1	153.9	1,339.2
Hydro	22.3	61.1	50.4	40.0	6.8	180.7
Oil/Gas Steam	0.0	0.1	0.0	0.0	0.0	0.1
Pumped Storage	28.9	238.6	148.0	112.1	13.9	541.5
Total	**93.8**	**581.8**	**1,172.4**	**799.0**	**330.5**	**2,977.6**

The Base Reference Scenario acts as a reasonable proxy for the rest of the studied scenarios at the beginning of the study period, as most changes to load and resources cannot occur and demand for reserve products nearly identical across the scenarios. For products that require spinning resources (RegUp and TMSR), about half of the requirements are provided by hydro and pumped storage resources and the other half is mostly provided by combined cycle resources. Products that do not require spinning resources are supplied in large part by combustion turbines.

Table 2: Average Operating Reserves Supplied by Technology, Base Reference Scenario, 2040
(Annual MWa)

Technology	RegUp	TMSR	TMNSR	TMOR	Flex	All Products
Active DR	0.0	0.0	159.0	108.5	84.5	352.0
Battery Storage	31.1	263.8	208.5	125.4	117.0	745.8
Coal	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	21.1	121.1	66.4	48.2	457.2	714.1
Combustion Turbine	0.0	0.0	515.9	367.5	309.4	1192.8
Hydro	24.9	73.0	53.7	39.1	29.6	220.3
Oil/Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	31.8	249.6	168.4	110.3	88.4	648.4
Total	**109.0**	**707.5**	**1171.8**	**799.0**	**1086.1**	**3873.4**

By 2040, battery resources have taken a significant share of spinning reserve supply from combined-cycle resources, which supply a significant portion of the incremental Flex requirement,

[1] RegUp = 5-minute Regulation Up; TMSR = 10-minute spinning reserve; TMNSR = 10-minute non-spinning reserve; TMOR = 30-minute operating reserve; Flex = postulated 60-minute flexibility reserve. The modeling of operating reserve requirements and supplies is described in Appendix 1, Section 13.1.

which roughly triples from 2021. Battery storage also supplies a significant portion of non-spin requirements and takes some of combustion turbines' share of supply. Active DR, hydroelectric, and pumped storage resources cede a small share of reserve supply to batteries, but their contribution is similar.

Table 3: Average Operating Reserves Supplied by Technology, Base Balanced Blend Scenario, 2040
(Annual MWa)

Technology	RegUp	TMSR	TMNSR	TMOR	Flex	All Products
Active DR	0.0	0.0	169.7	120.0	115.2	404.9
Battery Storage	44.3	376.5	247.7	143.7	199.0	1,011.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	14.7	86.1	37.5	25.5	937.7	1,101.5
Combustion Turbine	0.0	0.0	503.4	365.8	433.4	1,302.6
Hydro	30.1	96.6	56.5	38.5	39.9	261.5
Oil/Gas Steam	0.0	0.1	0.0	0.0	0.1	0.2
Pumped Storage	32.4	275.3	157.0	105.4	122.6	692.8
Total	**121.5**	**834.5**	**1,171.8**	**799.0**	**1,848.0**	**4,774.8**

In the Base Balanced Blend scenario, RegUp and TMSR requirements increase by roughly 30 MW and 250 MW, respectively. Flex requirements more than quintuple from 2021 to 2040. Battery storage supplies more than a third of spinning products and combined-cycle units are mostly pushed to providing the lowest-quality Flex product. Overall reserve product requirements increase by about 50%. Similar trends are observed in the Base BTM Emphasis and Base Transmission scenarios.

Table 4: Average Operating Reserves Supplied by Technology, Base BTM Emphasis Scenario, 2040
(Annual MWa)

Technology	RegUp	TMSR	TMNSR	TMOR	Flex	All Products
Active DR	0.0	0.0	167.6	122.5	122.4	412.5
Battery Storage	46.1	420.8	288.8	168.1	276.0	1,199.9
Coal	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	12.0	74.0	40.0	26.4	954.0	1,106.3
Combustion Turbine	0.0	0.0	460.1	339.6	420.4	1,220.1
Hydro	31.3	96.1	56.9	39.1	46.5	269.8
Oil/Gas Steam	0.0	0.3	0.0	0.2	0.3	0.8
Pumped Storage	31.8	261.8	158.5	103.1	139.8	694.9
Total	**121.1**	**853.0**	**1,171.8**	**799.0**	**1,959.5**	**4,904.4**

Table 5: Average Operating Reserves Supplied by Technology, Base Transmission Scenario, 2040
(Annual MWa)

Technology	RegUp	TMSR	TMNSR	TMOR	Flex	All Products
Active DR	0.0	0.0	155.8	119.8	110.8	386.4
Battery Storage	42.6	411.9	282.3	176.3	257.3	1,170.4
Coal	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	21.6	65.2	35.5	24.9	930.8	1,078.0
Combustion Turbine	0.0	0.0	487.4	338.9	424.7	1,251.0
Hydro	27.0	94.4	53.0	37.8	42.0	254.2
Oil/Gas Steam	0.0	0.1	0.0	0.1	0.1	0.3
Pumped Storage	30.9	270.5	157.8	101.2	127.9	688.4
Total	**122.1**	**842.1**	**1,171.8**	**799.0**	**1,893.6**	**4,828.6**

Demand for reserves does not grow as much in the Base Millstone Extension scenario compared to other clean energy policy scenarios, but overall demand for operating reserve products still grows by about 50%.

Table 6: Average Operating Reserves Supplied by Technology, Base Millstone Extension Scenario, 2040
(Annual MWa)

Technology	RegUp	TMSR	TMNSR	TMOR	Flex	All Products
Active DR	0.0	0.0	151.9	111.6	105.7	369.2
Battery Storage	44.9	411.0	304.0	183.0	249.6	1,192.4
Coal	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	11.2	70.4	33.7	25.2	763.5	904.1
Combustion Turbine	0.0	0.0	472.7	339.2	385.7	1,197.6
Hydro	28.1	81.6	52.9	37.5	39.6	239.8
Oil/Gas Steam	0.0	0.0	0.0	0.0	0.0	0.1
Pumped Storage	31.7	240.8	156.6	102.5	120.2	651.8
Total	**115.9**	**803.9**	**1,171.8**	**799.0**	**1,664.3**	**4,554.9**

Similar trends apply to the Electrification scenarios. Battery storage continues to gain share in supply for all products, with more than one-half of spinning reserves supplied by 2040 in the clean energy policy cases. In the Electrification Balanced Blend scenario, RegUp and TMSR requirements increase by roughly 35 MW and 320 MW, respectively. Aurora allocated operating reserves so that no requirements were left unserved, even in the more constrained Electrification scenarios.

Table 7: Average Operating Reserves Supplied by Technology, Electrification Reference Scenario, 2040
(Annual MWa)

Technology	RegUp	TMSR	TMNSR	TMOR	Flex	All Products
Active DR	0.0	0.0	139.4	109.3	96.2	344.9
Battery Storage	43.0	355.8	285.5	173.7	215.5	1073.6
Coal	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	17.8	88.9	51.7	37.1	520.8	716.4
Combustion Turbine	0.0	0.0	476.7	336.6	385.3	1198.6
Hydro	24.4	73.8	54.2	36.1	37.8	226.3
Oil/Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	30.3	236.9	164.3	106.2	117.7	655.3
Total	**115.5**	**755.4**	**1171.8**	**799.0**	**1373.3**	**4215.1**

Table 8: Average Operating Reserves Supplied by Technology, Electrification Balanced Blend Scenario, 2040
(Annual MWa)

Technology	RegUp	TMSR	TMNSR	TMOR	Flex	All Products
Active DR	0.0	0.0	140.1	110.9	120.7	371.7
Battery Storage	56.5	538.4	388.7	228.7	399.9	1612.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	9.8	45.1	30.1	19.7	1107.2	1212.0
Combustion Turbine	0.0	0.0	405.1	305.4	444.5	1155.1
Hydro	29.1	81.4	53.0	37.2	46.3	247.1
Oil/Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	34.5	239.1	154.7	97.0	146.7	672.1
Total	**129.9**	**904.0**	**1171.8**	**799.0**	**2265.4**	**5270.2**

Table 9: Average Operating Reserves Supplied by Technology, Electrification BTM Emphasis Scenario, 2040
(Annual MWa)

Technology	RegUp	TMSR	TMNSR	TMOR	Flex	All Products
Active DR	0.0	0.0	138.7	111.0	122.9	372.5
Battery Storage	54.3	540.8	362.1	217.6	407.9	1582.7
Coal	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	11.2	47.8	29.9	21.4	1083.5	1193.9
Combustion Turbine	0.0	0.0	438.0	309.8	467.5	1215.3
Hydro	29.1	82.3	53.1	38.5	48.3	251.3
Oil/Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	33.9	234.8	150.1	100.7	145.3	664.8
Total	**128.6**	**905.7**	**1171.8**	**799.0**	**2275.4**	**5280.5**

Table 10: Average Operating Reserves Supplied by Technology, Electrification Transmission Scenario, 2040
(Annual MWa)

Technology	RegUp	TMSR	TMNSR	TMOR	Flex	All Products
Active DR	0.0	0.0	140.1	111.9	126.3	378.3
Battery Storage	54.9	564.5	390.3	223.4	430.0	1663.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	9.9	44.2	29.2	20.4	1199.6	1303.2
Combustion Turbine	0.0	0.0	405.2	305.2	460.9	1171.3
Hydro	29.3	81.2	52.0	36.5	48.9	248.0
Oil/Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	35.6	239.6	155.0	101.5	152.6	684.3
Total	**129.7**	**929.5**	**1171.8**	**799.0**	**2418.2**	**5448.3**

Table 11: Average Operating Reserves Supplied by Technology, Electrification Millstone Extension Scenario, 2040
(Annual MWa)

Technology	RegUp	TMSR	TMNSR	TMOR	Flex	All Products
Active DR	0.0	0.0	152.7	132.5	130.3	415.5
Battery Storage	51.2	483.3	378.0	217.4	391.0	1520.8
Coal	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	11.2	62.1	33.6	22.3	850.9	980.0
Combustion Turbine	0.0	0.0	395.3	289.6	399.6	1084.5
Hydro	28.1	79.7	53.0	37.1	48.2	246.1
Oil/Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	32.4	230.3	159.3	100.2	153.1	675.3
Total	**123.0**	**855.3**	**1171.8**	**799.0**	**1973.0**	**4922.1**

3 Gas Demand

Figure 13 shows the monthly generator gas demand from Aurora for the Base Reference Scenario and the Electrification Reference Scenario relative to historical generator gas demand.

Figure 13: Monthly Generator Gas Demand, Reference Scenarios and Historical

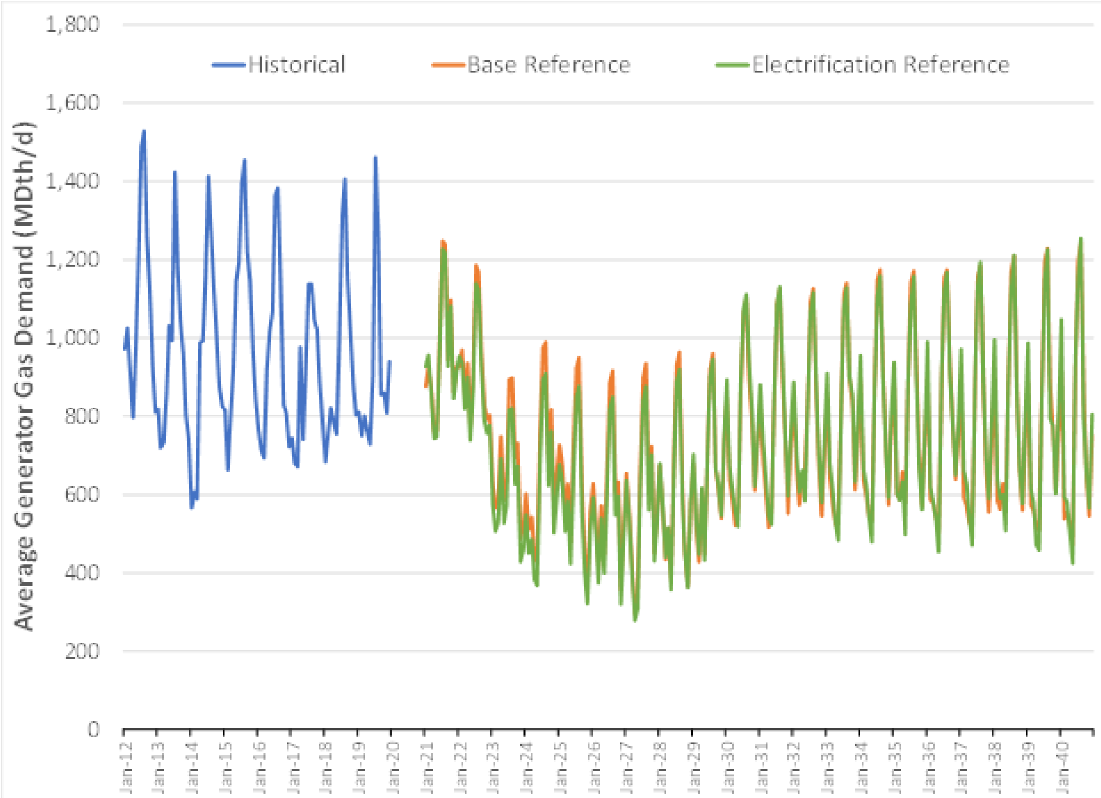


Figure 14 shows the total monthly gas demand, including both generator gas demand from Aurora and estimated utility sector gas demand based on the ASHP penetration levels presented in Appendix 1.

Figure 14: Total Monthly Gas Demand, Reference Scenarios

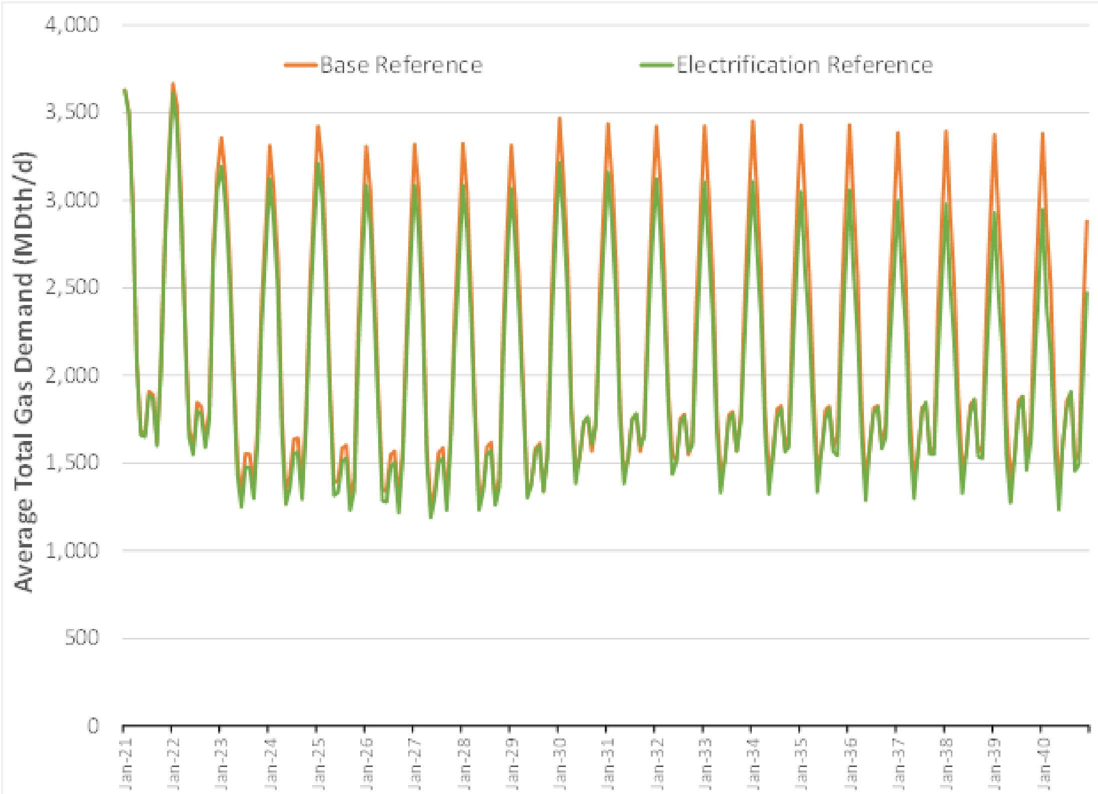


Figure 15 and Figure 16 show the monthly generator demand from Aurora for all Base Load scenarios and all Electrification Load scenarios, respectively.

Figure 15: Monthly Generator Gas Demand, Base Load Scenarios

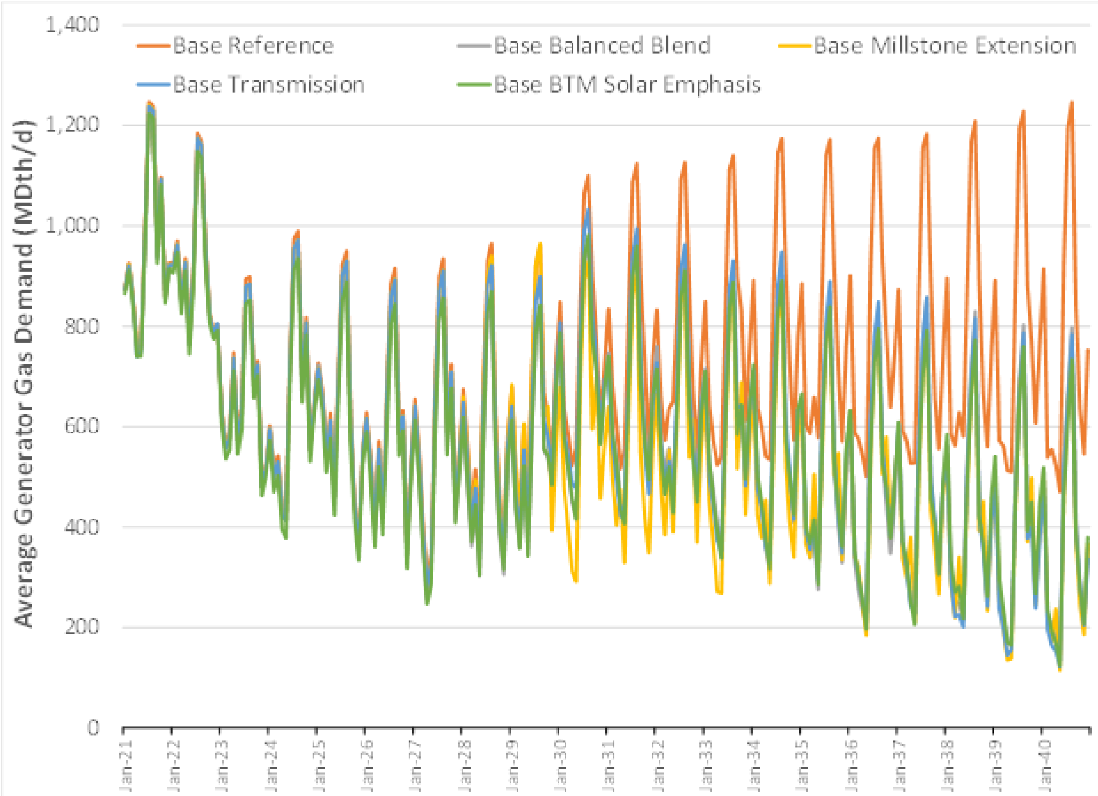


Figure 16: Monthly Generator Gas Demand, Electrification Load Scenarios

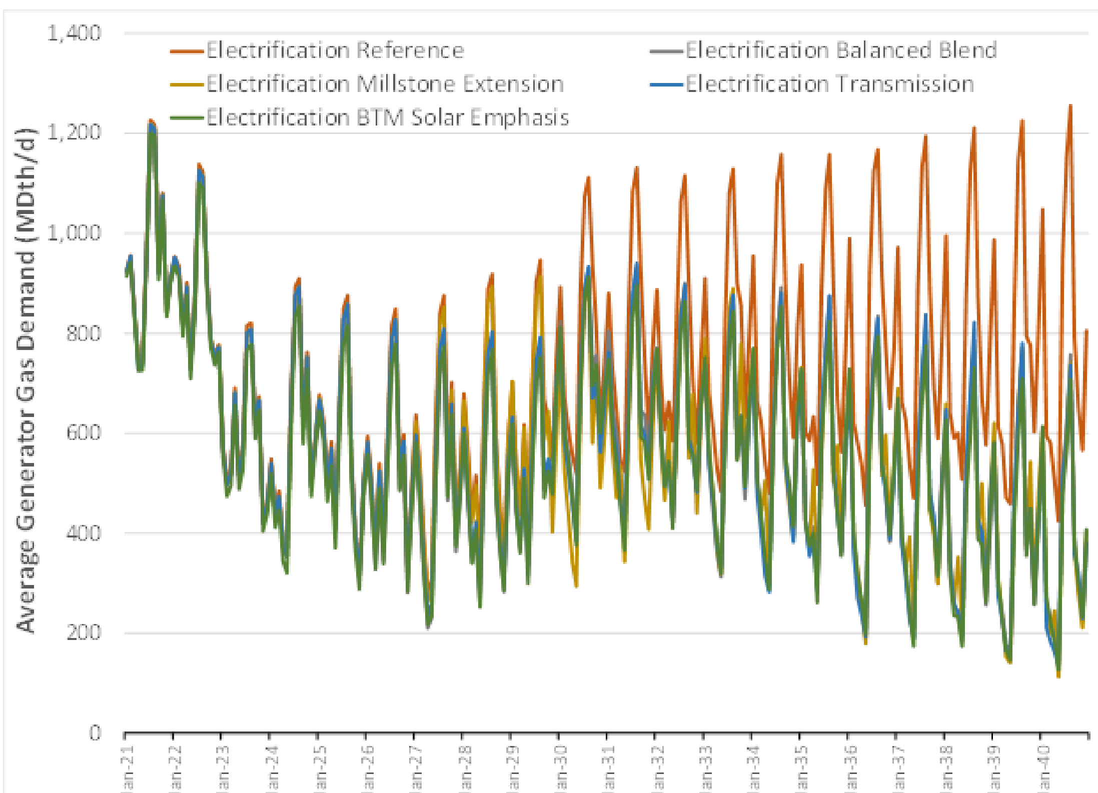


Table 12 details the percentage change in selected years relative to 2019 in annual generator gas demand for each scenario.

Table 12: Change in Annual Generator Gas Demand Relative to 2019 by Scenario

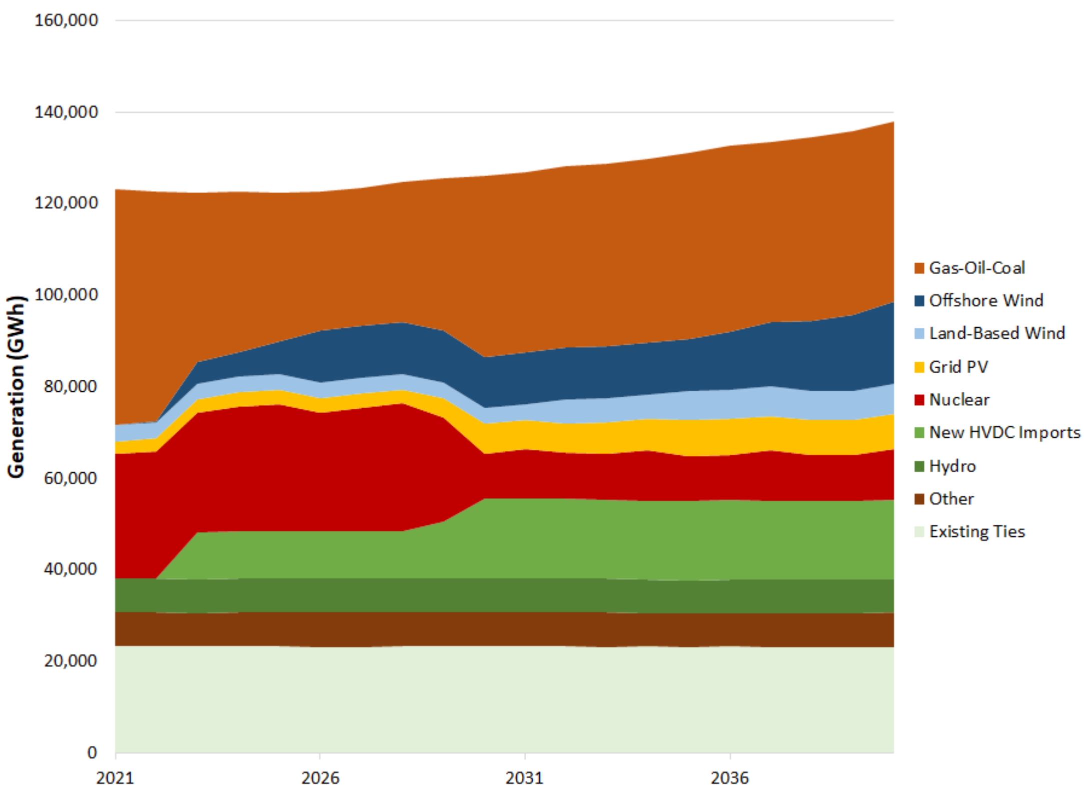
Scenario	2025	2030	2035	2040
Base Reference	-30.0%	-16.1%	-13.4%	-16.4%
Base Balanced Blend	-31.6%	-25.9%	-44.6%	-58.6%
Base Millstone Extension	-31.6%	-36.3%	-43.1%	-61.0%
Base Transmission	-31.7%	-21.7%	-42.7%	-60.8%
Base BTM Solar Emphasis	-35.3%	-25.6%	-43.4%	-60.7%
Electrification Reference	-36.1%	-13.8%	-15.1%	-14.7%
Electrification Balanced Blend	-37.6%	-25.0%	-41.6%	-57.9%
Electrification Millstone Extension	-37.6%	-34.5%	-40.5%	-58.9%
Electrification Transmission	-37.6%	-28.0%	-41.9%	-59.9%
Electrification BTM Solar Emphasis	-41.2%	-26.8%	-43.2%	-59.0%

4 Regional Generation

4.1 Annual Scenario Comparison

In all scenarios, clean energy generation increases to meet emissions goals while accommodating increasing demand. Differences between resource portfolio case assumptions affect which technologies are selected in capacity expansion and in turn affect generation totals.

Figure 17: Annual Regional Generation, Base Reference Scenario[2]



In the Base Reference Scenario, fossil generation is largely unchanged over the Study Period after the addition of NECEC in 2023. Wind, solar, and HVDC additions combine to offset the loss of Millstone and accommodate load growth while meeting the RGGI goal over the Study Period.

In the Base Balanced Blend Scenario, Gas-Oil-Coal resource output drops from 51 TWh in 2021 to 19 TWh in 2040 in response to region-wide emissions targets (Figure 18). Offshore wind and solar buildout above and beyond the Reference scenario are the main sources of substituted energy. Offshore wind meets about one-quarter of metered load in 2040. Canadian imports, particularly from New Brunswick, are curtailed due to clean energy development and low prices in Northern New England, which are caused by export constraints at the Maine- New Hampshire and North-South interfaces. Similar trends occur in the BTM Emphasis scenario, with reduced metered load not pictured in Figure 19 paring back the need for increased offshore wind generation.

[2] The "Other" category aggregates many different technologies. The majority of "other" is wood waste and municipal solid waste units.

Figure 18: Annual Regional Generation, Base Balanced Blend Scenario

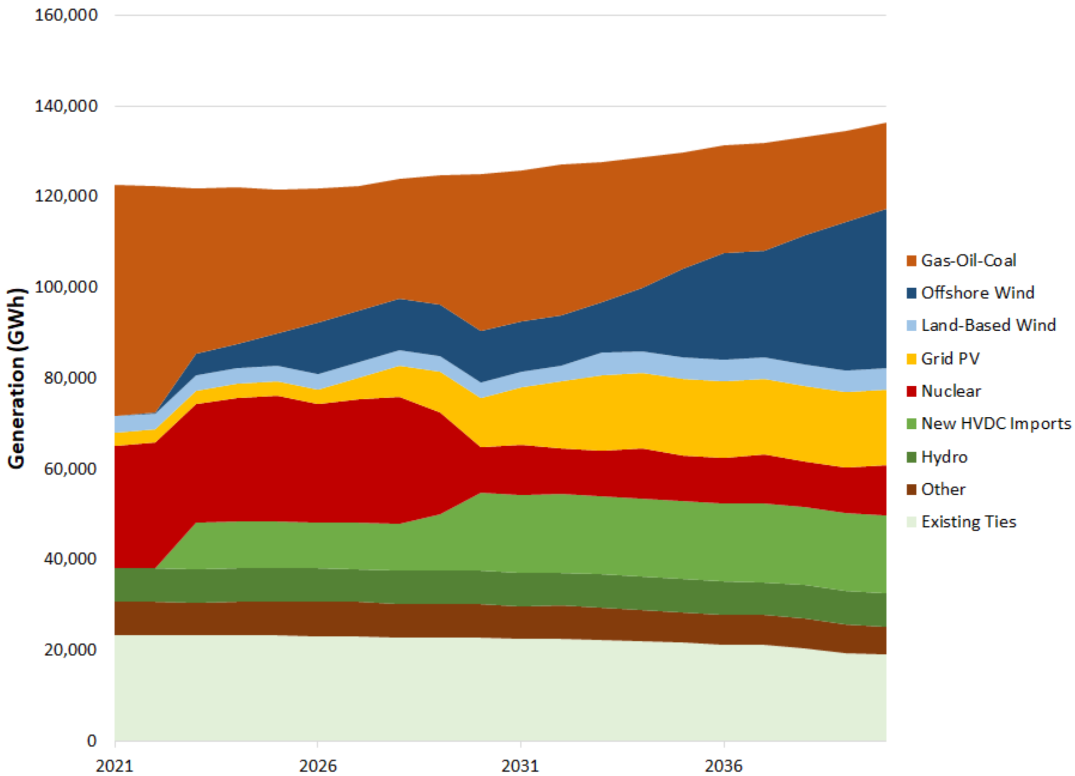


Figure 19: Annual Regional Generation, BTM Emphasis Scenario

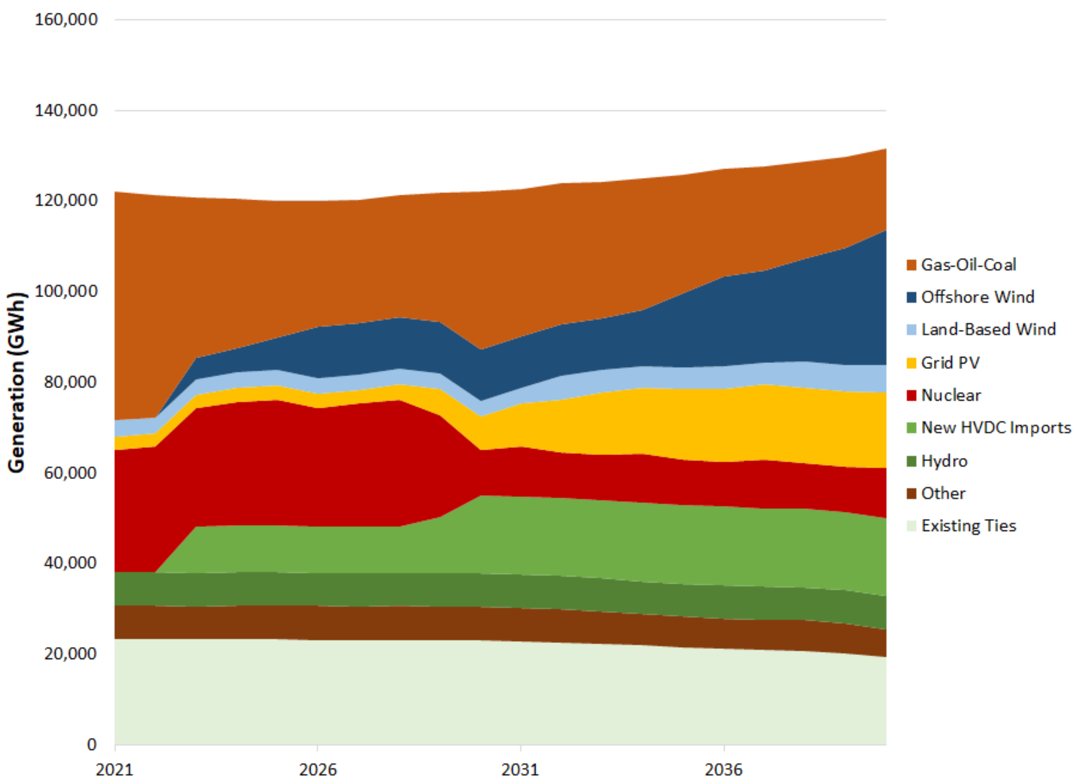
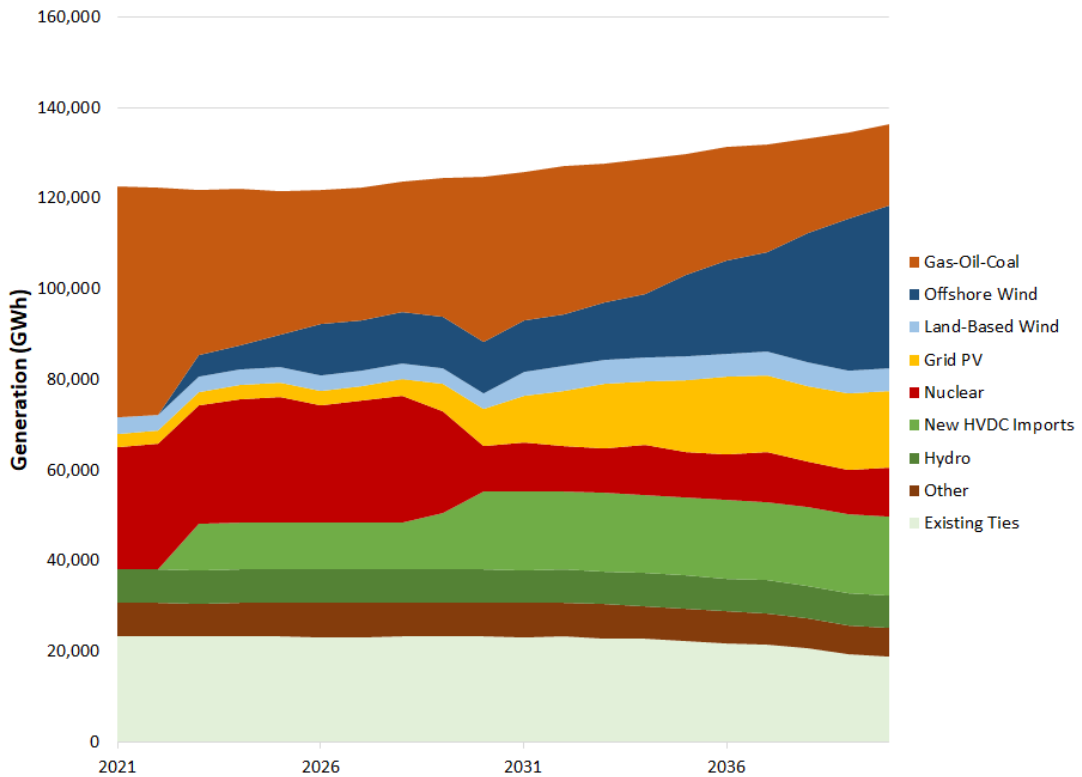


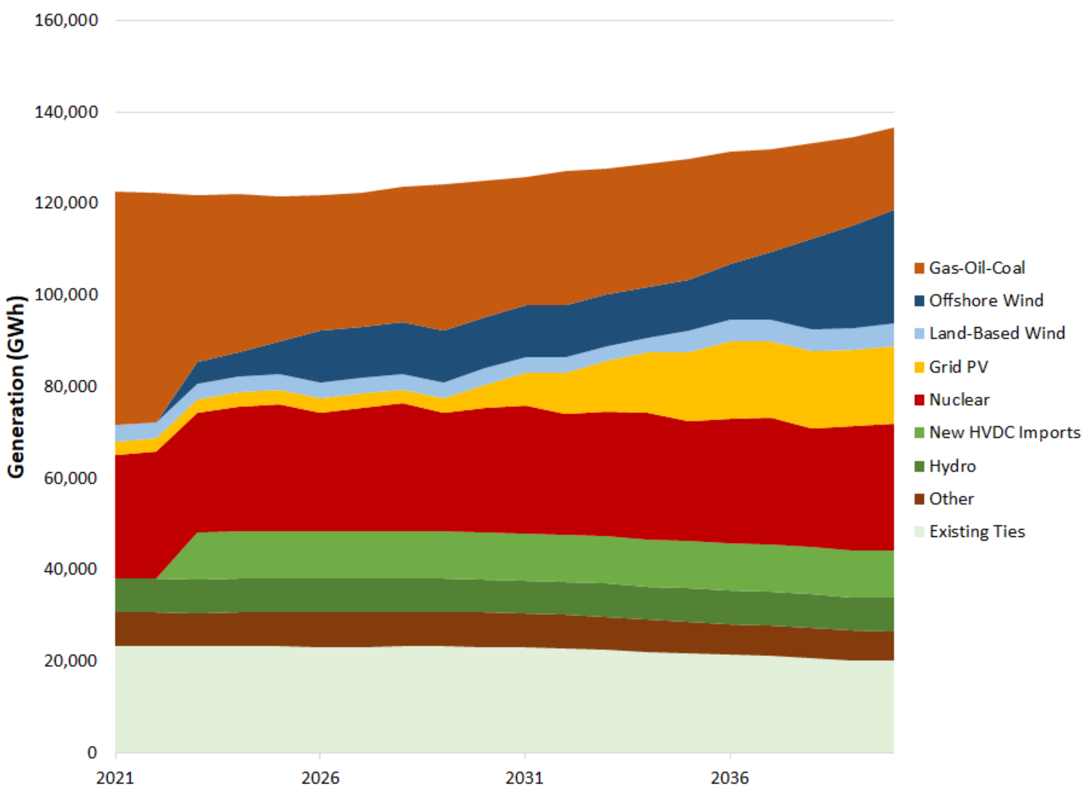
Figure 20: Annual Regional Generation, Base Transmission Scenario



The Base Transmission Scenario is nearly identical to the Base Balanced Blend scenario (Figure 20). Some reduction in Canadian imports still occurs even with transmission constraints relaxed.

In the Millstone Extension Scenario, shown by Figure 21, the continued operation of the facility means that no HVDC tie line is added after NECEC, and significantly less offshore wind generation is needed to meet regional emissions goals. Slightly less reduction in Canadian imports occurs, as flows from Northern New England to Southern New England are less congested.

Figure 21: Annual Regional Generation, Base Millstone Extension Scenario



Similar trends occur in the corresponding Electrification load scenarios. Even given less stringent regional carbon reduction goals in the Electrification Reference Scenario, grid-scale wind and solar make up almost 30% of metered load in 2040 (Figure 22). More clean energy is needed in all Electrification scenarios to offset increases to load due to beneficial electrification. In the Electrification Balanced Blend Scenario, offshore wind supplies about one-third of metered load (Figure 23).

Figure 22: Annual Regional Generation, Electrification Reference Scenario

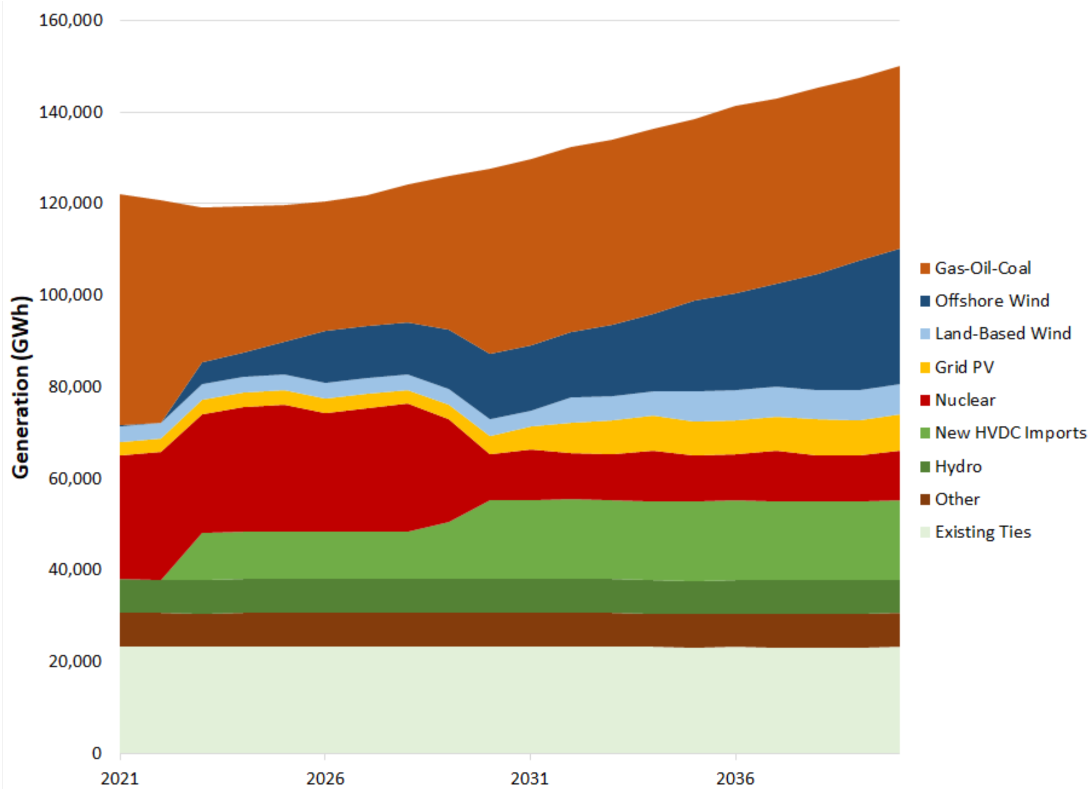


Figure 23: Annual Regional Generation, Electrification Balanced Blend Scenario

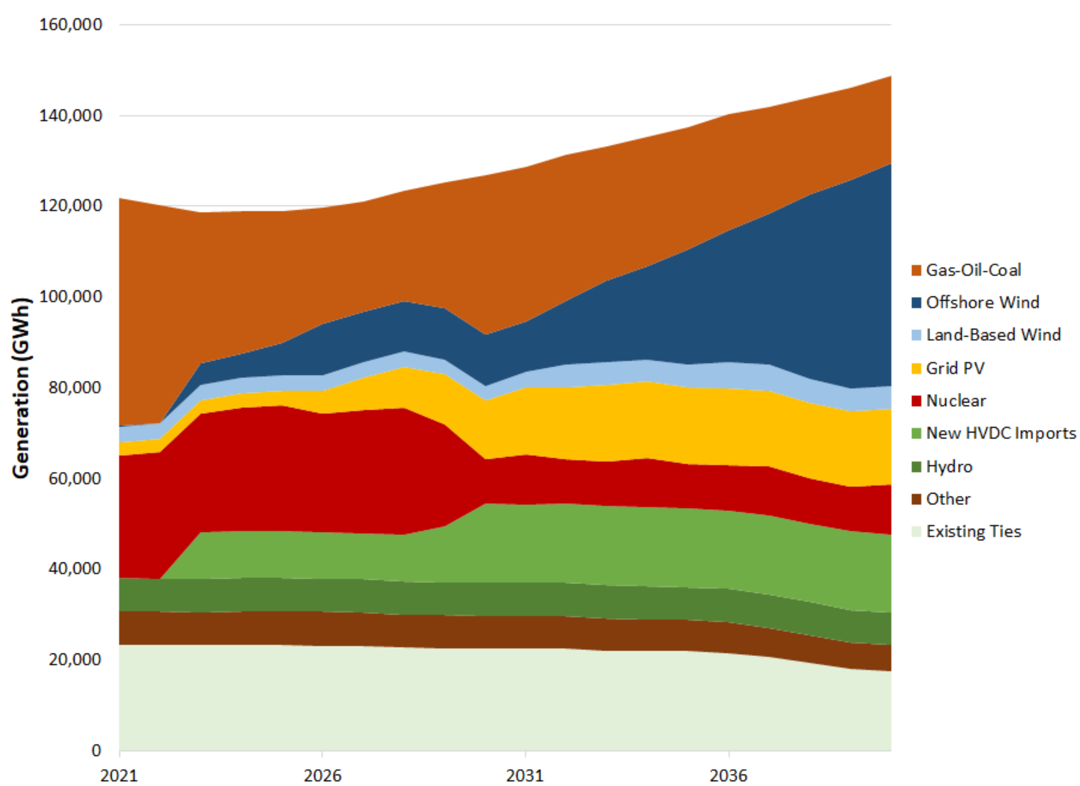


Figure 24: Annual Regional Generation, Electrification BTM Emphasis Scenario

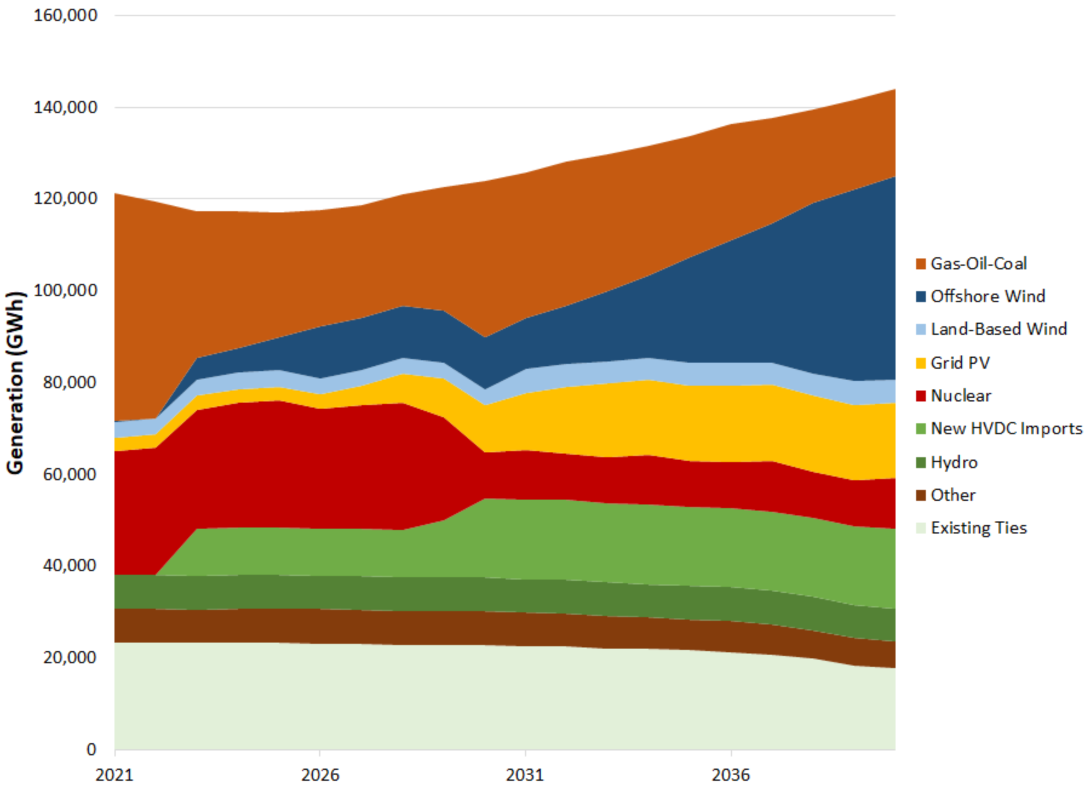


Figure 25: Annual Regional Generation, Electrification Transmission Scenario

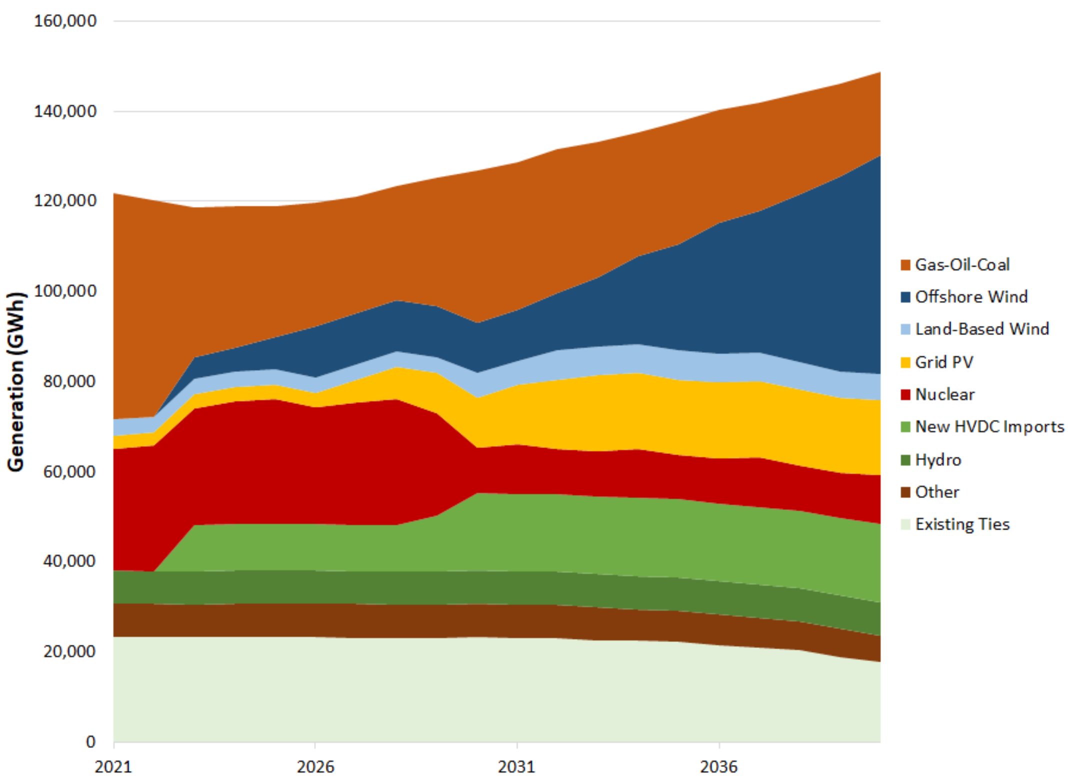
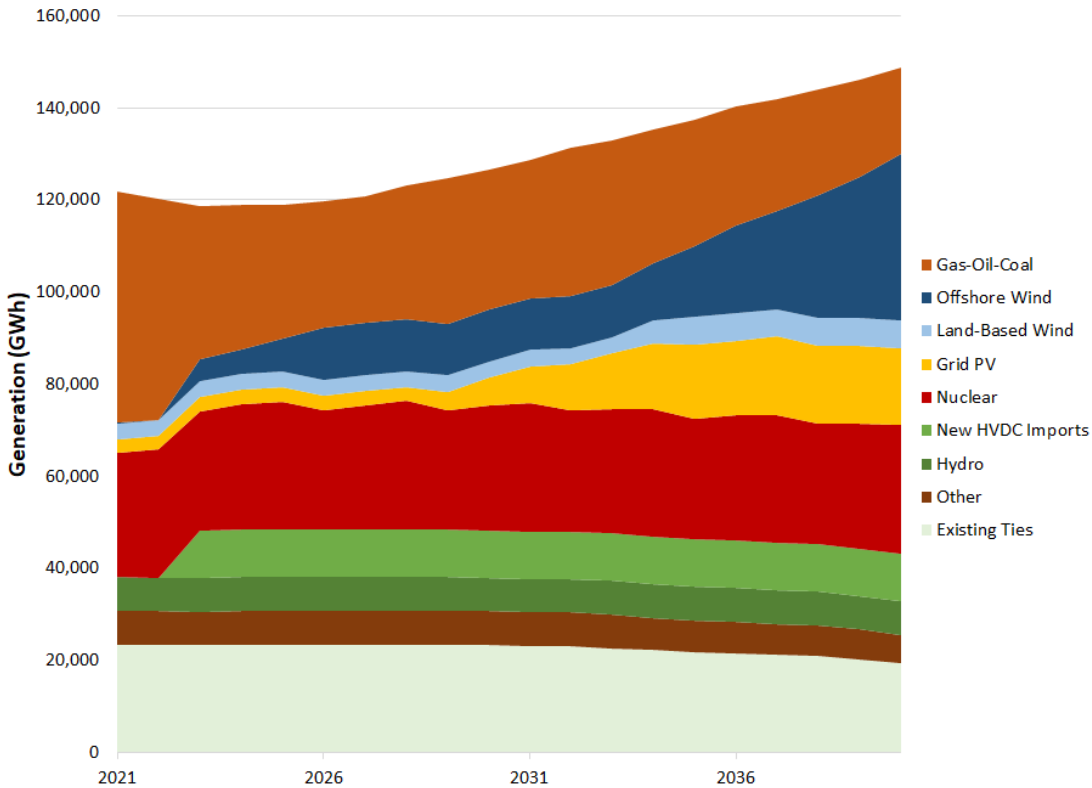


Figure 26: Annual Regional Generation, Electrification Millstone Extension Scenario



4.2 Curtailment Analysis

Curtailments are caused by weather-based generation coincidence and locational constraints. Curtailments may be mitigated by some combination of (1) identifying alternate points of interconnection, particularly for offshore wind resources, that avoid export constrained areas (2) building transmission upgrades that ease export constraints, (3) adding storage resources that smooth out VER supply and move generation to higher-demand periods, (4) moving demand to high VER supply periods, such as during midday solar peak, and (5) increasing ties and coordination with other regions to maximize geographical diversity of VERs. In the Balanced Blend cases, shown in Figure 27 and Figure 28, a significant amount of renewable generation is curtailed due to export constraints in SEMA/RI and Northern New England. Approximately 4.1 TWh of VER generation, 6.8% of grid-scale wind and solar capability, is curtailed in 2040 in the Base Balanced Blend Scenario. Likewise, 9.2 TWh of VER generation, 11.6% of grid-scale wind and solar capability, is curtailed in 2040 in the Electrification Balanced Blend Scenario. Land-based wind in Northern New England, especially Maine, has the most curtailment as a portion of nameplate capability. Grid PV is curtailed sparingly as it is more difficult to curtail and therefore maintains higher priority to avoid curtailments if overall VER generation forces resources to "spill."

Based on the levels of curtailments still experienced in the Transmission scenarios, shown in Figure 29 and Figure 30, a significant portion of curtailments are weather-based and therefore would require other mitigation strategies. Even with only some reduction in curtailments, the deferral of clean energy resource builds otherwise needed to meet Connecticut's emissions goal still reduces costs significantly relative to Balanced Blend. The magnitude and duration of transmission constraints is further explored in Section 7.

Figure 27: VER Regional Curtailments, Base Balanced Blend Scenario

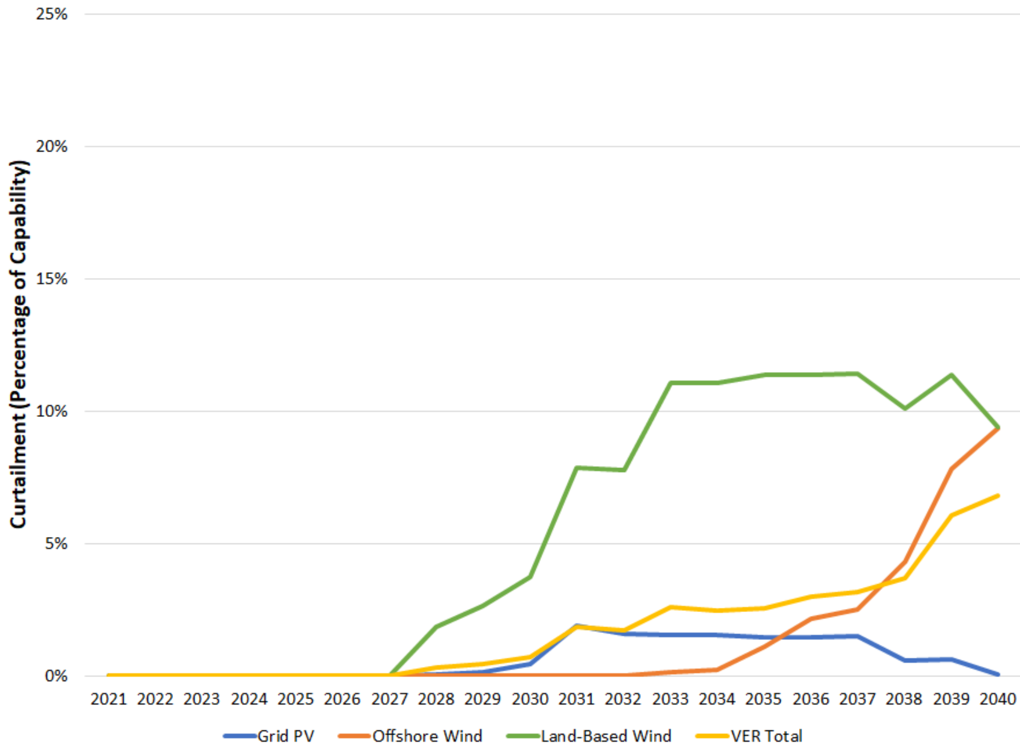


Figure 28: VER Regional Curtailments, Electrification Balanced Blend Scenario

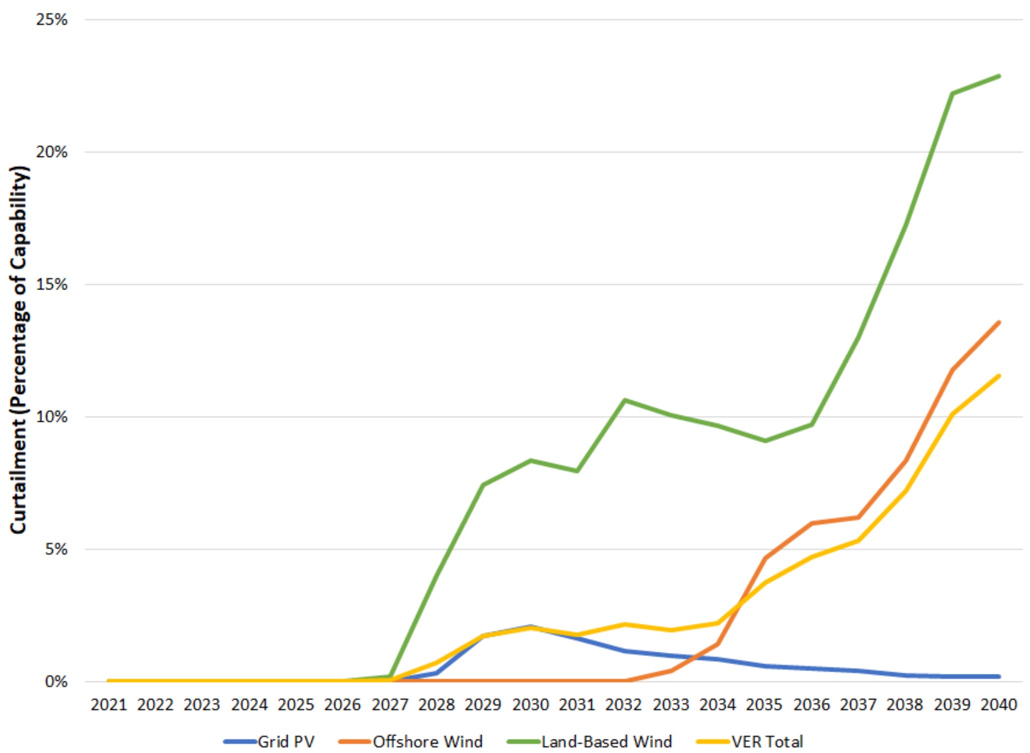


Figure 29: VER Regional Curtailments, Base Transmission Scenario

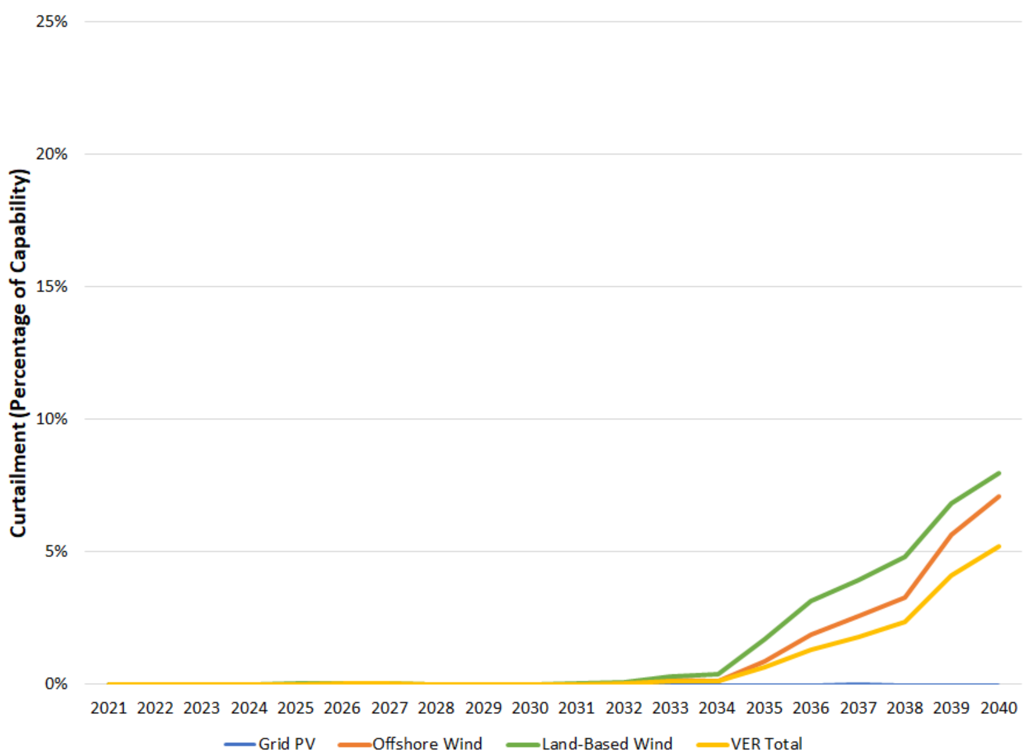
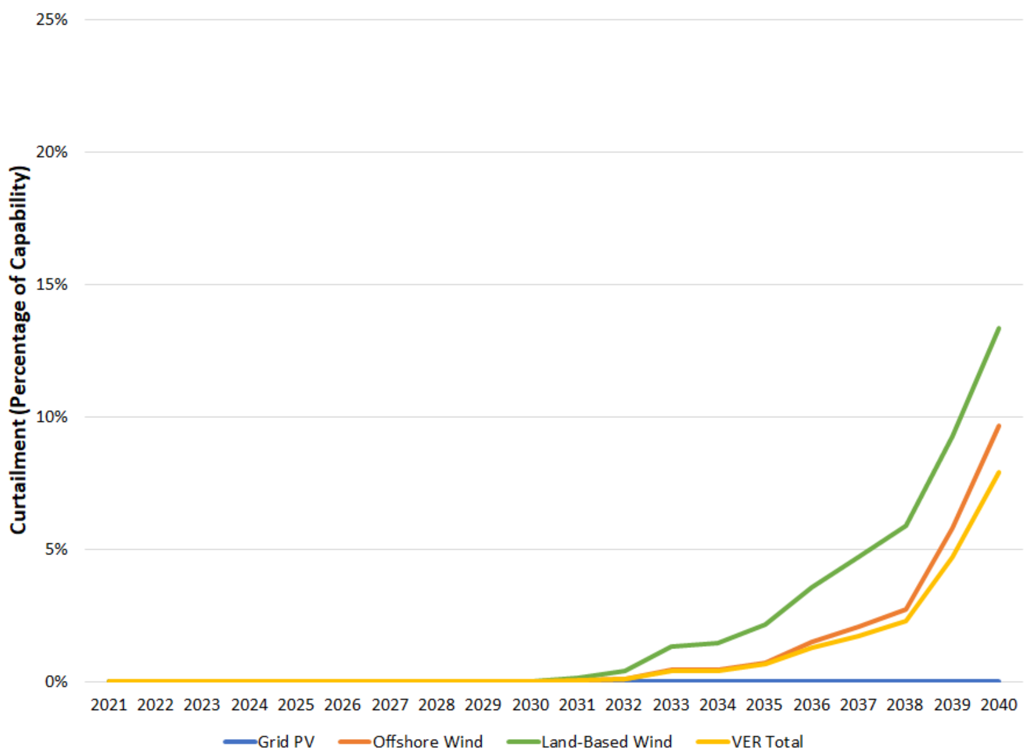


Figure 30: VER Regional Curtailments, Electrification Transmission Scenario



5 Wholesale Market Prices

Wholesale market prices for energy and capacity are affected by the differing load and resource assumptions in the various scenarios tested. It is important to recognize that wholesale prices are set by marginal resources. As most clean energy resources are effectively price takers in the Day Ahead and Real Time Markets administered by ISO-NE, clean energy additions significantly decrease wholesale energy prices. However, these resources typically require significant capital investment that cannot be formed under the "merchant" model, thereby requiring state support under long term contracts to support financing. The cost of state-sponsored procurement initiatives is reflected in retail rates through non-bypassable surcharges. The tradeoffs between wholesale market prices and retail rates to support renewable and clean energy additions are presented in the Financial Results section in the body of this report.

More detail about wholesale market price effects and other costs and benefits are presented in Section 8 of this Appendix.

5.1 Energy Prices

Prices across all Base Load scenarios remain similar through 2030 (Figure 31). The scheduled additions of NECEC and offshore wind projects cause a significant drop in prices in 2023. Over the second half of the Study Period, the Reference scenarios diverge from the other scenarios which include more clean energy resource additions. This represents a transition from high variable cost resources to high fixed cost resources. The Electrification scenarios have lower wholesale prices than the Base Load scenarios despite increased electric demand. This is explained by the reduction in gas basis relative to the Base Load scenarios due to technology substitution effects lessening gas demand on the pipeline and local gas distribution system in New England; increased ASHP penetration lowers gas demand for heating, thereby reducing basis during the heating season. The foundation for the gas pricing adjustments is addressed in Section 8.1 of Appendix 1.

Figure 31: Connecticut Energy Price Comparison, Base Scenarios

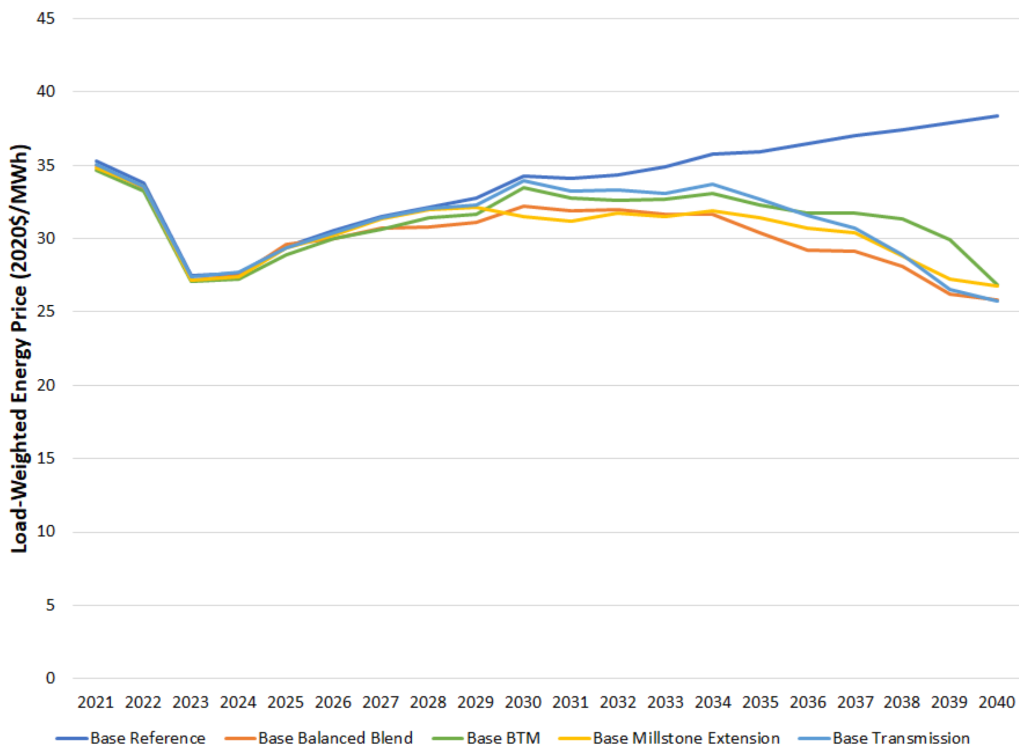


Figure 32: Connecticut Energy Price Comparison, Electrification Scenarios

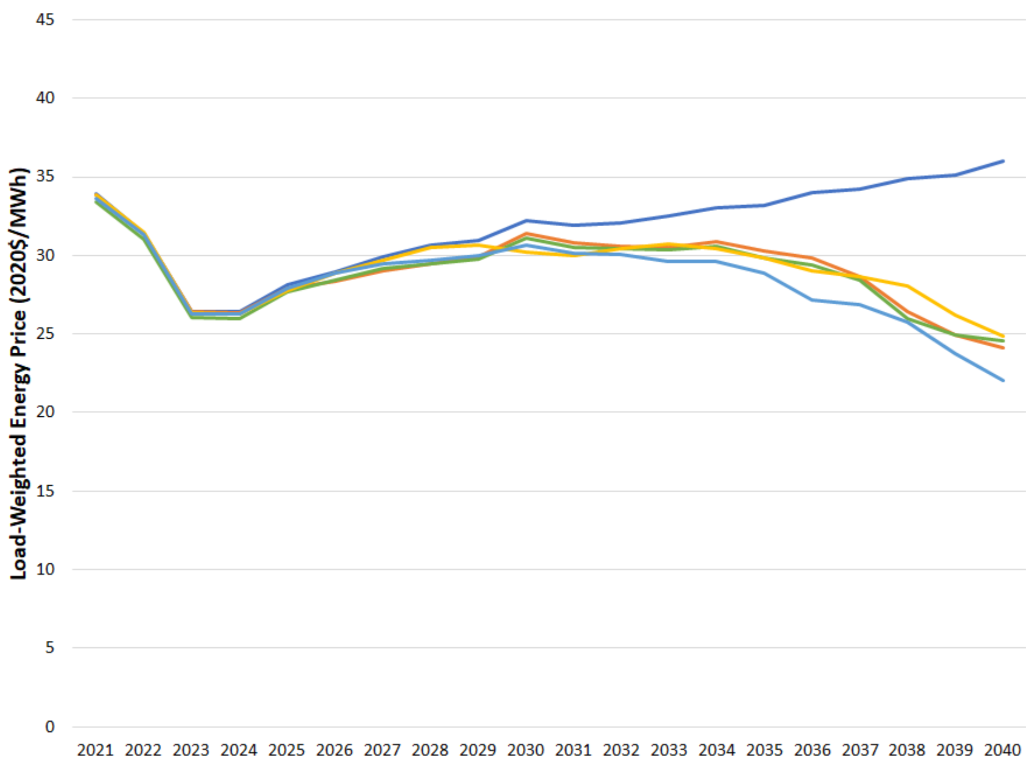
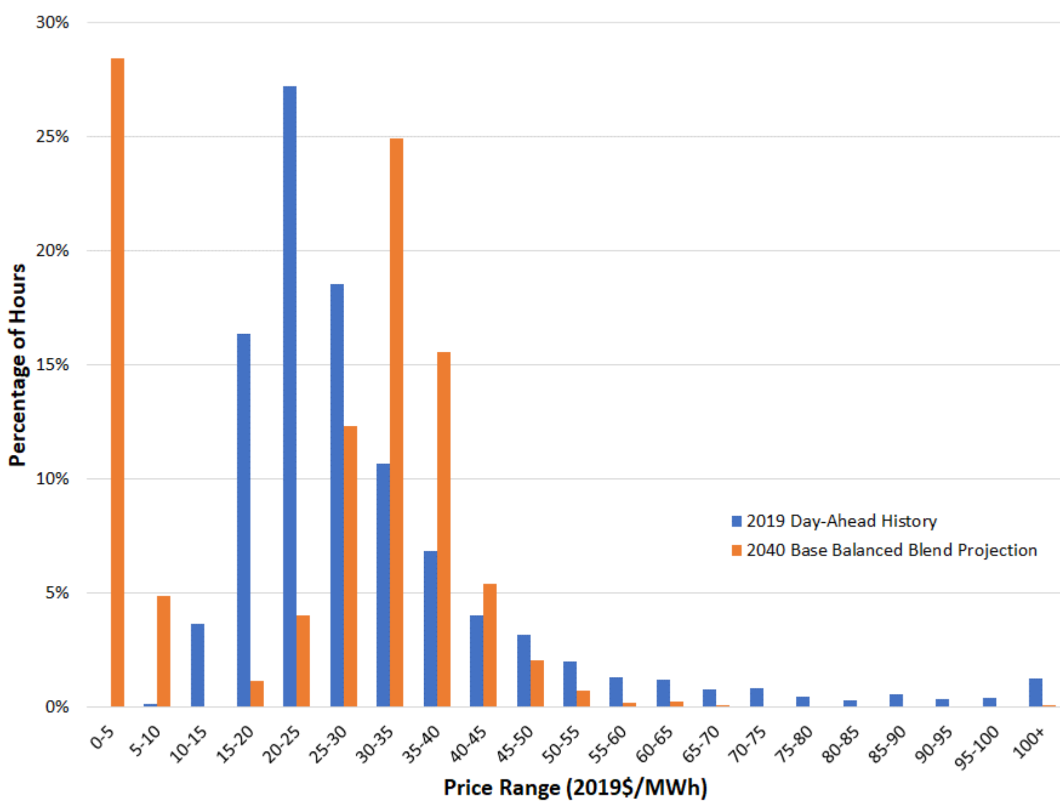


Figure 33: Distribution of Hourly Energy Price Comparison



Price formation in the energy market changes dramatically as clean energy resources replace fossil generation. Figure 33 compares the occurrence of prices in various hourly ranges in Connecticut between 2019 day-ahead history and the projections in the Base Balanced Blend scenario for 2040. While historical hourly prices have remained relatively close for most hours of a day, price variability increases with more variable and less certain generation from wind and solar PV resources. The price distribution for the Base Balanced Blend scenario in 2040 is bimodal, with the largest shares of hours in the $0 to $5/MWh bin and the $30 to $35/MWH bin. Canadian imports or renewables set energy prices as the marginal fuel in many hours in the latter years of the non-Reference scenarios. Curtailment prices in Table 13 were informed by assumptions used in ISO-NE's economic studies.[3]

Table 13: Curtailment Prices for Clean Energy Sources

Resource Type	Curtailment Price ($/MWh)
NECEC	1
Grid Solar	2
Wind	3
Hydro	4
HQ Imports	5
NB Imports	10

BTM Solar is not considered curtailable in this Study.

5.2 Capacity Prices

There is substantial uncertainty regarding various factors which influence capacity price formation over the next twenty years. Therefore a "missing money" approach was taken to project capacity prices and associated payments from load to generation. A pool-wide capacity price was calculated based on the capacity revenue needed to make a marginal resource (the least economic resource absent a capacity payment) whole in each year. The marginal resource had to be a candidate for retirement or addition.

For most of the study period, the marginal resource identified was a conventional fossil resource. In the early 2030's, batteries are needed to meet resource adequacy targets. The cost of battery additions therefore set the capacity price. The capacity price in years where batteries became the marginal capacity resource were set based on the lesser of:

1. The missing money needed to make new battery resources whole
2. An estimate of Net CONE per wholesale energy market calculations from the modeled year

[3] Haizhen Wang, ISO-NE. "ANBARIC 2019 Economic Study – Offshore Wind Results," slide 8. Presented March 18, 2020 at the Planning Advisory Committee meeting. https://www.iso-ne.com/static-assets/documents/2020/03/a8_anbaric_2019_economic_study_prelim_results_marpac.pdf

Missing money for new battery resources was calculated by comparing energy margins from the Aurora modeling to fixed costs (O&M and capital carrying charges).[4] Net CONE was estimated by projecting the three components of (Gross) CONE, Energy & Ancillary Services (E&AS) offset, and Performance Payment offset. CONE was projected forward from the established CONE for FCA15 of $11.951/kW-month based on the four most recent forward capacity market parameters' growth rate, which is slightly below the general inflation assumption of 2%.[5] E&AS and Performance Payment revenue offsets are calculated that are subtracted from CONE to determine net CONE in a similar manner as done by the Offer Review Trigger Price (ORTP) Updates from ISO-NE.[6] The E&AS offset is scaled per the average monthly on-peak market heat rate as calculated from Aurora results and increased per inflation. The Performance Payment offset is held constant at $0.67/kW-month, consistent with the latest ORTP calculation.[7] As unit going-forward costs are much lower than net CONE, the capacity price undergoes a step change when battery storage resources are needed to meet resource adequacy.

The timing of the step change in capacity prices is the main differentiator for comparing prices and reflects tight resource adequacy conditions when storage is needed. Resource adequacy is affected by several factors: clean energy resource additions, peak load, and conventional resource attrition. Aurora's capacity expansion schedule weighed these factors in an iterative estimate of resource value, subject to clean energy generation and resource adequacy constraints. Capacity expansion schedules for the Reference and Balanced Blend scenarios were used as inputs for MARS modeling to evaluate whether they met reliability standards. MARS modeling is further described in Appendix 2.

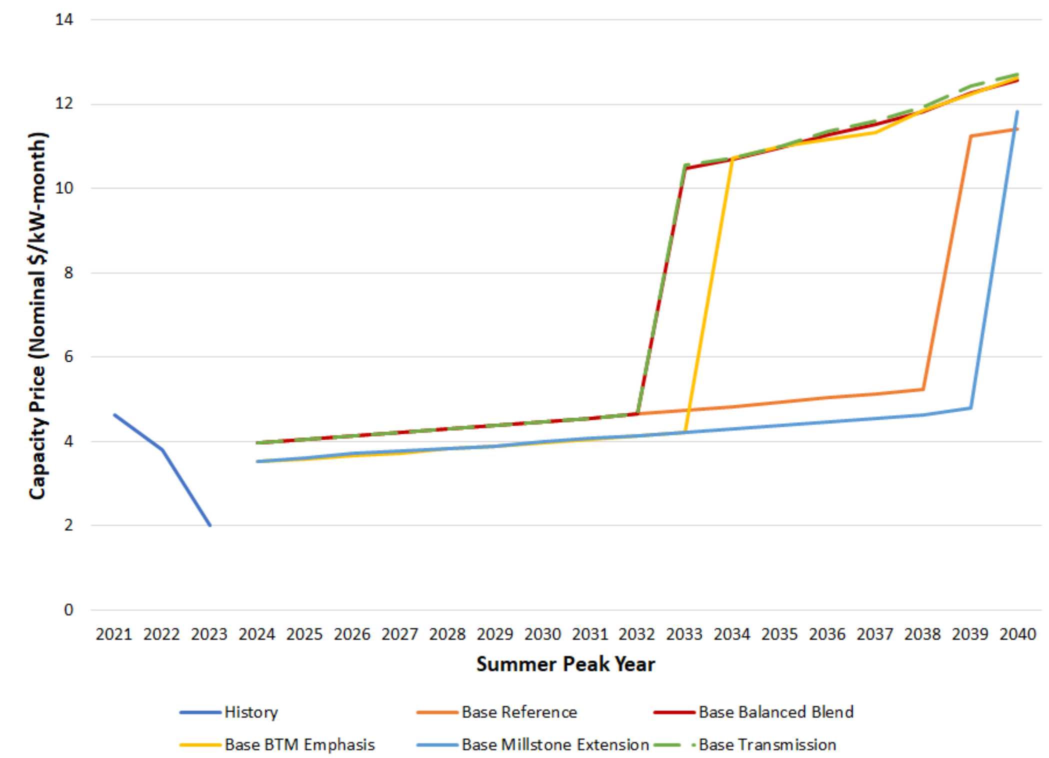
[4] See Appendix 1 for information on cost projections.

[5] https://www.iso-ne.com/static-assets/documents/2015/09/FCA_Parameters_Final_Table.xlsx

[6] https://www.iso-ne.com/static-assets/documents/2020/03/2024-2025-ccp-forward-capacity-auction-15-iso-offer-review-trigger-price-update.xlsx

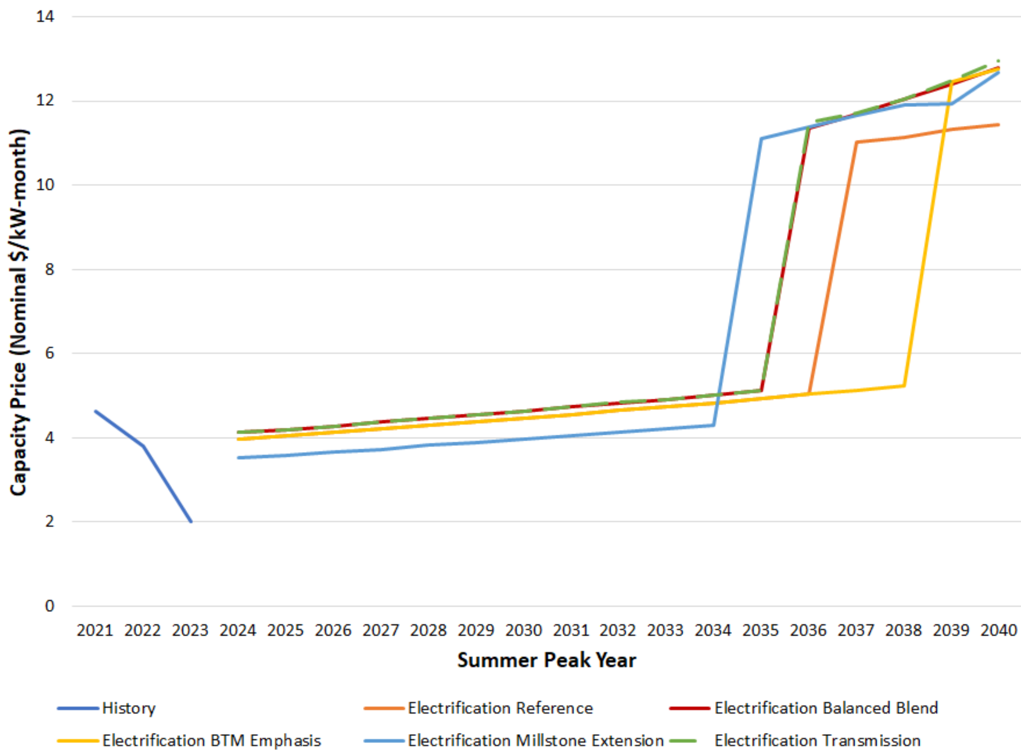
[7] By FCA15, the performance payment rate reached the maximum of $5,455/MWh and is no longer being phased in.

Figure 34: Capacity Price Comparison, Base Scenarios



In the Base scenarios, capacity price formation is set by new entry much earlier in the Balanced Blend, BTM Emphasis, and Transmission scenarios relative to the Reference and Millstone Extension scenarios. In the Electrification scenarios, the differences in step changes between various scenarios are less pronounced. Despite an elevated planning reserve margin in the second half of the Electrification scenarios per MARS modeling adjustments, step changes in prices did not consistently accelerate earlier in the study period due to reduced retirement relative to Base scenarios.

Figure 35: Capacity Price Comparison, Electrification Scenarios



In both Base and Electrification scenarios, the Reference capacity prices in the latter years of the Study Period were lower than for policy resource scenarios. This difference was due to higher market heat rates, and therefore more robust E&AS offsets, which reduced net CONE.

6 Emissions

The policy scenarios result in significant reductions to emissions in Connecticut and New England at large. Differences in emissions between the various policy scenarios, however, are fairly limited as each scenario requires similar amounts of clean energy build. CO_2 emissions region-wide are important to Connecticut's policy decisions, as Connecticut uses a consumption-based GHG emissions inventory system. In the Base policy scenarios, emissions in the latter half of the Study Period are similar (Figure 36). The BTM PV Emphasis case has lower emissions in the early years of the Study Period, as BTM additions are static inputs into the model and are not deferred to meet emissions goals in later years. About one-half of ISO-NE's CO_2 emissions occur in Connecticut in all scenarios, mostly from WTE plants. Insofar as Connecticut uses a consumption-based accounting system, these native CO_2 emissions are effectively offset by additional contracted clean energy purchases.

Figure 36: Annual ISO-NE CO_2 Emissions Comparison, Base Scenarios

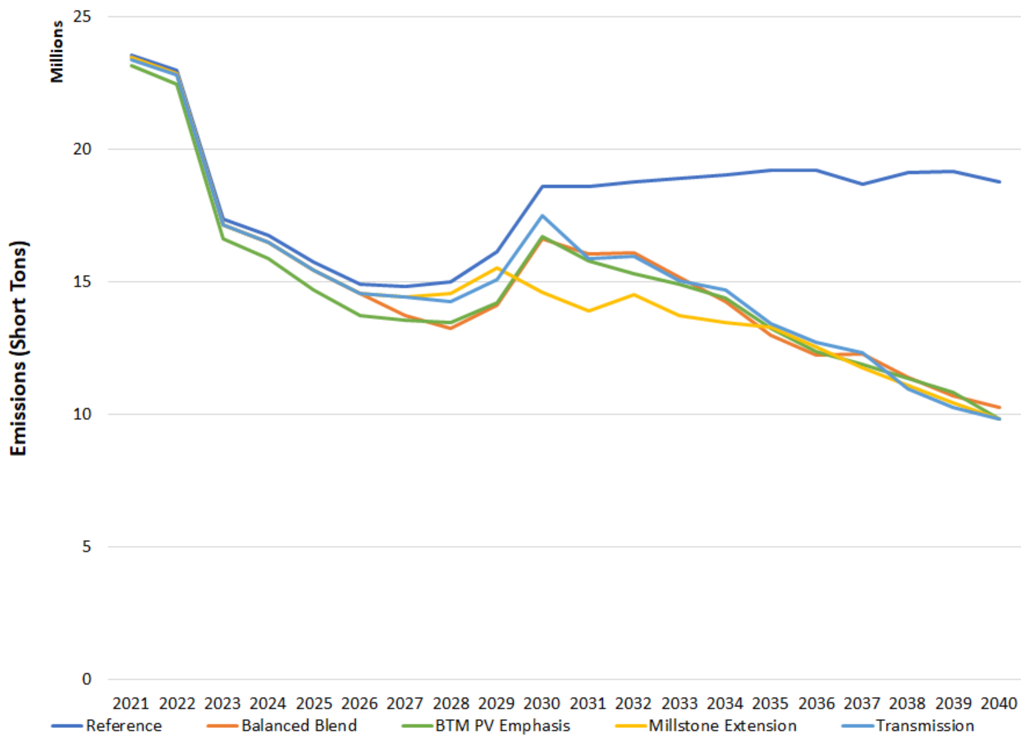


Figure 37: Annual ISO-NE CO_2 Emissions Comparison, Electrification Scenarios

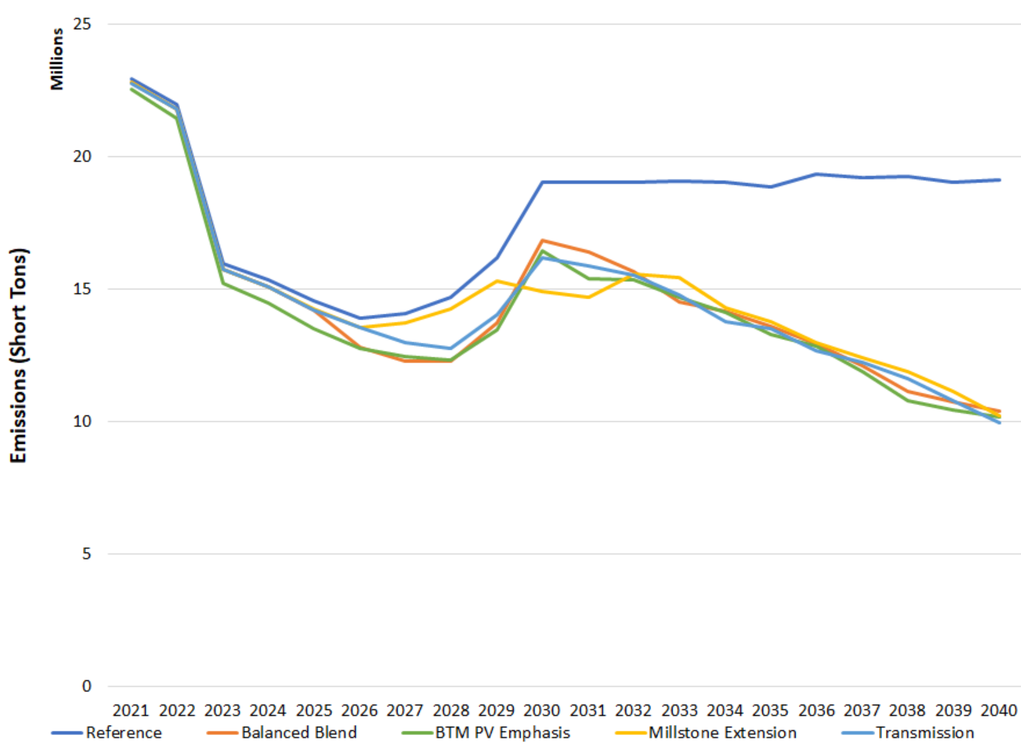


Figure 38: Annual Connecticut CO_2 Emissions Comparison, Base Scenarios

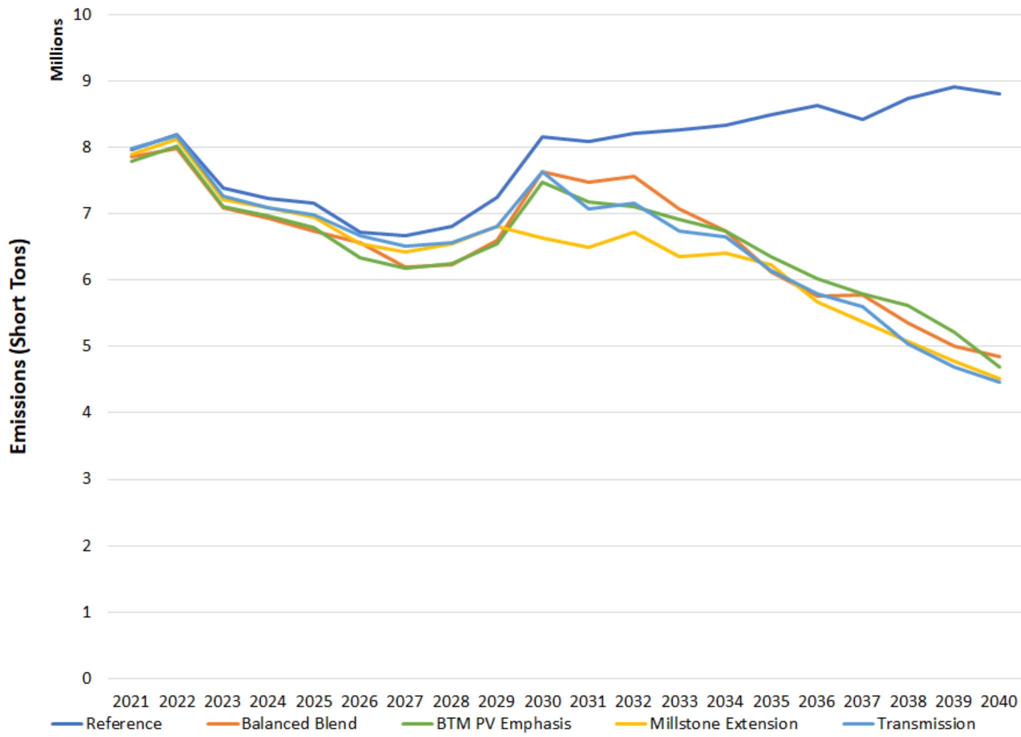
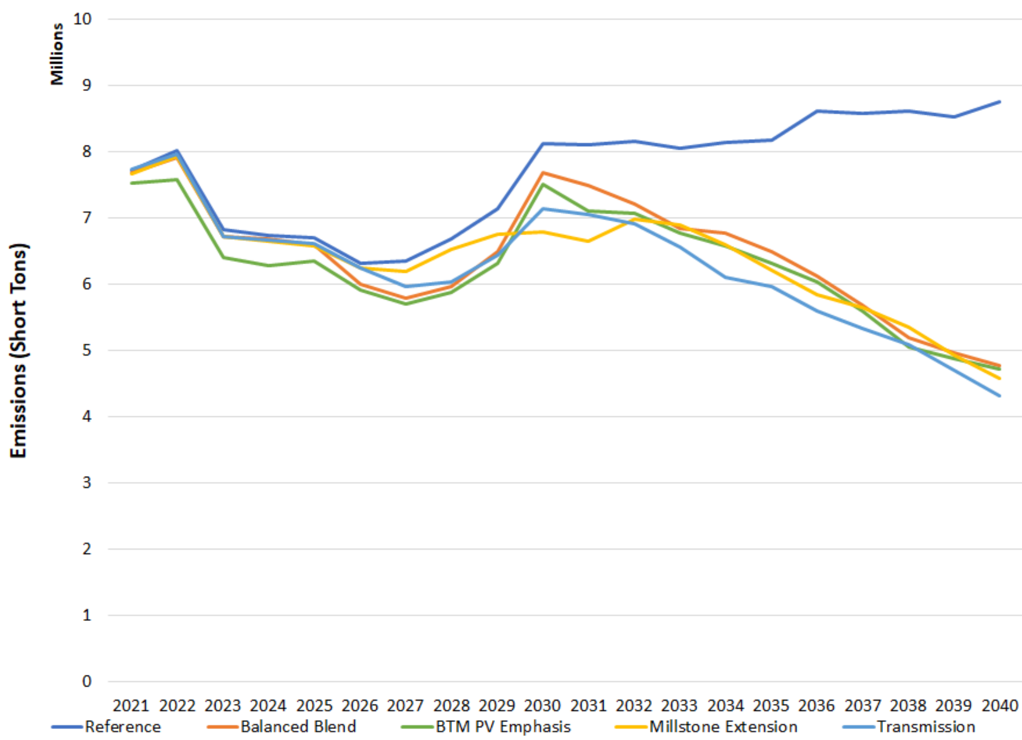
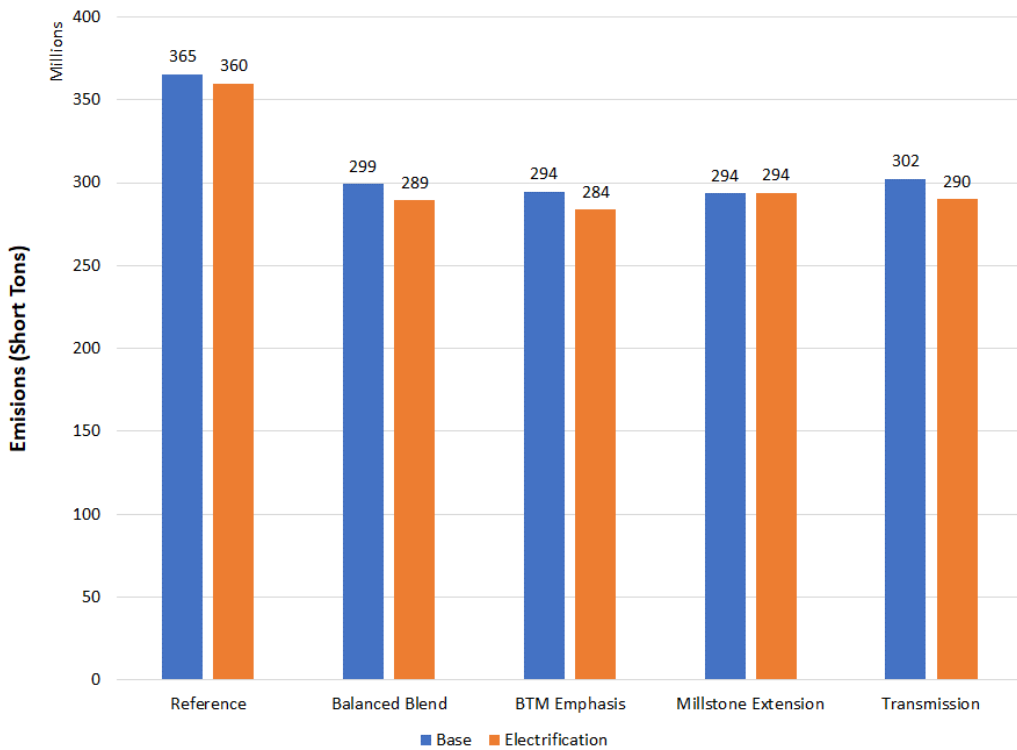


Figure 39: Annual Connecticut CO_2 Emissions Comparison, Electrification Scenarios



Cumulative CO_2 emissions were similar across policy cases as shown by Figure 40. Electrification case emissions were lower due to weatherization EE additions in the early part of the study period, which reduced CO_2 emissions prior to need for clean energy additions to meet regional emissions goals in the latter half of the study period.[8] In the Millstone Extension scenarios, some clean energy overbuild in 2032-2034 in the Base Millstone Extension scenario reduced cumulative emissions to the same amount as for the Electrification Millstone Extension scenario.

Figure 40: Cumulative Study Period ISO-NE CO_2 Emissions, All Scenario Comparison



SO_2 and NO_x are reported for Connecticut only. All the clean energy policy scenarios resulted in about a 10% reduction in SO_2 emissions by the end of the study period relative to the Reference scenarios (Table 14). By 2040, nearly all the SO_2 emitted from generation in Connecticut comes from municipal solid waste facilities, which were assumed to be must-run units and therefore are not dispatched down due to clean energy additions. The emissions decrease from 2030 to 2035 was mostly due to the retirement of the Plainfield biomass facility.[9]

[8] See Appendix A1 for details on energy efficiency assumptions used in the Base and Electrification load cases.

[9] Plainfield was retired in 2034 due to planned biomass phase-out from Tier 1 REC eligibility at the end of its PPA.

Table 14: Connecticut Annual SO_2 Emissions by Scenario
(Short Tons)

Scenario	2025	2030	2035	2040
Base Reference	1,350	1,386	1,162	1,208
Base Balanced Blend	1,348	1,367	1,115	1,069
Base BTM Solar Emphasis	1,348	1,367	1,121	1,098
Base Millstone Extension	1,349	1,374	1,120	1,079
Base Transmission	1,350	1,377	1,128	1,064
Electrification Reference	1,336	1,372	1,152	1,189
Electrification Balanced Blend	1,335	1,359	1,123	1,068
Electrification BTM Solar Emphasis	1,330	1,351	1,115	1,064
Electrification Millstone Extension	1,335	1,362	1,109	1,082
Electrification Transmission	1,334	1,358	1,106	1,057

NOx emissions in Connecticut are more sensitive to clean energy additions, as gas-fired facilities offset by clean energy additions represent a more significant portion of NOx emissions. By the end of the study period in 2040, the policy scenarios reduce NOx emissions by about 1,500 short tons annually. As with SO_2 emissions, a significant portion of Connecticut's NOx emissions cannot be displaced by clean energy resources, as they come from municipal solid waste facilities.

Figure 41: Connecticut NOx Emissions, Base Scenarios

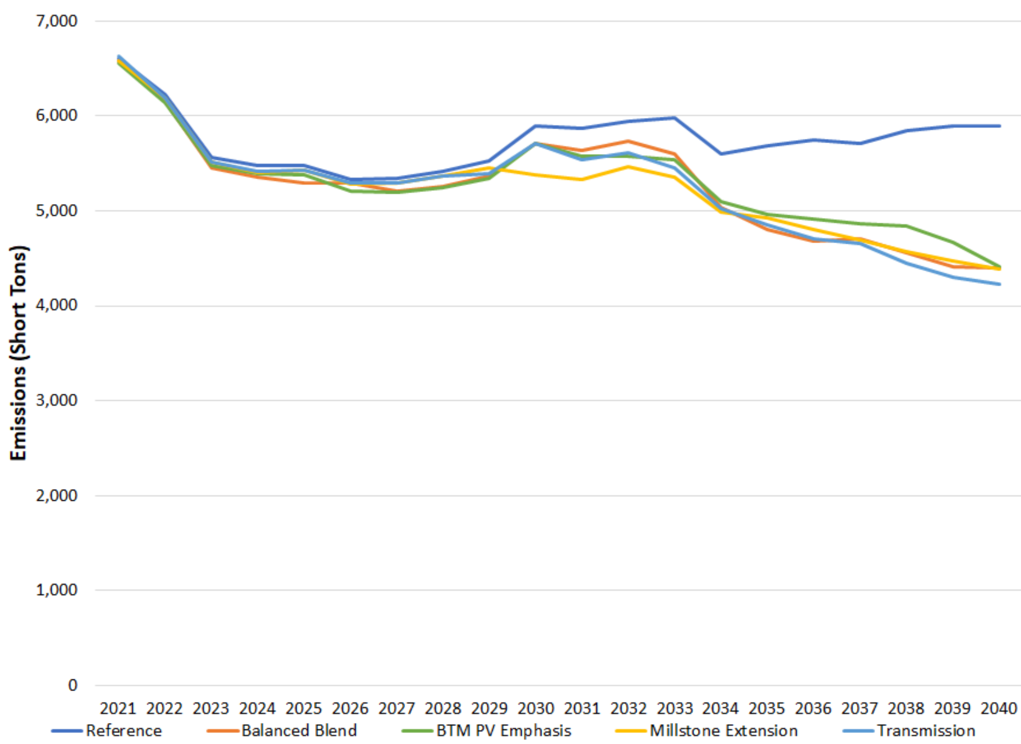
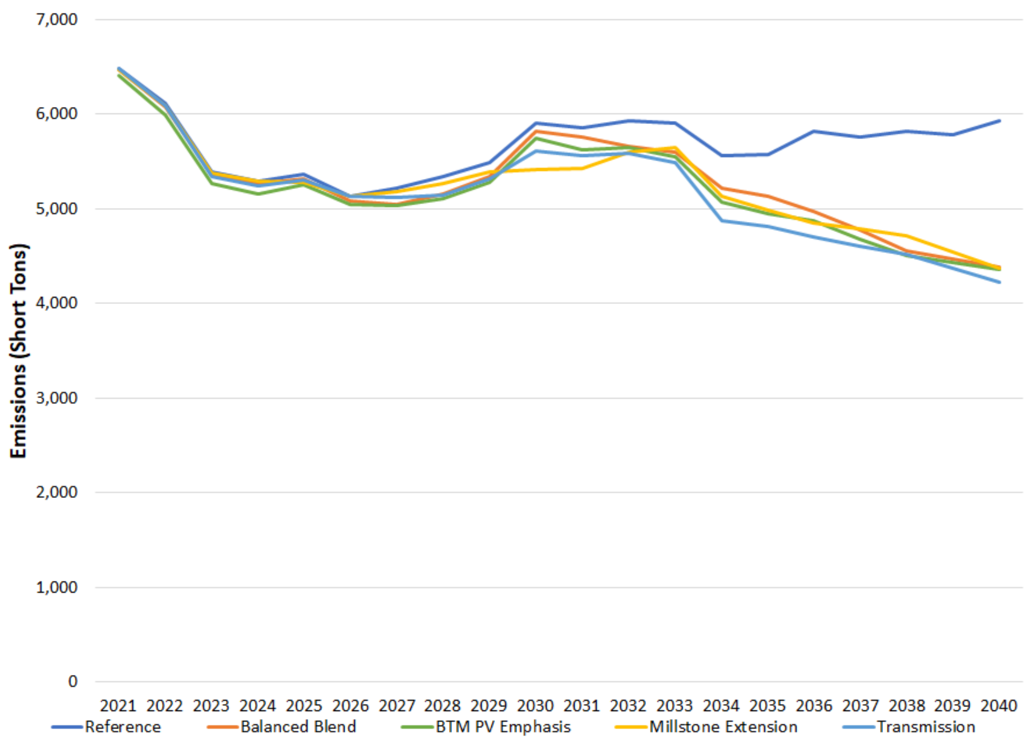


Figure 42: Connecticut NOx Emissions, Electrification Scenarios



7 Hourly Dynamics

7.1 Energy Generation and/or Load by Technology

In this section, the typical expected (mean) hourly shapes and associated variability of generation and/or load by technology are addressed. The loads and technologies are for ISO-NE at large. Due to the large amount of results data, the presentation is limited to year 2040 for the Electrification Balanced Blend scenario as an example. Three subsections present summary results for different time slices within the year to provide multiple perspectives on the dynamics of the large data set. The first subsection displays the monthly distribution of hourly energy in addition to average hourly values. The other two subsections contain line graphs of average hourly energy values by season and by day type, respectively. In each subsection, the technology-specific graphs are ordered by functional category. First is a high-level comparison of clean and fossil-fuel technologies. Next, the VER technologies of LBW, OSW, and UPV are presented. Finally, dispatchable storage and import technologies are shown.

7.1.1 Hourly Energy Distribution Profiles by Technology and Month

The charts in this section provide descriptive statistics that summarize the range and distribution of energy generation (after curtailment) or load around the central mean value for each technology type by month of 2040 in the Electrification Balanced Blend scenario. The number of observations summarized by each month's plot is the number of days in that month in 2040 times 24 hours. The distribution information is portrayed with box-and-whiskers plots consisting of a central box spanning the second and third quartiles (the interquartile range or IQR, from P25 to P75), with a line at the median (P50) and whiskers extending down to the fifth percentile (P5) and up to the ninety-fifth percentile (P95). In addition, the average (mean) is shown as a red dot.

Two differences between the LBW and OSW hourly generation distribution monthly plots are that OSW has, on average, more stable generation than LBW across the year. OSW also has a wider distribution of output, as indicated by both the IQR box and the length of the P90 confidence interval whiskers.

Figure 43: Land-Based Wind Hourly Generation by Month of 2040, Electrification Balanced Blend Scenario

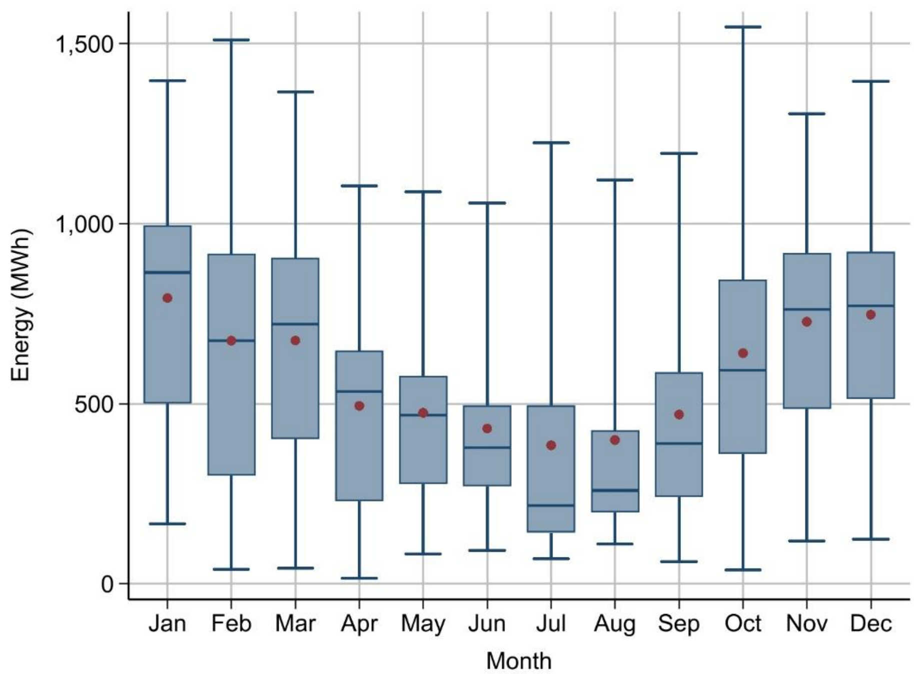
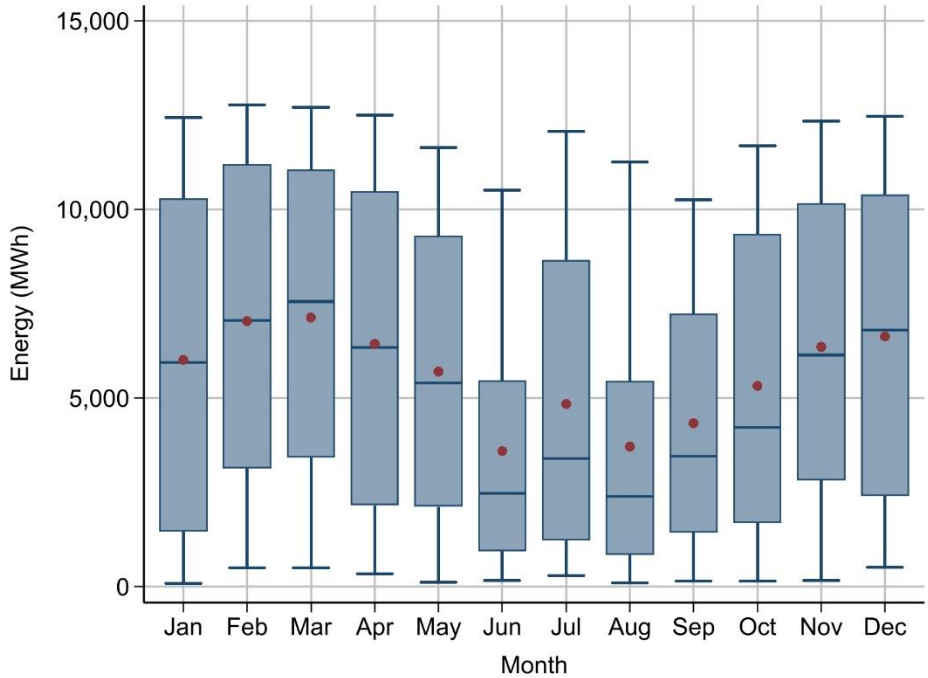
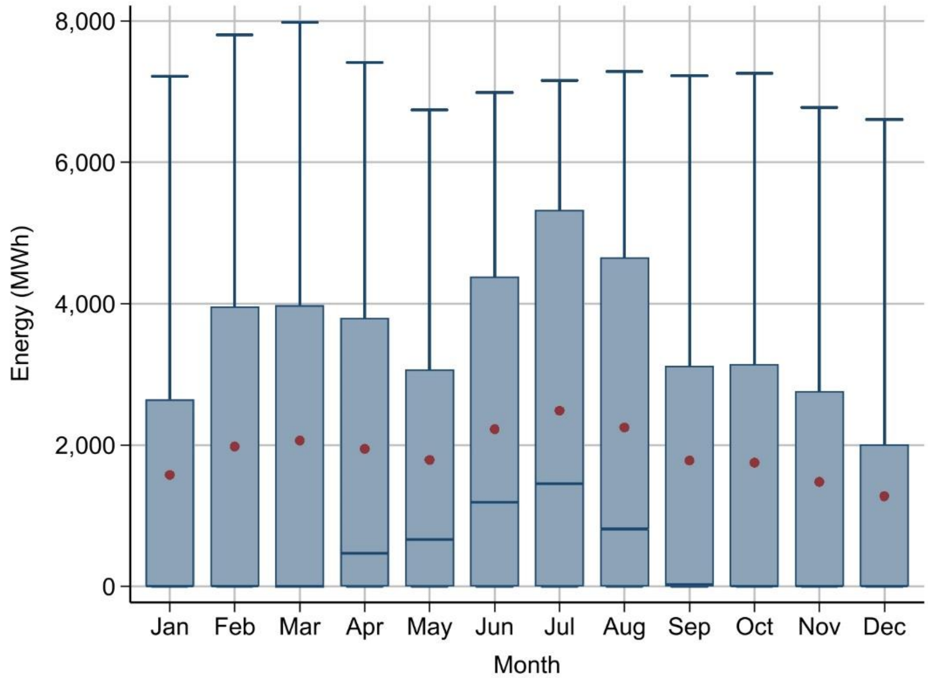


Figure 44: Offshore Wind Hourly Generation by Month of 2040, Electrification Balanced Blend Scenario



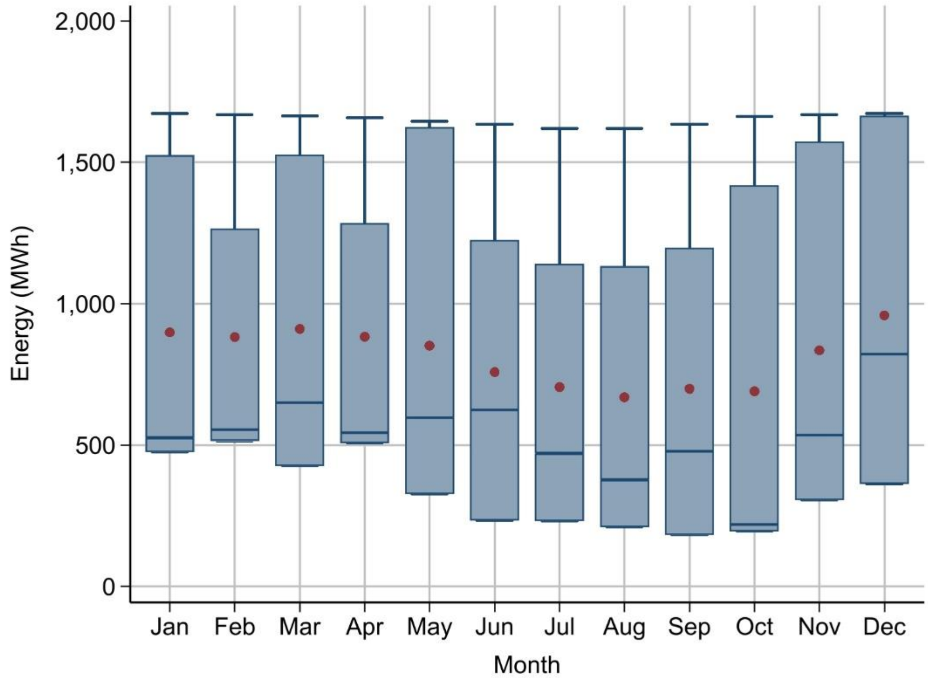
Utility PV generation is somewhat higher, on average, in summer months than in winter months. This is due the longer amount of daylight and increase in solar radiation received during the summer. Over one-half of all hours from September through March have no generation, shown by the absence of a lower than median box. Due to longer daylight times, April through August have more than one-half of hours with PV generation, indicated by the lower than median box.

Figure 45: Utility PV Hourly Generation by Month of 2040, Electrification Balanced Blend Scenario



Hydro generation is a "swing" or partly storable resource, between minimum flow constraints and maximum capability, limited by available run-of-river flow. These fundamentals are apparent in the box-and-whiskers plots, which show a smaller second quartile box than the third quartile, and no lower whiskers, while the upper whisker tips are nearly the same every month.

Figure 46: Hydro Hourly Generation by Month of 2040, Electrification Balanced Blend Scenario



By 2040, the existing ties with surrounding control areas (New York, Québec, New Brunswick) have a more pronounced seasonal pattern than presently due to import curtailments to accommodate VER generation (imports are more attractive options for curtailment per Table 13) that mainly occur in the winter and shoulder seasons. The new HVDC ties with Québec have a similar seasonal pattern of imports, but much narrower distribution of hourly imports except for February through April.

Figure 47: Existing Ties Hourly Imports by Month of 2040, Electrification Balanced Blend Scenario

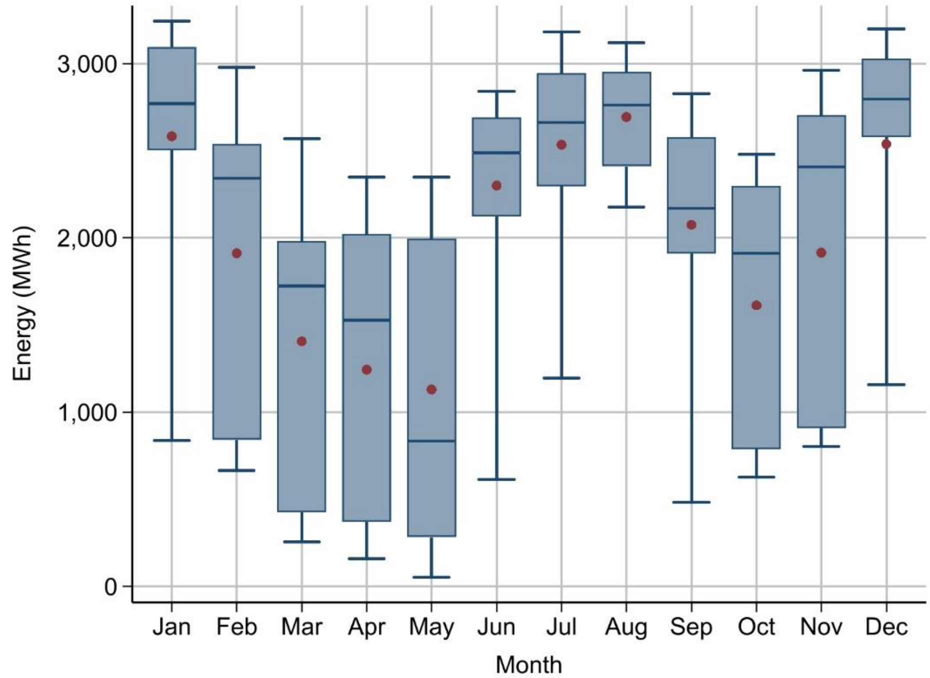
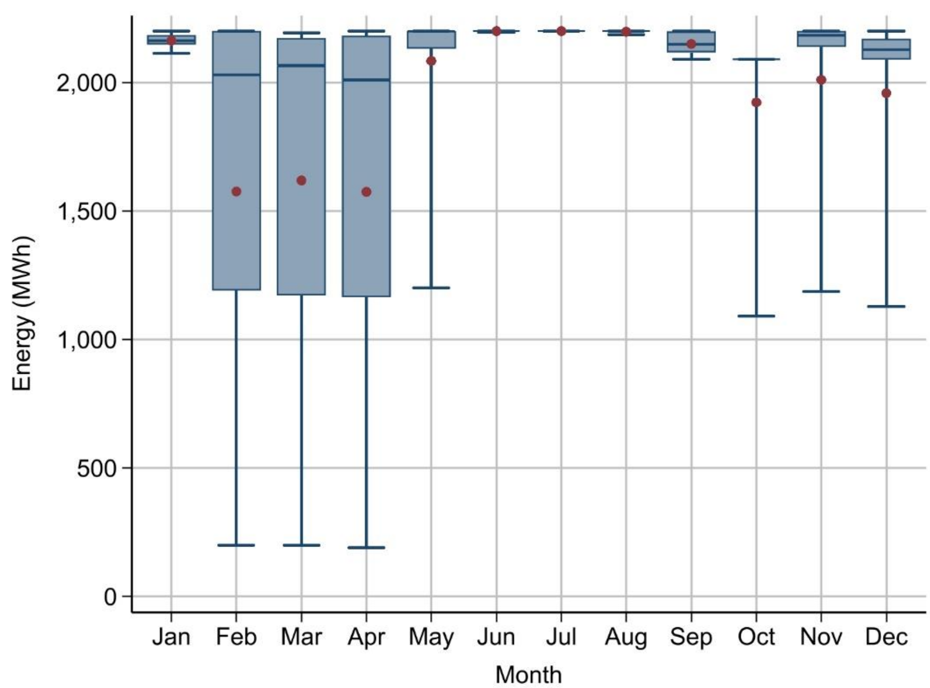


Figure 48: New HVDC Hourly Net Imports by Month of 2040, Electrification Balanced Blend Scenario



Pumped hydro storage and battery storage are both dispatched year-round and have similar monthly profiles of negative net generation due to storage cycle losses. However, pumped storage has such a narrow IQR from June through September that the boxes are not visible apart from the median lines. In contrast, battery storage has substantial IQR boxes every month because it is dispatched for shorter durations and more frequently than pumped storage.

Figure 49: Pumped Storage Hourly Generation by Month of 2040, Electrification Balanced Blend Scenario

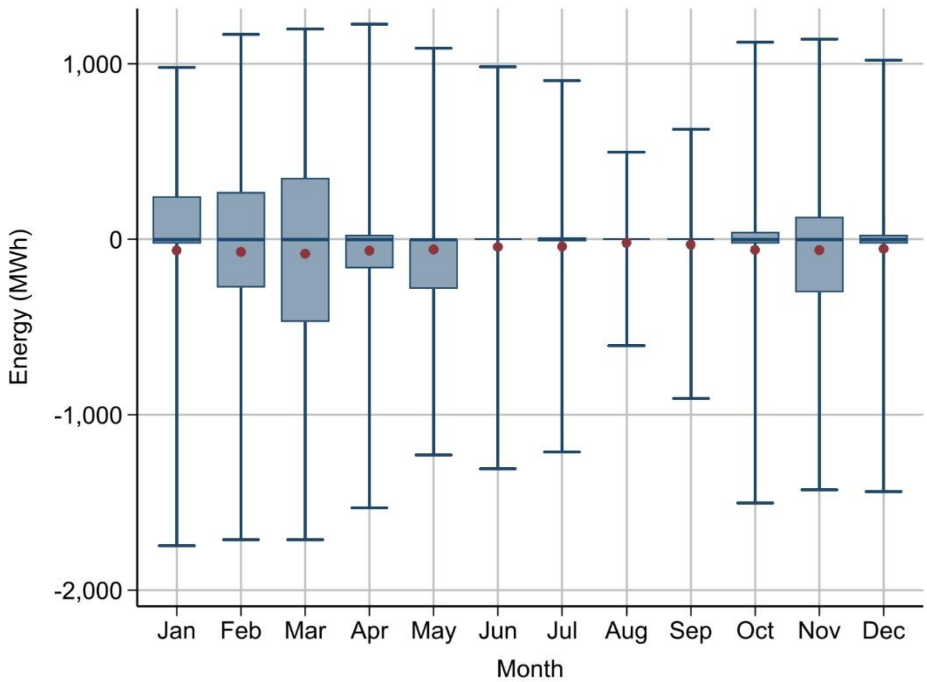
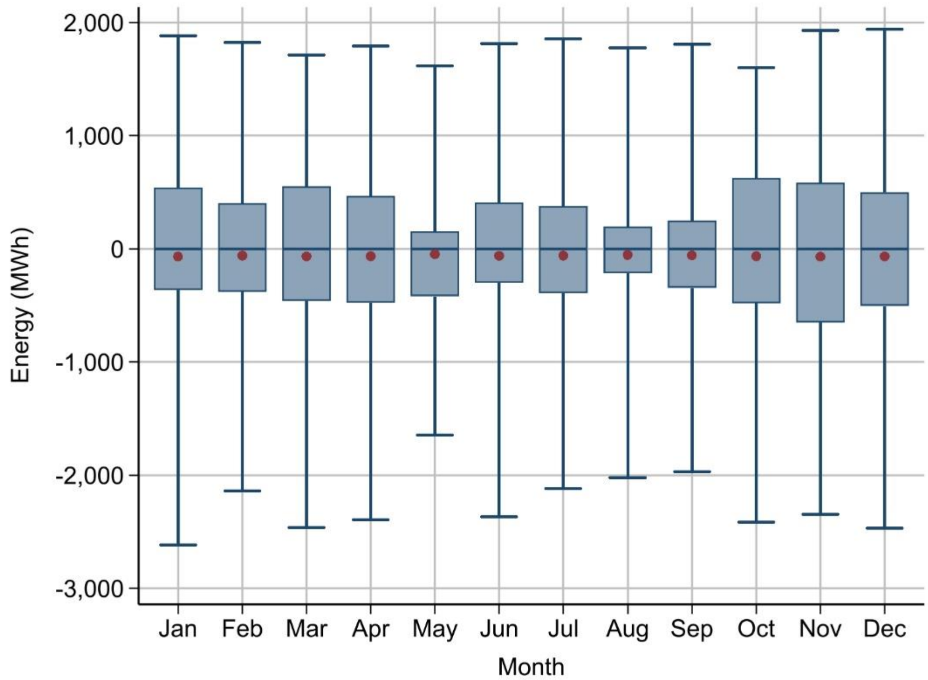
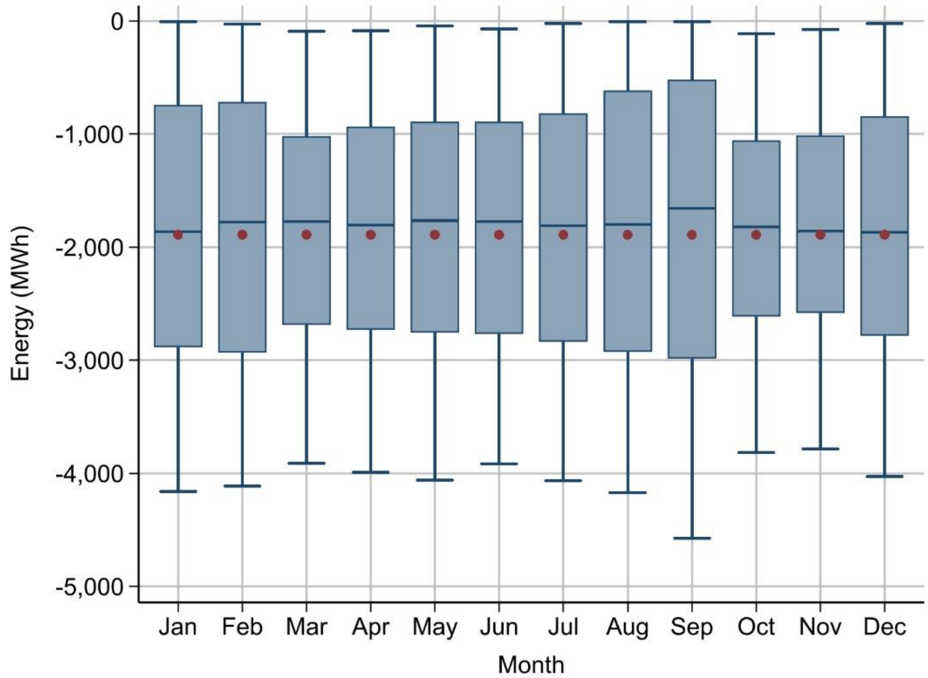


Figure 50: Battery Hourly Generation by Month of 2040, Electrification Balanced Blend Scenario



EV charging load is relatively constant across all months in 2040. The four types of EVs (battery, plug-in hybrid, medium-duty and heavy-duty) are shown in aggregate because there is little difference in their seasonal patterns. As a result of daily charging behavior patterns and Aurora's optimization of when to charge BEVs for system load management, the IQR values are substantial in all months.

Figure 51: EV Hourly Charging in 2040 by Month, Electrification Balanced Blend Scenario



7.1.2 Average Energy Profiles by Technology, Season, and Hour of Day

The charts in this section report the average energy generated (after curtailment) or consumed by each technology type, by season and hour of day in 2040 in the Electrification Balanced Blend scenario. The cooling season, May through September, is shown as the blue line and markers. The heating season, October through April, is shown as the red line and markers. The number of hourly observations averaged by each marker is 153 for the cooling season and 213 for the heating season. While quarterly seasons or monthly charts would show more detail of the annual patterns, the cooling and heating season summary charts shown here capture the main differences over a year.

By coincidence, in 2040 for the Electrification Balanced Blend scenario, the average daily peak hourly clean energy generation is nearly identical between the cooling and heating seasons in HE 17. However, the daily pattern is much flatter in the heating season than the cooling season. In contrast, the daily shapes of fossil fuel generation are very similar between seasons, with mid-day lows due to high PV generation between HE 9 and HE 16, but average hourly fossil fuel generation is somewhat higher during the cooling season to meet its higher net load.

The general shapes of LBW and OSW generation are similar between seasons and between technologies. Both wind technologies have lowest average generation mid-day. OSW has a smaller range in hourly average generation across the day than LBW, but as shown earlier, OSW has more output variability.

Figure 52: Land-Based Wind Average Generation by Season and Hour of Day in 2040, Electrification Balanced Blend Scenario

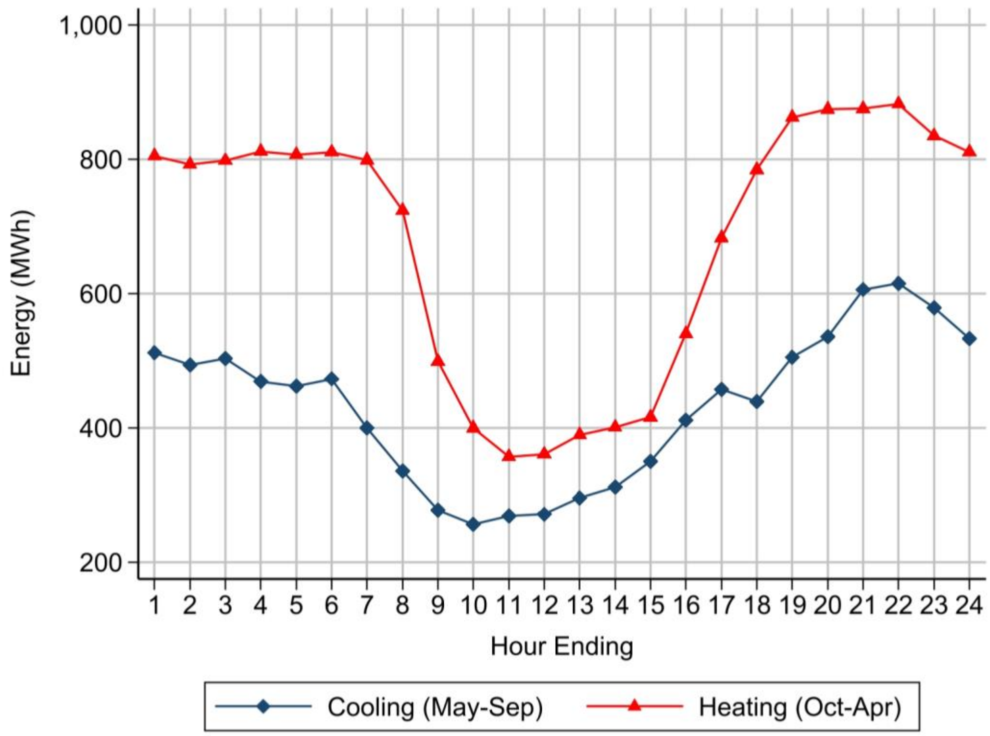
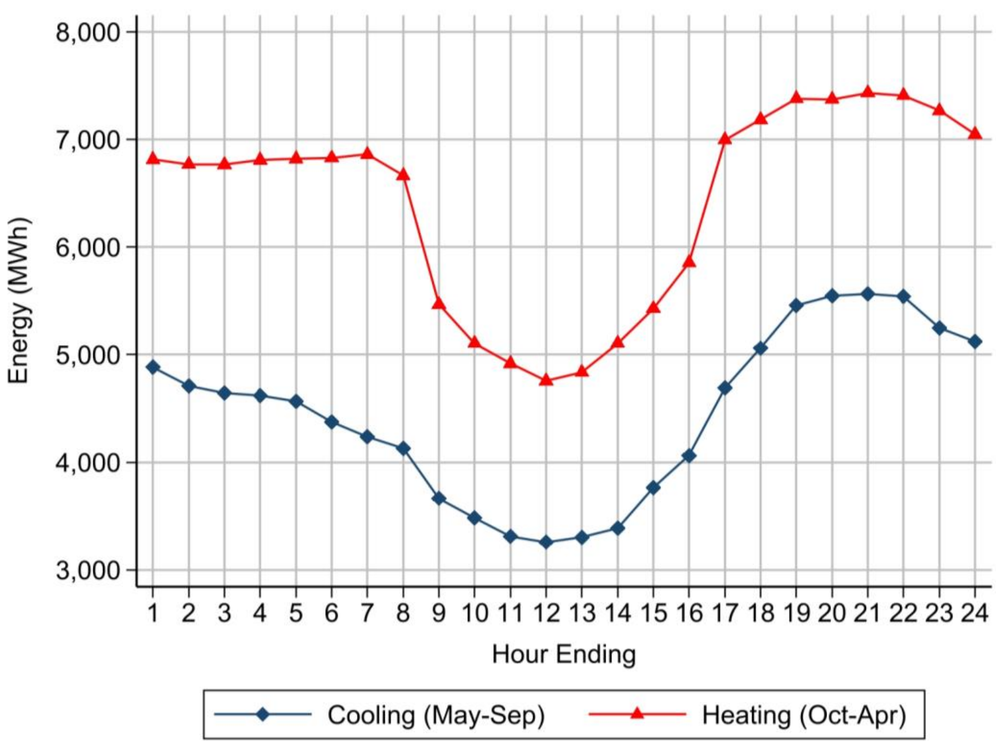
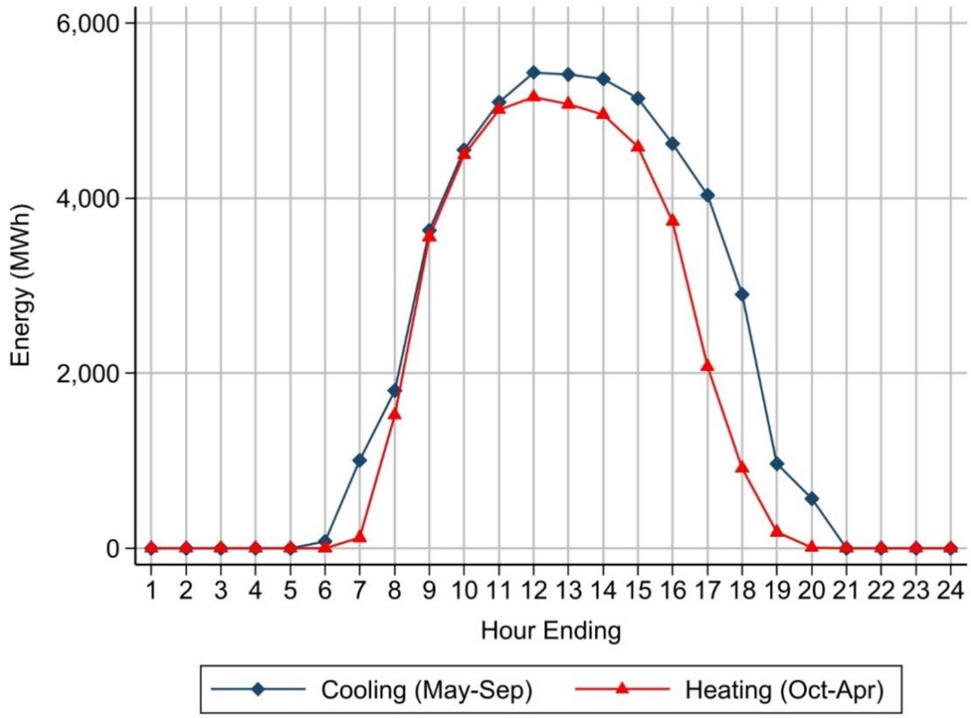


Figure 53: Offshore Wind Average Generation by Season and Hour of Day in 2040, Electrification Balanced Blend Scenario



Utility PV average hourly generation peaks at HE 12, which complements the daily trough in wind average hourly generation. PV output spans more hours during the cooling season than the winter season because of the difference in daylight duration. BTM PV generation profiles, not shown, have slightly narrower daily profiles each season compared to utility PV due to exclusive use of non-tracking arrays.

Figure 54: Utility Photovoltaic Average Generation by Season and Hour of Day in 2040, Electrification Balanced Blend Scenario



Hydro, pumped storage, and battery storage technologies all have similar daily shapes each season, with a mid-day trough and slightly higher evening generation than during the early hours. The similar patterns are the result of all three technologies having dispatchable energy storage capability.

Figure 55: Hydro Average Generation by Season and Hour of Day in 2040, Electrification Balanced Blend Scenario

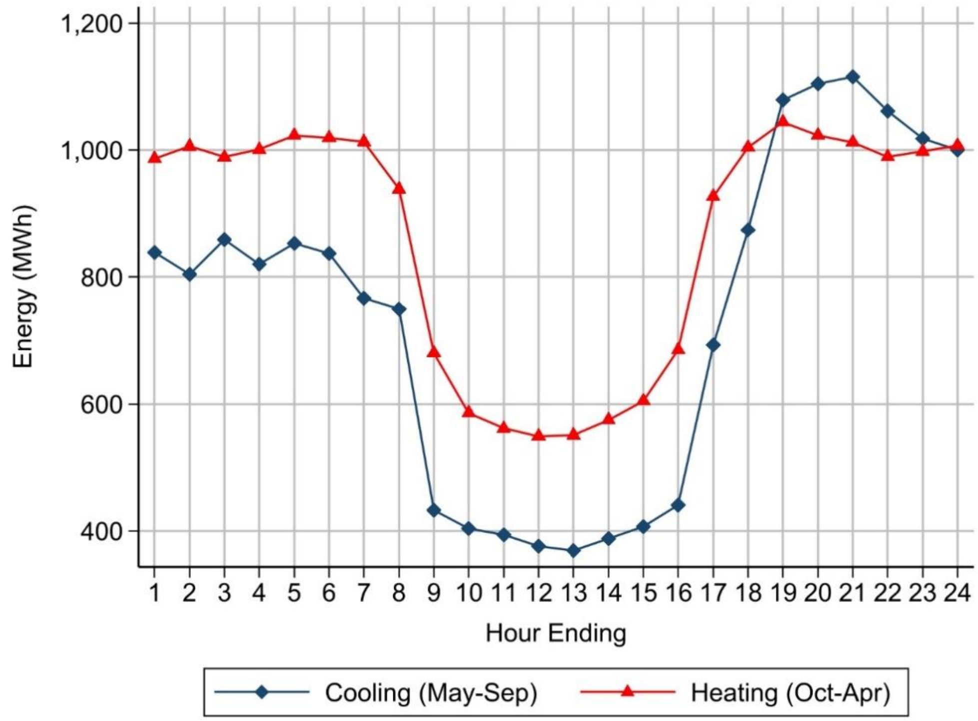


Figure 56: Pumped Storage Average Generation by Season and Hour of Day in 2040, Electrification Balanced Blend Scenario

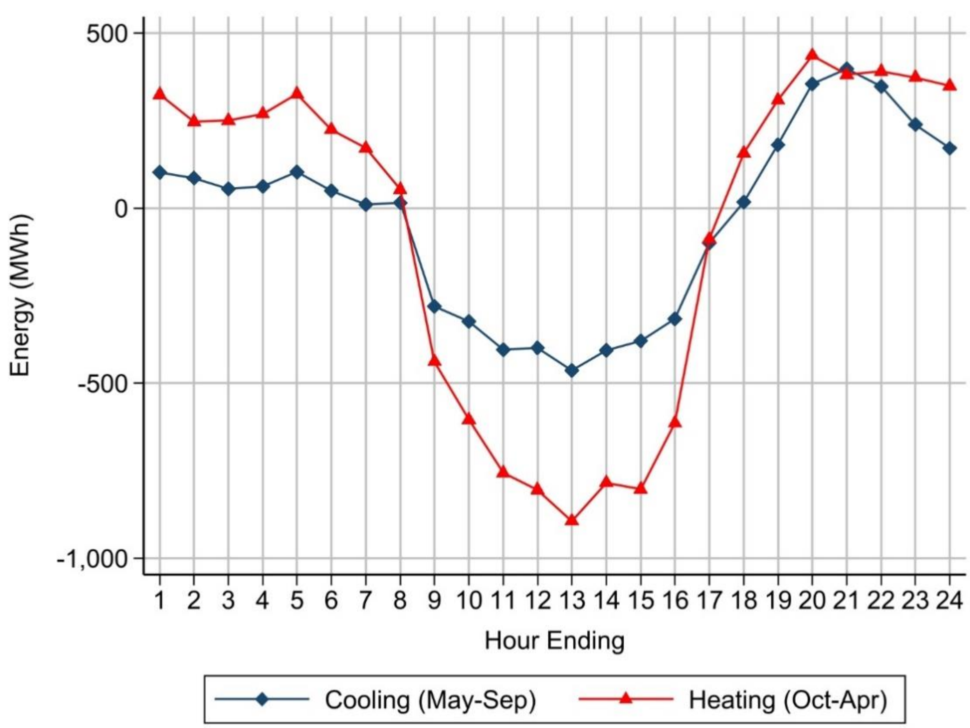
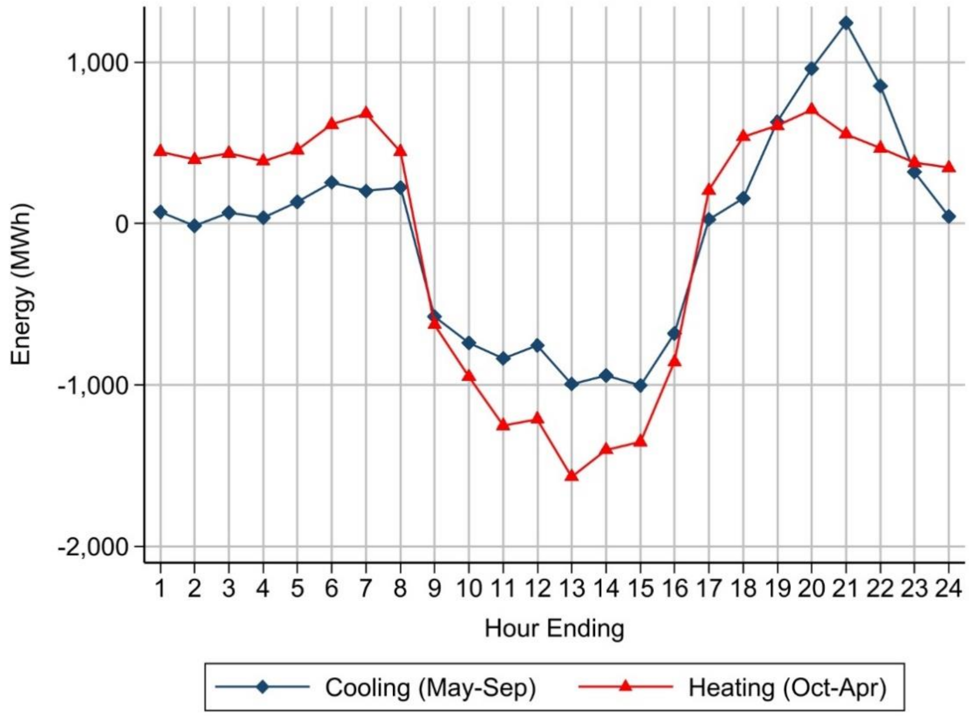


Figure 57: Battery Average Generation by Season and Hour of Day in 2040, Electrification Balanced Blend Scenario



Imports of energy from existing external ties have the same diurnal pattern each season, with midday trough, as for the storage resources. However, for new HVDC ties while the heating season also has a midday trough, there is no dip in average hourly imports during the cooling season. This dynamic is in part due to NECEC's position in curtailment order (after renewable generation and other imports, and in part due to the generic HQ tie's point of interconnection in southern New England which is not subject to transmission constraints during the summer.

Figure 58: Existing Ties Average Imports by Season and Hour of Day in 2040, Electrification Balanced Blend Scenario

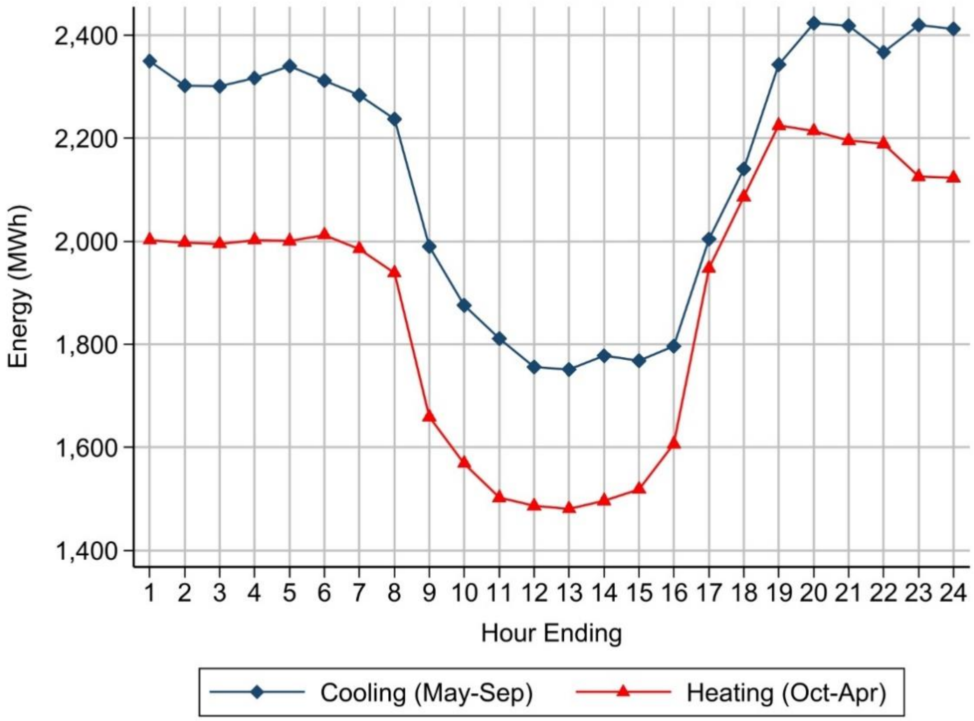
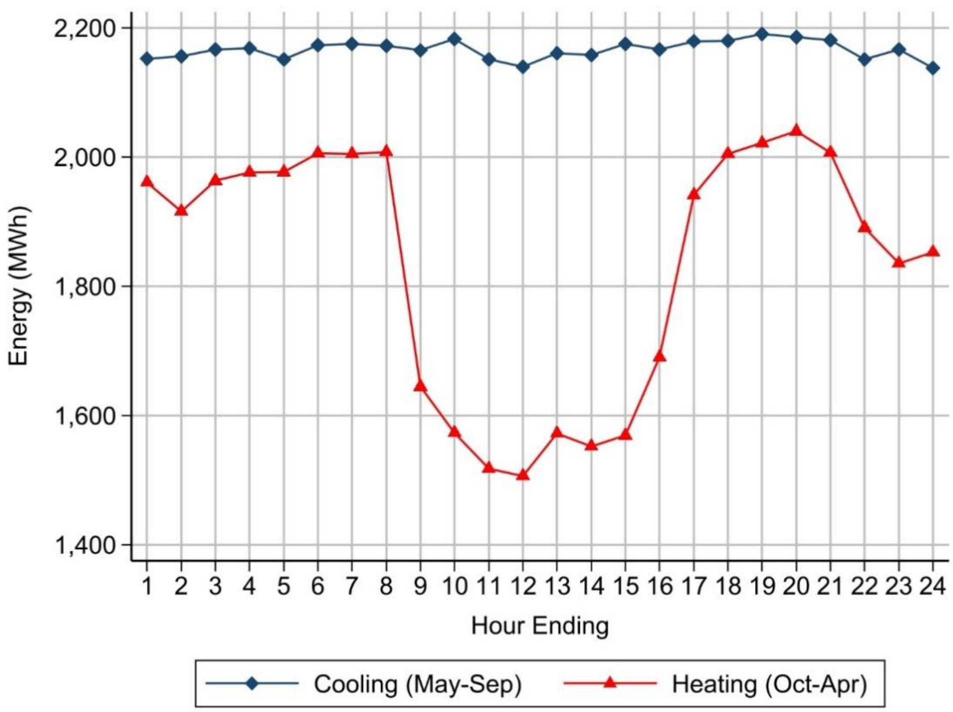
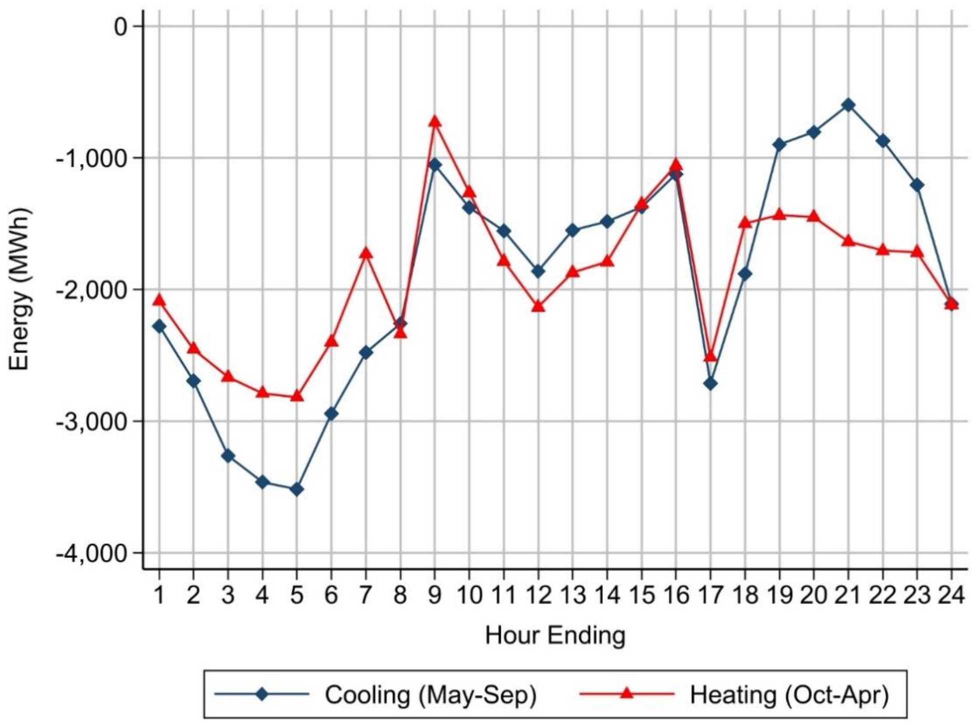


Figure 59: New HVDC Average Imports by Season and Hour of Day in 2040, Electrification Balanced Blend Scenario



The EV average hourly charging profiles are similar between seasons, but maximum charging is greater in early hours and less during evening hours in the cooling season. Partial dispatchability of charging load explains much of the difference in season patterns.

Figure 60: EV Average Hourly Charging by Season and Hour of Day in 2040, Electrification Balanced Blend Scenario



7.2 Transmission Flows

Transmission constraints in the Transmission cases were relaxed to identify the effects of the transmission constraints on the clean energy build and timing of additions. Candidate resources were restricted to those added in the Balanced Blend scenario with the same load case applied. This restriction ensured that the resource buildout and prevailing transmission flows behave similarly to the Balanced Blend scenarios and could therefore be compared. Sections 7.2.1 and 7.2.2 show how flows in 2040 on various interfaces operated compared to the current interface limits.[10] Graphs in the following two subsections show 2040 hourly flows on interfaces sorted from highest to lowest.

7.2.1 Base Load Case Transmission Scenario

Flows for all hours in 2040 for the Base Transmission scenario were examined to determine which interfaces would observe flows above the line limits absent constraints.

[10] Only 2040 is presented as it represents the final year of the study period and therefore contains the full clean resource balance.

Figure 61 shows the hourly 2040 southern Maine to New Hampshire flows from the Base Transmission scenario in green compared to the limit in grey also noted with a black line. In the all other Base case scenarios, the hourly flow limit on this interface is 1,900 MW. Relaxing the constraint resulted in 3078 hours in which the flow on the interface exceeded the known 1,900 MW limit. Increasing the limit on the interface by 1,000 MW would reduce the number of times the limit would have been exceeded to just 13% of occurences.

Figure 61: Southern Maine to New Hampshire Interface Flows, 2040 All Hours

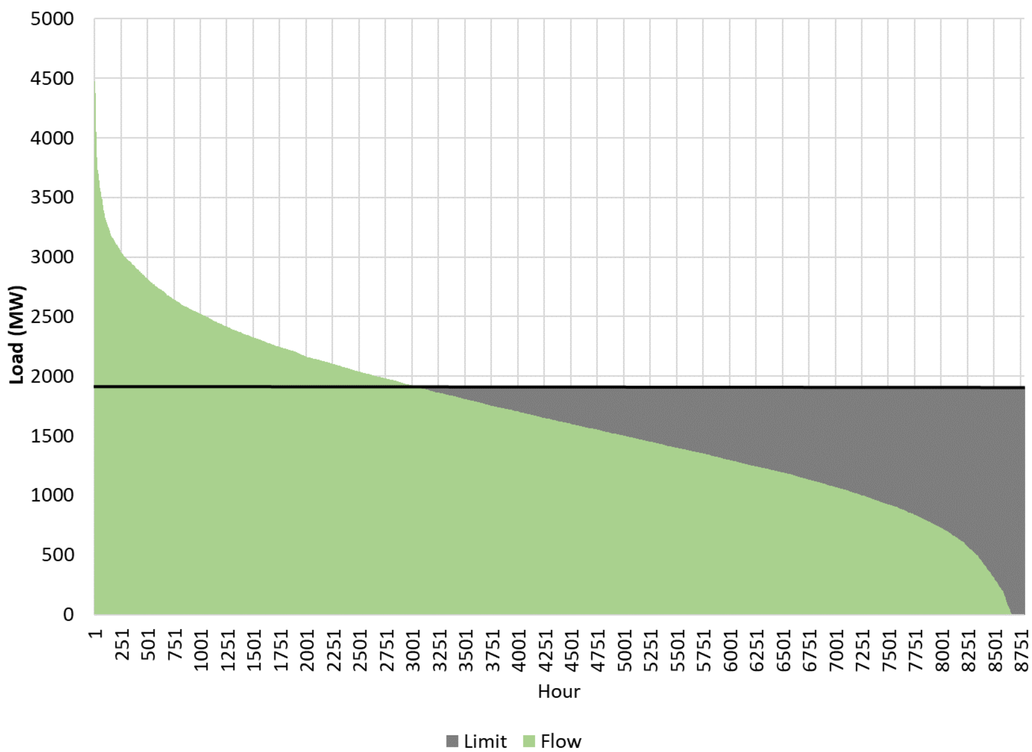


Figure 62 highlights the export flows on the SEMA/RI line in 2040 for the Base Transmission scenario, in which there were nearly 2000 hours where the limit of 3,400 MW per hour would have been exceeded. In only 6% of hours was the amount by which the limit would have been exceeded more than 1,000 MW, meaning that increasing the SEMA/RI export limit would alleviate nearly all congestion on the line.

Figure 62: SEMA/RI Export Flows, 2040 All Hours

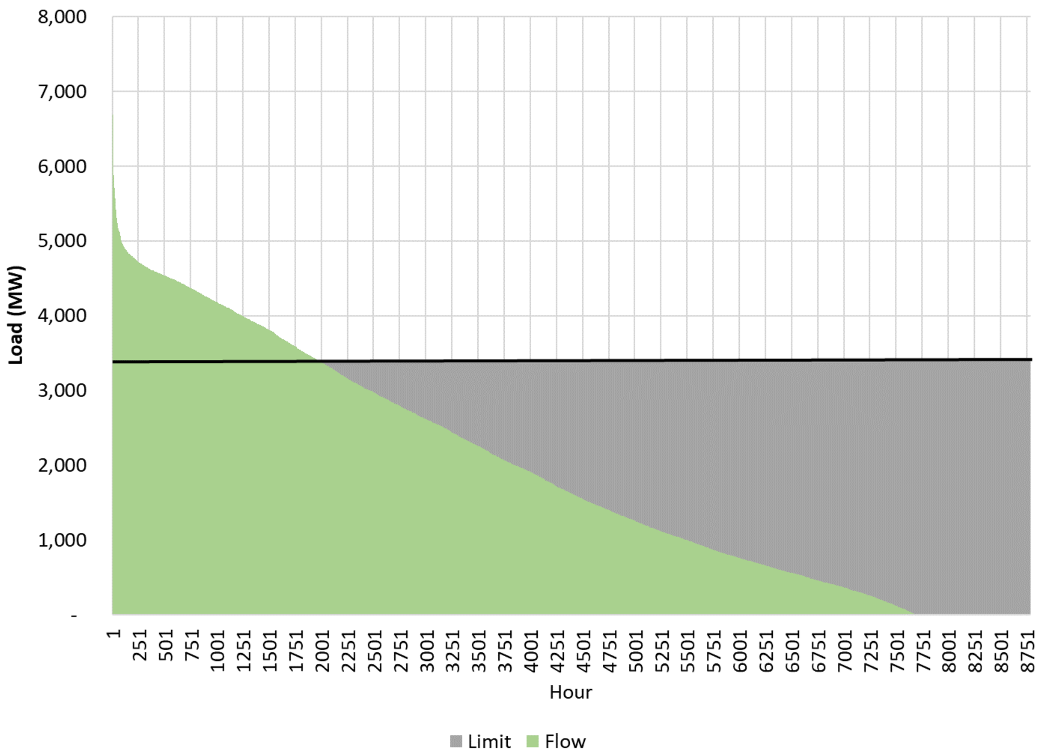


Figure 63 shows the northern to southern New England export flows in 2040, which are capped hourly at 2,900 MW in all cases excluding the Transmission cases. Absent the transfer constraint, flows exceeded the 2,900 MW limit in 2700 hours in 2040. Increasing the transfer capability from north to south by 500 MW would account for nearly one-half of the limit exceedances. As shown in Figure 64, flows from east to west would exceed the 3,000 MW transfer limit in only roughly 12% of all hours in 2040.

Figure 63: North to South Interface Flows, 2040 All Hours

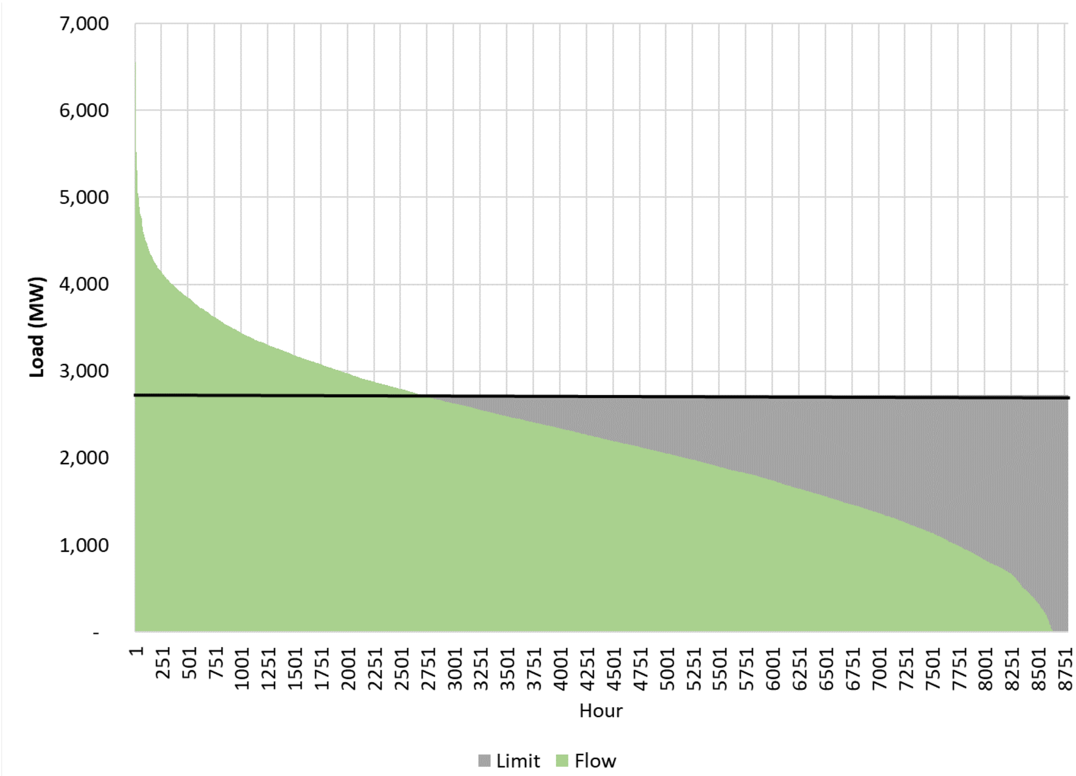
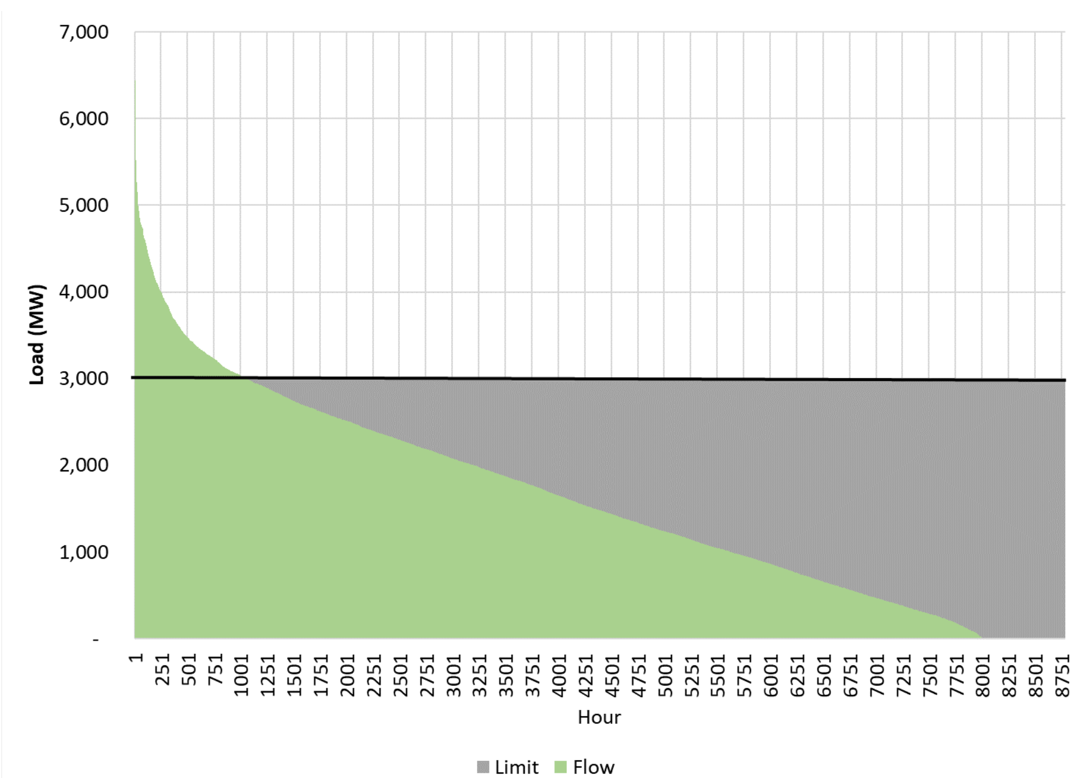


Figure 64: East to West Interface Flows, 2040 All Hours



7.2.2 Electrification Load Case Transmission Scenario

Flows for all hours in 2040 for the Electrification Transmission scenario were examined to determine which interfaces would have met the interface limit if constrained.

Figure 65 shows the hourly 2040 southern Maine to New Hampshire flows from the Electrification Transmission scenario in green compared to the limit in grey also noted with a black line. As in all other Electrification case scenarios and Base case scenarios, the hourly flow limit on this interface is 1,900 MW. Relaxing the constraint resulted in 4700 hours – more than one-half of the hours in the year - in which the flow on the interface exceeded the known 1,900 MW limit. Increasing the limit on the interface by 1,000 MW would result in just 1310 hours where the limit would have been exceeded.

Figure 65: Southern Maine to New Hampshire Interface Flows, 2040 All Hours

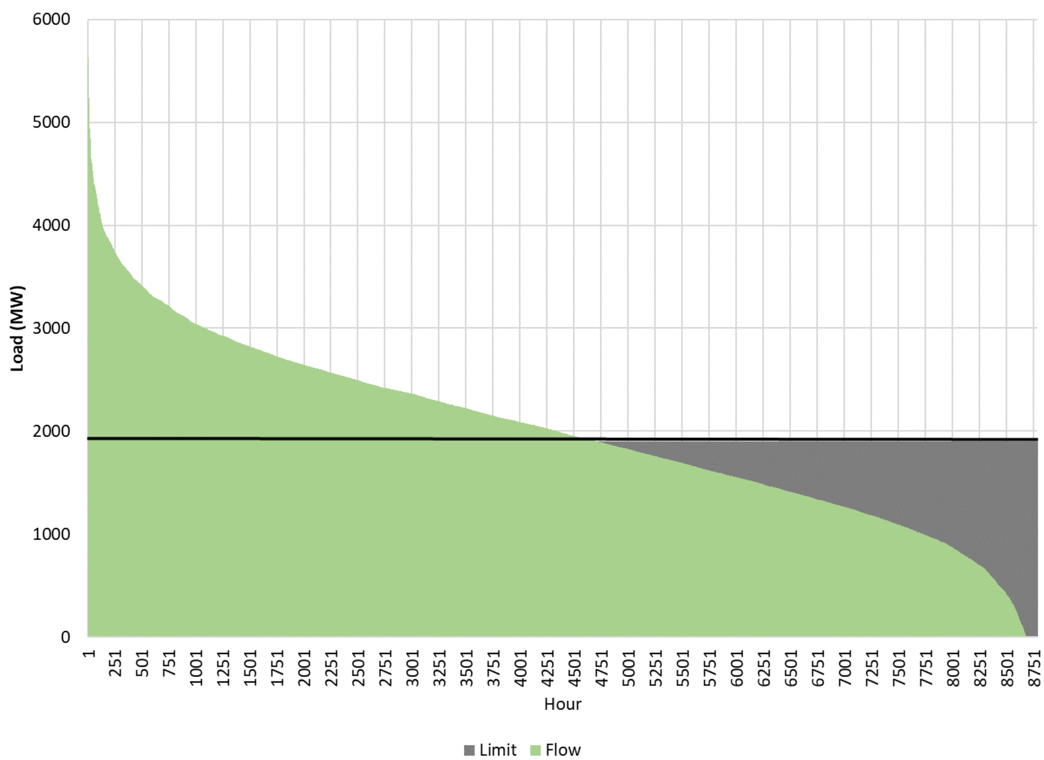


Figure 66 highlights the export flows on the SEMA/RI line in 2040 for the Electrification Transmission case, in which there were nearly 2650 hours where the limit of 3,400 MW per hour would have been exceeded. Whereas in the Base Transmission case, increasing the SEMA/RI export limit by 1,000 MW would have alleviated the congestion on the line in all but 6% of hours, increasing the limit by 1,000 MW in the Electrification Transmission case would only resolve the issue of flow constraints in half of the hours where constraints would have been relevant.

Figure 66: SEMA/RI Export Flows, 2040 All Hours

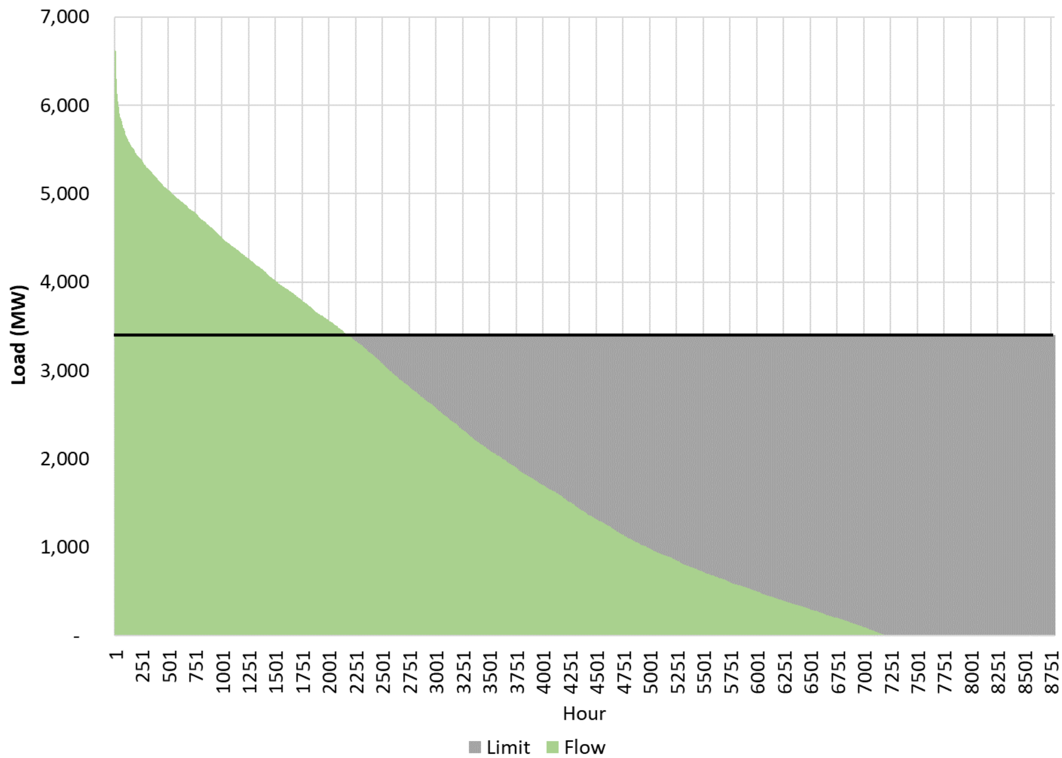


Figure 67 shows the northern to southern New England export flows in 2040, which are capped hourly at 2,900 MW in all cases excluding the Transmission cases. Absent the transfer constraint, flows exceeded the 2,900 MW limit in 2,800 hours in 2040. Increasing the transfer capability from north to south by 500 MW would account for just 40% of the limit exceedances. As shown in Figure 68, flows from east to west would exceed the 3,000 MW transfer limit in 24% of all hours in 2040, double the amount of occurrences in the Base Transmission case.

Figure 67: North to South Interface Flows, 2040 All Hours

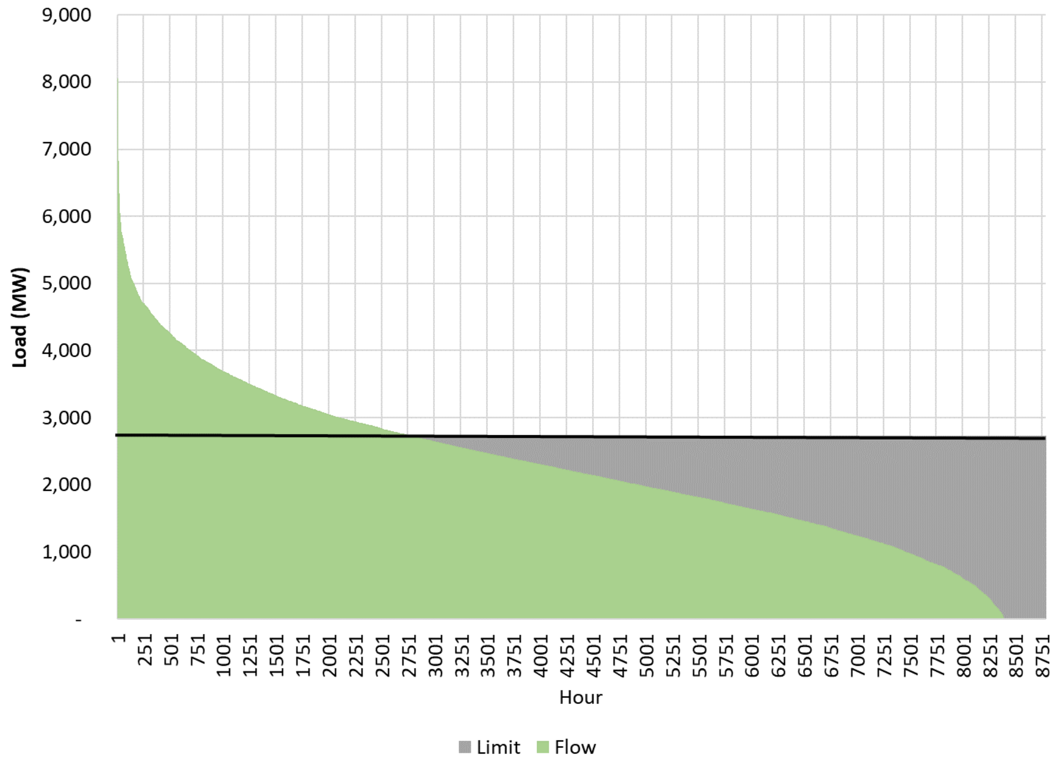
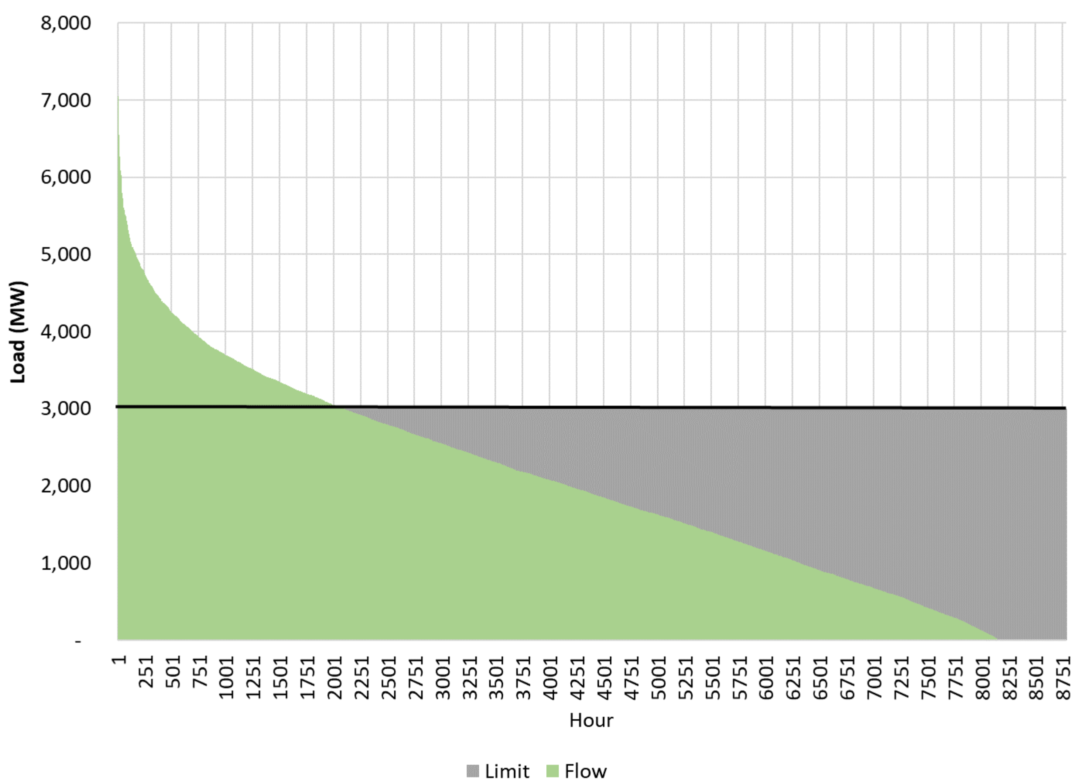


Figure 68: East to West Interface Flows, 2040 All Hours

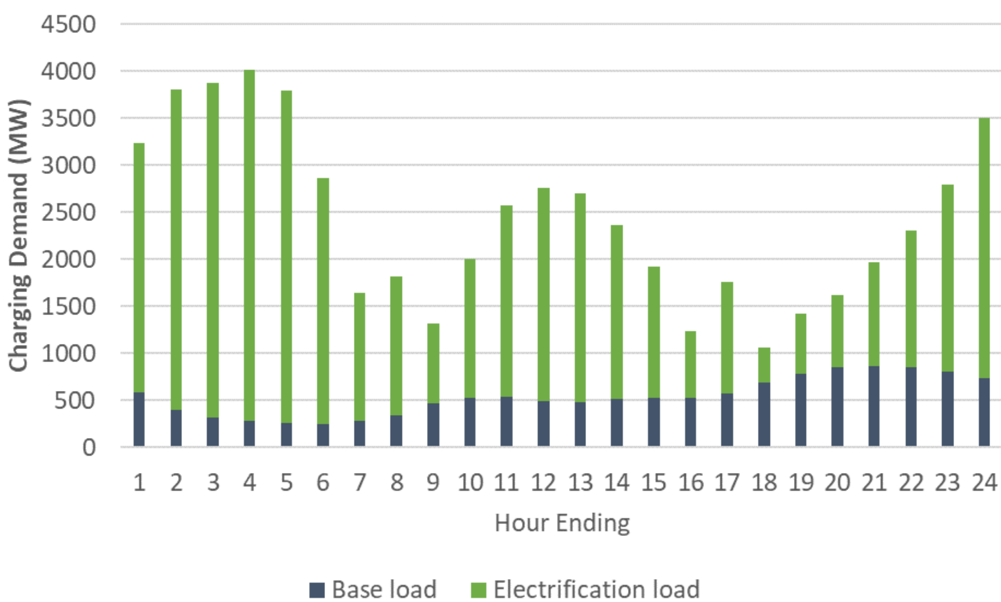


7.3 EV Charging Dynamics

Figure 69 and Figure 70 illustrate the difference in average hourly charging demand from EVs in winter versus summer months during 2040 for the Base Reference and Electrification Reference cases.[11] The blue bars represent the fixed Base case charging demand from EVs and the green bars represent the incremental Electrification case charging demand from EVs, which was modelled dynamically. Solar production in the summer months allowed more of the flexible Electrification charging load to occur in the morning hours between 6 and 9 am.

Average hourly seasonal EV charging demand by charging category is presented for 2040 winter months in Figure 71 and for 2040 summer months in Figure 72. Flexible charging during the daytime hours, particularly for the RL2, PL2, and PL3 charging categories, spreads out more across the day in summer months than in winter months, when daytime is shorter and there is less solar production. Table 9 of A1 provides an overview of charging availability by category.

Figure 69: Average Hourly EV Charging Demand, 2040 Winter Months



[11] Winter months include January, February, and December. Summer months include June, July, and August.

Figure 70: Average Hourly EV Charging Demand, 2040 Summer Months

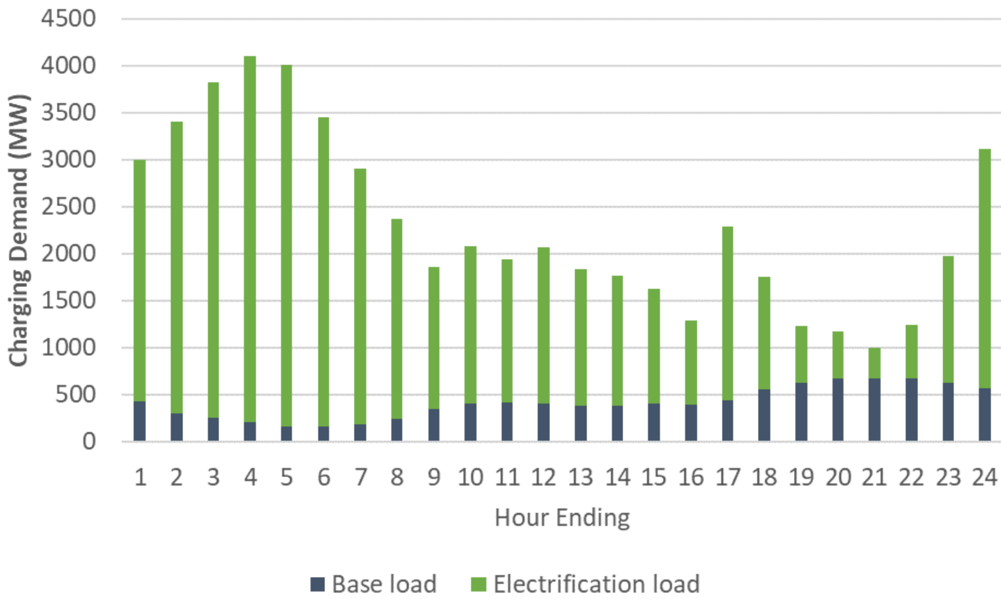


Figure 71: Average Hourly EV Charging Demand by Category, 2040 Winter Months

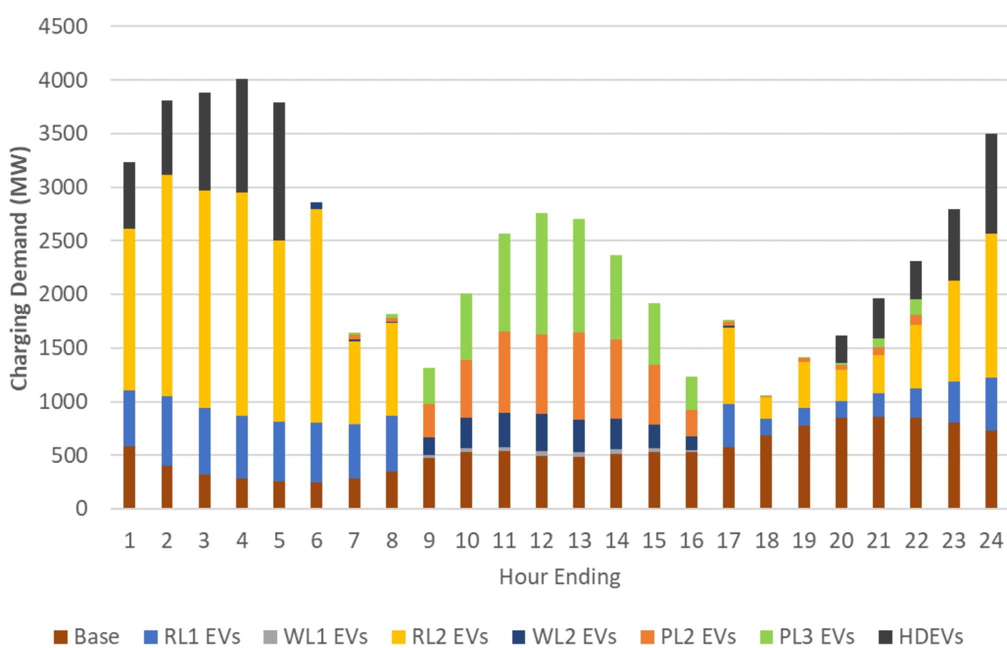
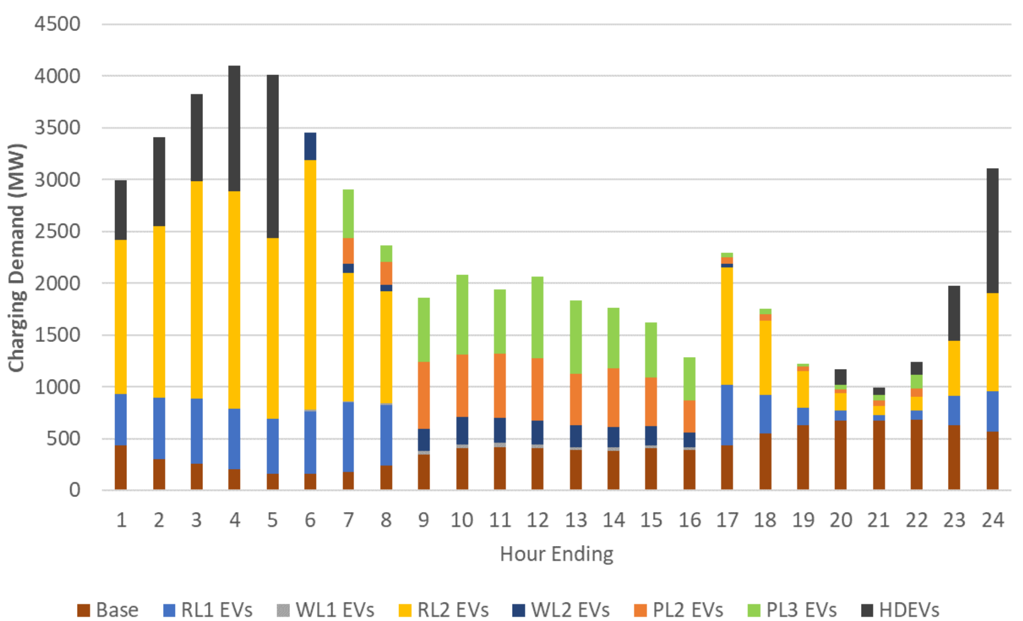


Figure 72: Average Hourly EV Charging Demand by Category, 2040 Summer Months



8 Financial Modeling

This appendix section presents two categories of results for each policy resource scenario:

1. Allocation of incremental regional additions of utility-scale PV solar, land-based wind, offshore wind, and storage capacity; and
2. Details of differential costs and benefits making up the Net Ratepayer Cost and Net Societal Cost in annual nominal dollars for calendar years 2021 through 2040 and in present value (2020) dollars calculated using a nominal discount rate of 7%. These results are presented at the detailed item level and at the category level provided in the body of the Report.

Charts and tabular results are supplemented with Excel file attachments where appropriate.

8.1 Incremental Resource Allocation

8.1.1 Base Load Case Scenarios

8.1.1.1 Base Reference Scenario (BR)

Base Reference Scenario incremental resources were allocated based on Connecticut's share of total regional energy load for each calendar year. These factors were roughly 24% for each year. Allocated resources by type and capacity in each vintage year are shown in Figure 73. The same resources, allocated by calendar year annual energy, are shown in Figure 74.

Figure 73: Incremental Resource Capacity Allocation to Connecticut, Scenario BR

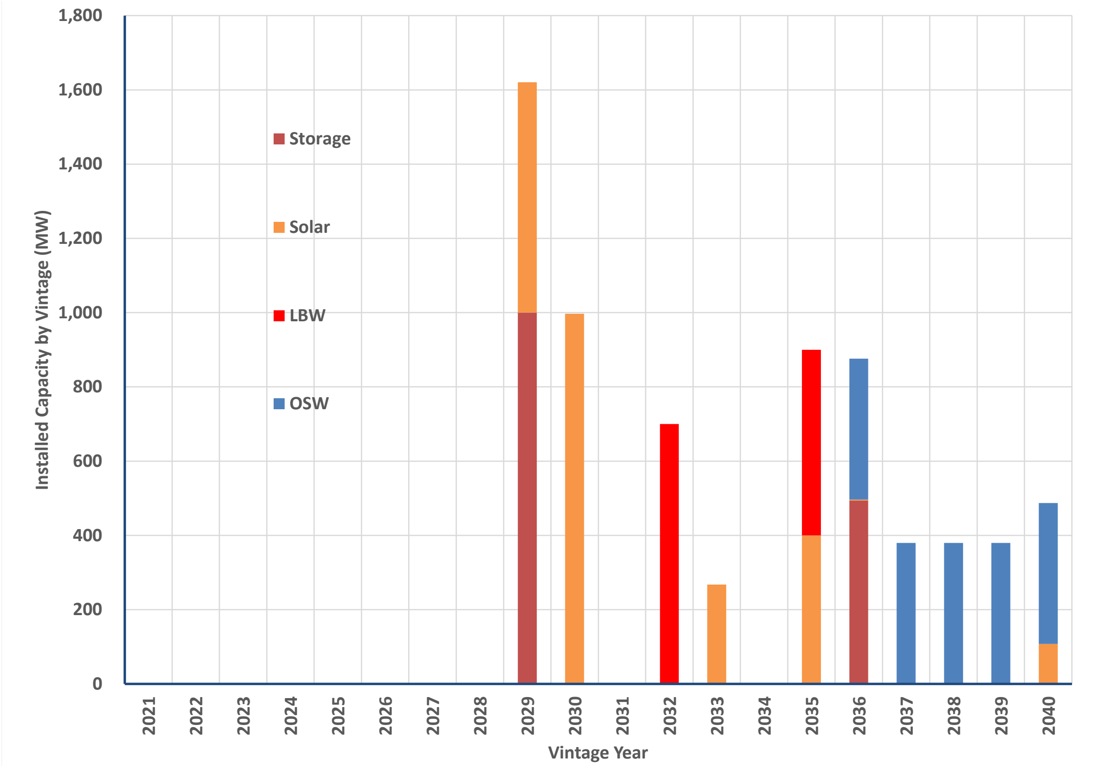
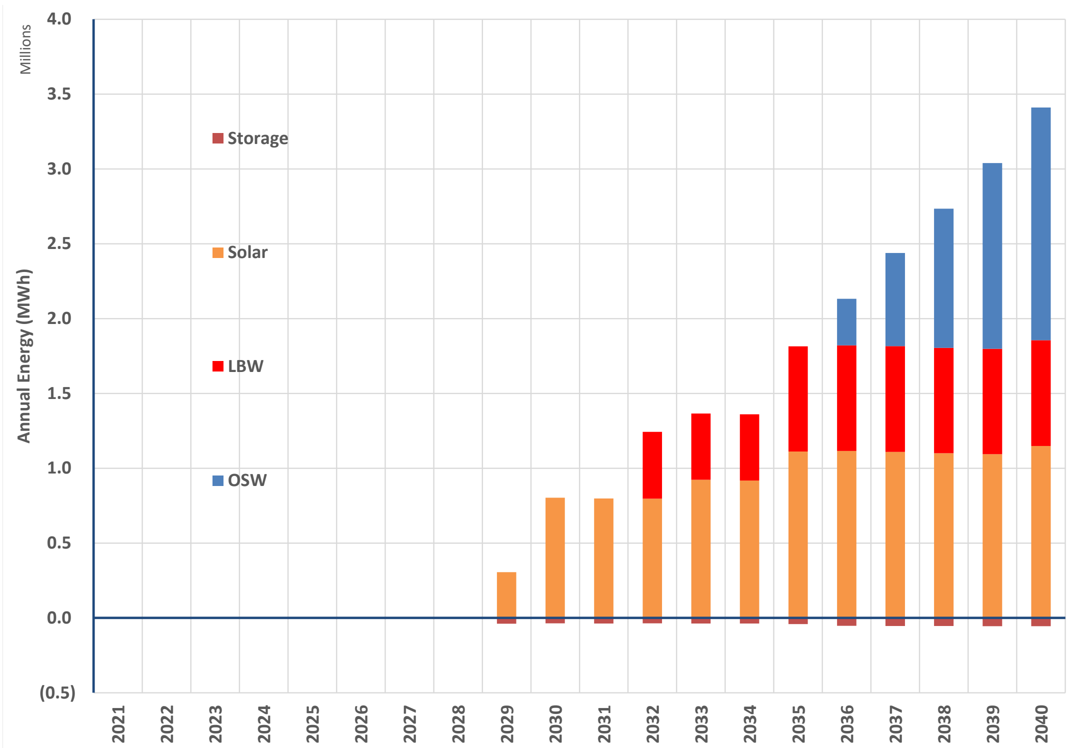


Figure 74: Incremental Resource Energy Allocation to Connecticut, Scenario BR

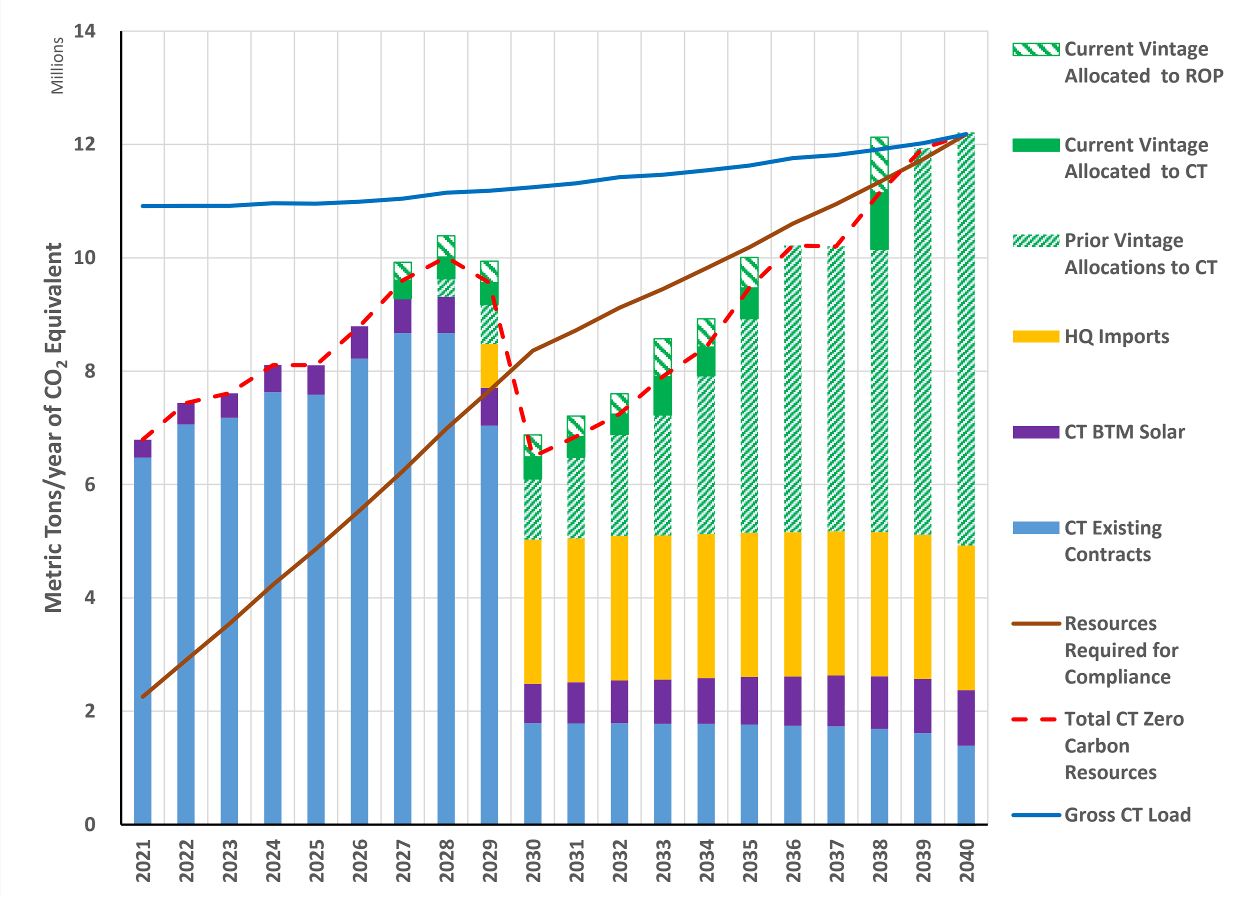


8.1.1.2 Base Balanced Blend Scenario (BB)

Incremental resources under all Policy Resource scenarios were allocated to prioritize the achievement of the Connecticut GHG inventory reduction goal of zero emissions in 2040. A target inventory in metric tons (MT) per year was established and converted to the amount of annual zero-carbon energy dedicated to Connecticut in 2040 that would be required to displace Connecticut energy load's contribution at a rate of 800 lb. (0.365 MT) of CO_2-equivalent per MWh. Figure 75 shows the process for the Base Balanced Blend Scenario. The light blue, purple, and orange bars represent fixed amounts of zero-carbon energy from existing contracts, the Connecticut portion of added BTM Solar, and "Policy Resources" (the HQ Import line applicable to the Reference Case all resource cases except for Millstone Extension case and the Millstone Extension environmental attribute assignment in that case). The shaded green bars represent the allocations from previous year vintages of Incremental Resources selected by the Aurora capacity expansion run. The green bars represent the current year vintage selection of incremental resources in two parts: The sum of the solid green bar and the hashed green bar are the total resource amount selected by Aurora. The former represents the portion assigned to Connecticut at the 50.32% rate established based on 2040 net requirements. The latter represents the remaining resource which is allocated to other states.

The vintage allocations carry back from 2040 to all other years, allowing for proper accounting of energy and capacity revenue credits and assignment of fixed costs by vintage. The dashed red line indicates the total zero-carbon resources claimed by Connecticut each year, while the brown line represents the target amount. The blue line represents the gross load that determines the requirement. Note that in 2040, the blue and brown lines converge, indicating that 100% of load is targeted to be covered by zero carbon resources. The shaded green bars in 2035 and 2036 are higher than the combination of the shaded green and solid green bar in 2034 because one of the resources added in 2034 is a phased OSW project. By taking on its share of the project in 2034, Connecticut receives the increased capacity and output in the next two years. The same applies to 2039 and 2040, based on the OSW resource selected for 2038. The red dashed line is below the brown line in 2030 through 2038, indicating that interim (pre-2040) annual goals have not been met.

Figure 75: Determination of Connecticut Incremental Resource Allocation, Scenario BB



This allocation process is summarized in Table 15. Here the units are GWh of zero-carbon energy per year, rather than MT/year. The column titled "CT Required Energy (GWh)" is the GWh equivalent of the amount of MTs needed to meet the brown line titled "Resources Required for Compliance" in Figure 75, and is equal to the sum of CT Existing Contracts (blue), CT BTM solar (purple), and HQ Imports (yellow) if applicable. If the existing GWh equivalent exceeds the amount needed, it is shown as a negative value in the table and is equal to the amount that is over the "Resources Required for Compliance" line. If the existing GWh equivalent falls below the brown line, it is shown as a positive value in the table and is equal to the difference between the line, and the sum of the CT Existing Contracts and CT BTM Solar and HQ imports.

Table 15: Vintage Incremental Resource Allocation, Scenario BB

Vintage Year	NE Total Incr'l Energy (GWh)	CT Required Energy (GWh)	CT Energy Allocation (GWh)	CT % of Vintage Total
2021	0	(12,505)	0	0.0%
2022	0	(12,507)	0	0.0%
2023	0	(11,217)	0	0.0%
2024	0	(10,687)	0	0.0%
2025	0	(8,937)	0	0.0%
2026	0	(8,961)	0	0.0%
2027	1,770	(8,391)	891	50.3%
2028	2,088	(6,414)	1,051	50.3%
2029	2,105	(2,263)	1,059	50.3%
2030	2,134	9,191	1,074	50.3%
2031	2,006	10,106	1,009	50.3%
2032	1,977	11,096	995	50.3%
2033	3,706	11,971	1,865	50.3%
2034	2,773	12,912	1,395	50.3%
2035	2,964	13,890	1,492	50.3%
2036	0	15,004	0	0.0%
2037	(0)	15,912	(0)	0.0%
2038	5,448	17,033	2,742	50.3%
2039	(20)	18,251	(10)	0.0%
2040	(172)	19,991	(87)	0.0%

The resulting cumulative allocation of incremental resource capacity to Connecticut by resource type is summarized by calendar year in Table 16: Cumulative Incremental Resource Capacity, Scenario BB.

Table 16: Cumulative Incremental Resource Capacity, Scenario BB

	Cumulative Incremental Resource Allocation			
Calendar Year	**CT Storage (MW)**	**CT Solar (MW)**	**CT LBW (MW)**	**CT OSW (MW)**
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	432	0	0
2028	0	933	0	0
2029	0	1,432	0	0
2030	0	1,928	0	0
2031	121	2,421	0	0
2032	372	2,912	0	0
2033	372	3,401	352	0
2034	372	3,384	352	388
2035	372	3,399	352	1,165
2036	372	3,382	352	1,745
2037	373	3,365	352	1,745
2038	542	3,348	352	2,545
2039	588	3,332	352	3,344
2040	1,060	3,316	352	3,745

8.1.1.3 Base Solar BTM PV Emphasis Scenario (BS)

As explained in the previous subsection, the incremental resources for the Scenario BS were determined based on Connecticut's requirements to meet its GHG reduction goals by 2040. Figure 76 shows this determination graphically, while Table 17 summarizes the calculations for this scenario.

Figure 76: Determination of Connecticut Incremental Resource Allocation, Scenario BS

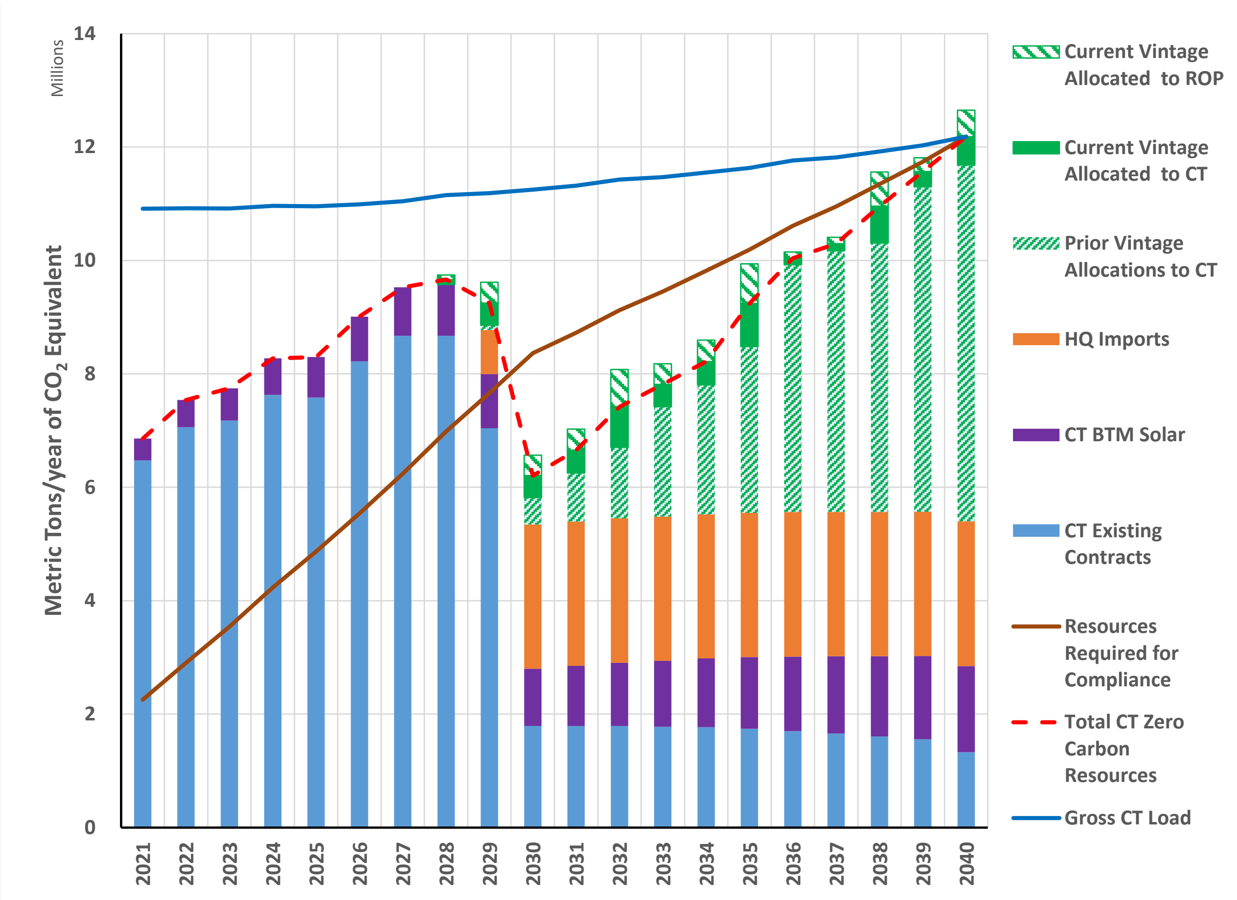


Table 17: Vintage Incremental Resource Allocation, Scenario BS

Vintage Year	NE Total Incr'l Energy (GWh)	CT Required Energy (GWh)	CT Energy Allocation (GWh)	CT % of Vintage Total
2021	0	(12,688)	0	0.0%
2022	0	(12,778)	0	0.0%
2023	0	(11,585)	0	0.0%
2024	0	(11,137)	0	0.0%
2025	0	(9,458)	0	0.0%
2026	0	(9,557)	0	0.0%
2027	0	(9,059)	0	0.0%
2028	451	(7,144)	234	51.9%
2029	2,091	(3,064)	1,085	51.9%
2030	2,056	8,329	1,067	51.9%
2031	2,128	9,170	1,104	51.9%
2032	3,788	10,106	1,966	51.9%
2033	2,072	10,936	1,075	51.9%
2034	2,167	11,838	1,124	51.9%
2035	4,022	12,792	2,087	51.9%
2036	620	13,903	322	51.9%
2037	656	14,845	340	51.9%
2038	3,449	15,924	1,790	51.9%
2039	1,413	17,008	733	51.9%
2040	2,664	18,695	1,383	51.9%

Cumulative capacity allocations by resource type are summarized in Table 18.

Table 18: Cumulative Incremental Resource Capacity, Scenario BS

Calendar Year	Cumulative Incremental Resource Allocation			
	CT Storage (MW)	CT Solar (MW)	CT LBW (MW)	CT OSW (MW)
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	105	0	0
2029	0	624	0	0
2030	0	1,140	0	0
2031	0	1,653	0	0
2032	260	2,163	363	0
2033	260	2,672	363	0
2034	260	2,870	363	197
2035	260	3,188	363	794
2036	308	3,348	363	1,391
2037	308	3,498	363	1,588
2038	760	3,481	623	1,984
2039	760	3,463	623	2,588
2040	1,279	3,446	623	3,221

8.1.1.4 Base Millstone Extension Scenario (BM)

The incremental resource allocation calculations for the Base Millstone Extension Scenario are summarized in Figure 77 and Table 19. Note that, in this scenario, the annual emission reduction goals are effectively achieved in all years.

Figure 77: Determination of Connecticut Incremental Resource Allocation, Scenario BM

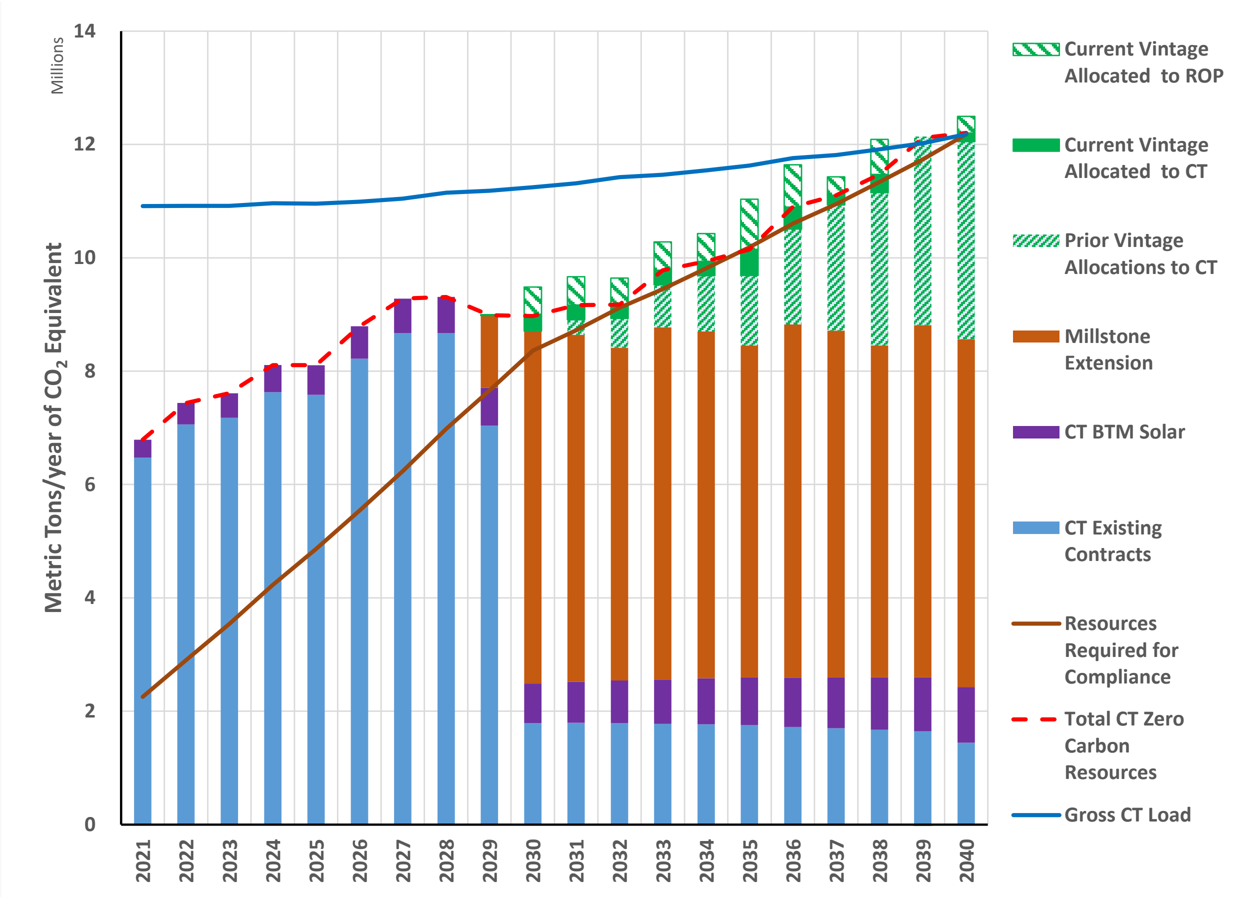


Table 19: Vintage Incremental Resource Allocation, Scenario BM

Vintage Year	NE Total Incr'l Energy (GWh)	CT Required Energy (GWh)	CT Energy Allocation (GWh)	CT % of Vintage Total
2021	0	(12,505)	0	0.0%
2022	0	(12,507)	0	0.0%
2023	0	(11,217)	0	0.0%
2024	0	(10,687)	0	0.0%
2025	0	(8,937)	0	0.0%
2026	0	(8,962)	0	0.0%
2027	0	(8,391)	0	0.0%
2028	0	(6,415)	0	0.0%
2029	43	(3,653)	15	34.1%
2030	2,142	(934)	730	34.1%
2031	2,090	219	712	34.1%
2032	1,953	1,939	665	34.1%
2033	2,083	1,857	710	34.1%
2034	2,044	3,071	696	34.1%
2035	3,708	4,785	1,263	34.1%
2036	3,120	4,912	1,063	34.1%
2037	1,360	6,148	463	34.1%
2038	2,588	7,955	882	34.1%
2039	(204)	8,054	(70)	0.0%
2040	1,224	9,959	417	34.1%

Cumulative capacity allocations by resource type are summarized in Table 20.

Table 20: Cumulative Incremental Resource Capacity, Scenario BM

	Cumulative Incremental Resource Allocation			
Calendar Year	**CT Storage (MW)**	**CT Solar (MW)**	**CT LBW (MW)**	**CT OSW (MW)**
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0
2029	0	7	0	0
2030	0	348	0	0
2031	0	687	0	0
2032	170	1,024	0	0
2033	170	1,360	0	0
2034	170	1,693	0	0
2035	170	2,025	238	0
2036	170	2,315	238	129
2037	170	2,304	238	392
2038	207	2,292	238	917
2039	524	2,281	238	1,180
2040	865	2,269	238	1,446

8.1.1.5 Base Transmission Scenario (BT)

Allocation calculations for the Base Transmission Scenario are summarized in Figure 78 and Table 21.

Figure 78: Determination of Connecticut Incremental Resource Allocation, Scenario BT

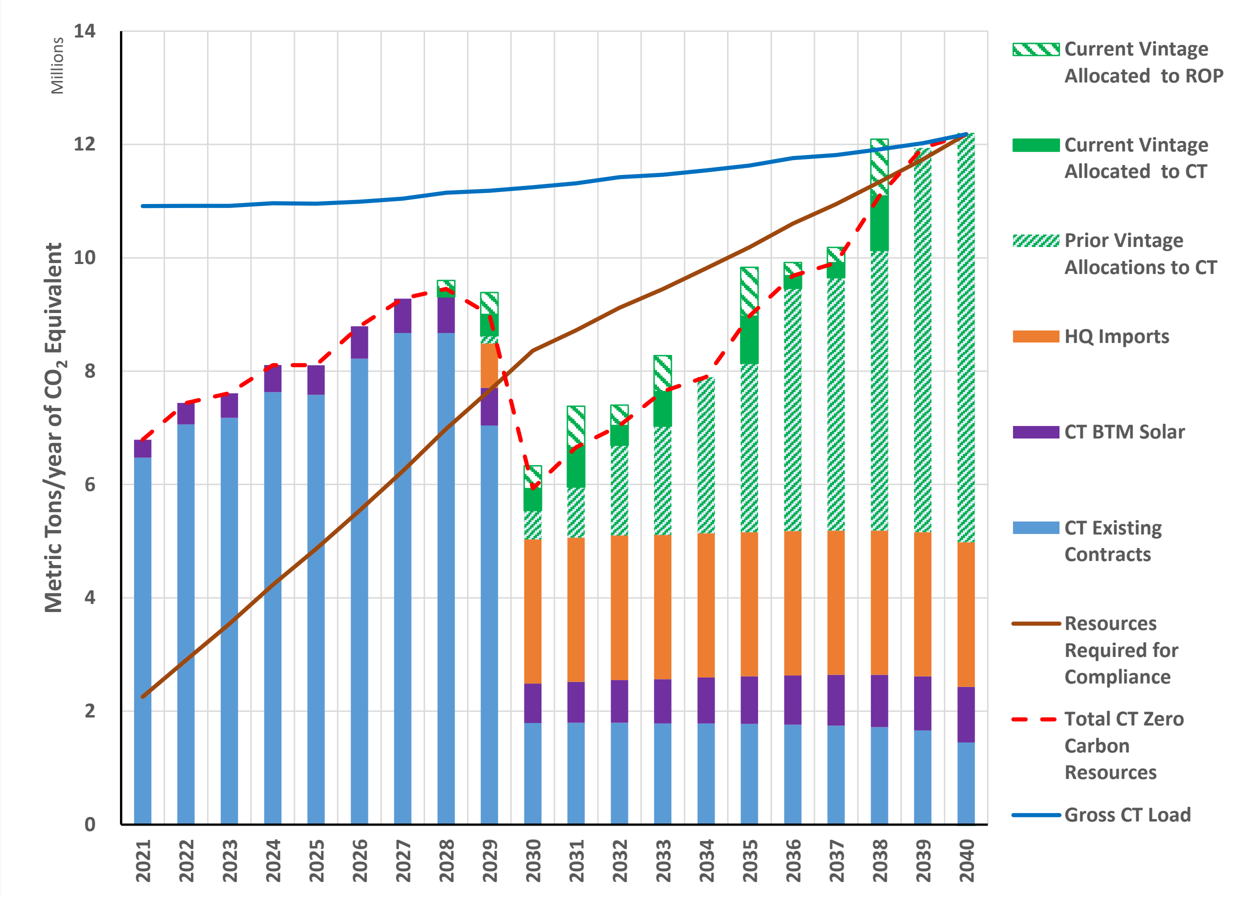


Table 21: Vintage Incremental Resource Allocation, Scenario BT

Vintage Year	NE Total Incr'l Energy (GWh)	CT Required Energy (GWh)	CT Energy Allocation (GWh)	CT % of Vintage Total
2021	0	(12,505)	0	0.0%
2022	0	(12,507)	0	0.0%
2023	0	(11,217)	0	0.0%
2024	0	(10,687)	0	0.0%
2025	0	(8,937)	0	0.0%
2026	0	(8,961)	0	0.0%
2027	0	(8,391)	0	0.0%
2028	796	(6,414)	391	49.1%
2029	2,091	(2,263)	1,026	49.1%
2030	2,175	9,191	1,067	49.1%
2031	3,933	10,106	1,930	49.1%
2032	1,945	11,096	955	49.1%
2033	3,423	11,971	1,680	49.1%
2034	0	12,912	0	0.0%
2035	4,671	13,890	2,293	49.1%
2036	1,261	15,004	619	49.1%
2037	1,468	15,912	720	49.1%
2038	5,408	17,033	2,654	49.1%
2039	0	18,251	0	0.0%
2040	(145)	19,991	(71)	0.0%

Cumulative capacity allocations are summarized in Table 22.

Table 22: Cumulative Incremental Resource Capacity, Scenario BT

	Cumulative Incremental Resource Allocation			
Calendar Year	CT Storage (MW)	CT Solar (MW)	CT LBW (MW)	CT OSW (MW)
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	192	0	0
2029	0	682	0	0
2030	0	1,170	0	0
2031	163	1,655	344	0
2032	408	2,137	344	0
2033	408	2,617	344	186
2034	408	2,604	344	373
2035	408	3,038	344	933
2036	408	3,320	344	1,308
2037	408	3,304	344	1,505
2038	862	3,287	344	2,482
2039	862	3,271	344	3,262
2040	1,246	3,255	344	3,653

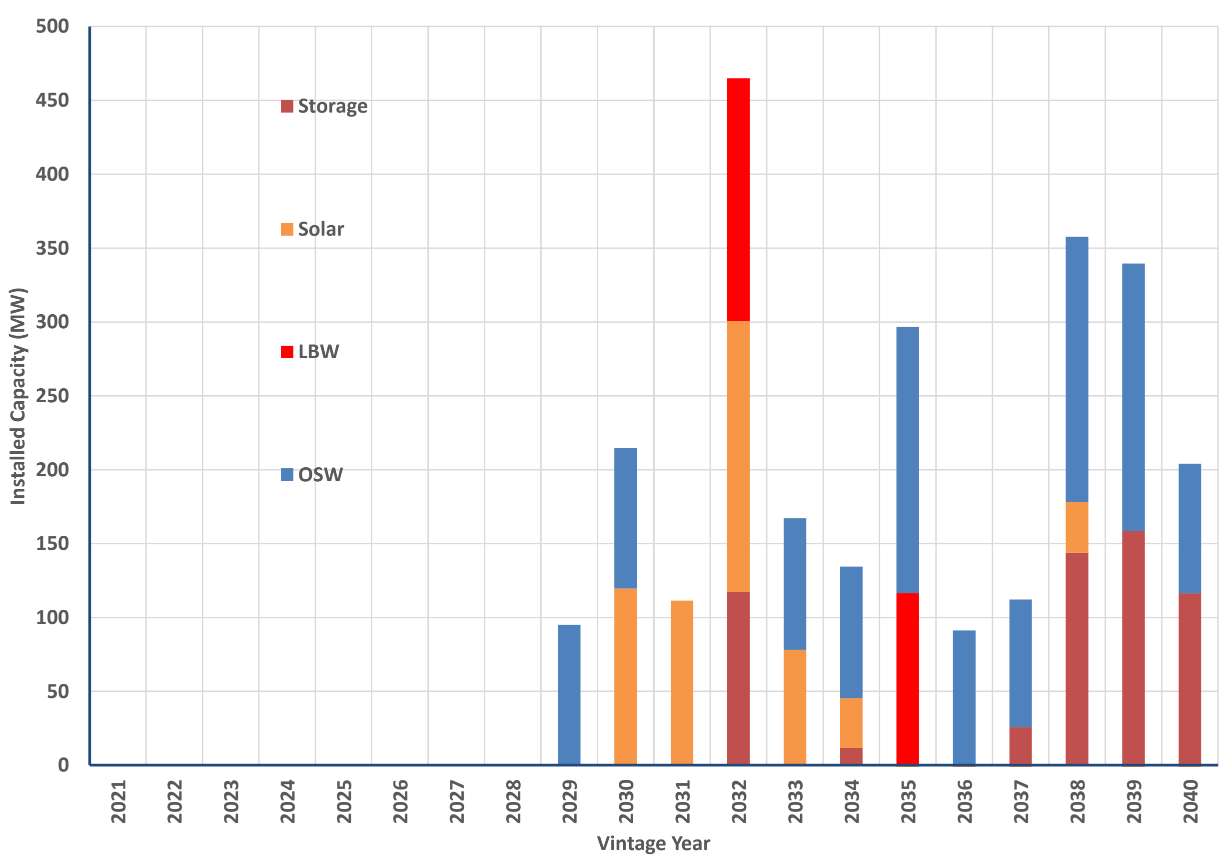
8.1.2 Electrification Load Case Scenarios

The incremental capacity allocations for the Electrification Load Case scenarios follow the same patterns as those of the corresponding Base Load Case scenarios. Tables and charts are presented in the following subsections.

8.1.2.1 Electrification Reference Scenario (ER)

As under the Base Load Case, incremental resources in the Electrification Reference Scenario are allocated based on Connecticut's share of the regional load for each calendar year. The resources added to the region and allocated to Connecticut are shown by type and vintage year in Figure 79.

Figure 79: Connecticut Allocation of Incremental Resource Capacity by Vintage, Scenario ER



8.1.2.2 Electrification Balanced Blend Scenario (EB)

Incremental resources under all Policy Resource scenarios were allocated to prioritize the achievement of Connecticut GHG inventory reduction goals by the year 2040. A target inventory in metric tons (MT) per year was established and converted to the amount of annual zero-carbon energy dedicated to Connecticut that would be required to displace Connecticut energy load's contribution at a rate of 800 lb. (0.365 MT) of CO_2-equivalent per MWh. The 2040 allocations carry backward to all study years, allowing for proper accounting of energy and capacity revenue credits and assignment of fixed costs by vintage.

This allocation process is summarized in Figure 80 and in Table 23. Here the units are GWh of zero-carbon energy per year, rather than MT/year.

Figure 80: Determination of Connecticut Incremental Resource Allocation, Scenario EB

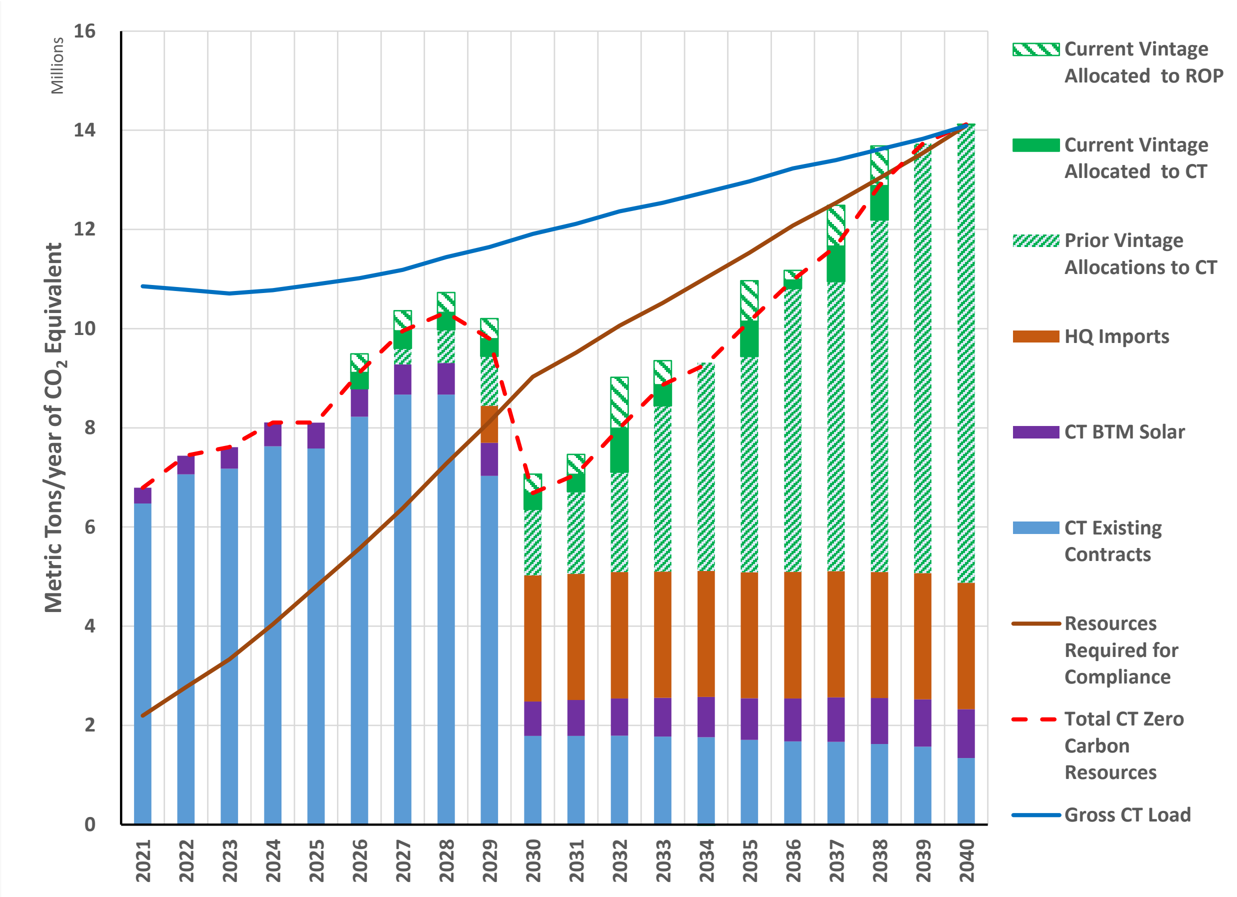


Table 23: Vintage Incremental Resource Allocation, Scenario EB

Vintage Year	NE Total Incr'l Energy (GWh)	CT Required Energy (GWh)	CT Energy Allocation (GWh)	CT % of Vintage Total
2021	0	(12,663)	0	0.0%
2022	0	(12,870)	0	0.0%
2023	0	(11,789)	0	0.0%
2024	0	(11,210)	0	0.0%
2025	0	(9,100)	0	0.0%
2026	1,931	(8,883)	897	46.4%
2027	2,088	(7,994)	970	46.4%
2028	2,070	(5,596)	961	46.4%
2029	2,094	(899)	972	46.4%
2030	1,960	11,035	910	46.4%
2031	2,072	12,298	963	46.4%
2032	5,274	13,678	2,450	46.4%
2033	2,504	14,932	1,163	46.4%
2034	(176)	16,284	(82)	0.0%
2035	4,214	17,751	1,957	46.4%
2036	1,006	19,249	467	46.4%
2037	4,229	20,463	1,964	46.4%
2038	4,122	21,895	1,915	46.4%
2039	0	23,345	0	0.0%
2040	32	25,402	15	46.4%

The resulting cumulative allocation of incremental resource capacity to Connecticut by resource type is summarized by calendar year in Table 24.

Table 24: Cumulative Incremental Resource Capacity, Scenario EB

	Cumulative Incremental Resource Allocation			
Calendar Year	CT Storage (MW)	CT Solar (MW)	CT LBW (MW)	CT OSW (MW)
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	425	0	0
2027	0	887	0	0
2028	0	1,347	0	0
2029	0	1,805	0	0
2030	232	2,260	0	0
2031	232	2,713	0	0
2032	464	2,900	325	358
2033	464	3,146	325	892
2034	929	3,131	325	1,245
2035	929	3,115	325	1,962
2036	929	3,100	557	2,503
2037	1,139	3,084	557	3,077
2038	1,603	3,069	557	4,208
2039	1,603	3,054	557	5,152
2040	1,603	3,045	557	5,710

8.1.2.3 Electrification Solar BTM PV Emphasis Scenario (ES)

The process for allocation of incremental resources to Connecticut for the Electrification Solar BTM PV Emphasis is summarized in Figure 81 and Table 25.

Figure 81: Determination of Connecticut Incremental Resource Allocation, Scenario ES

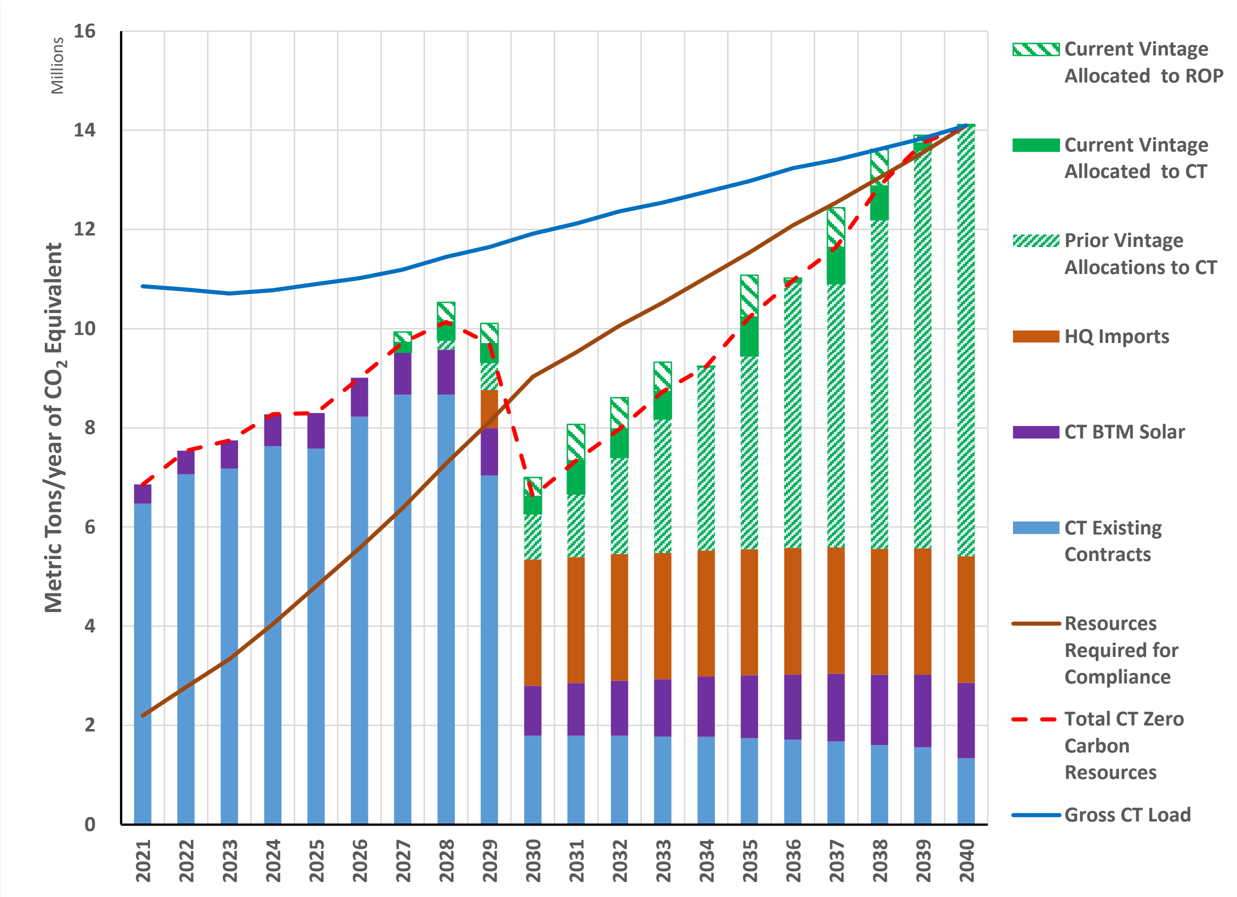


Table 25: Vintage Incremental Resource Allocation, Scenario ES

Vintage Year	NE Total Incr'l Energy (GWh)	CT Required Energy (GWh)	CT Energy Allocation (GWh)	CT % of Vintage Total
2021	0	(12,846)	0	0.0%
2022	0	(13,141)	0	0.0%
2023	0	(12,157)	0	0.0%
2024	0	(11,660)	0	0.0%
2025	0	(9,622)	0	0.0%
2026	0	(9,479)	0	0.0%
2027	1,122	(8,661)	539	48.0%
2028	2,088	(6,330)	1,002	48.0%
2029	2,166	(1,769)	1,040	48.0%
2030	2,024	10,169	972	48.0%
2031	3,874	11,376	1,860	48.0%
2032	3,330	12,700	1,599	48.0%
2033	3,148	13,909	1,511	48.0%
2034	47	15,165	23	48.0%
2035	4,475	16,485	2,148	48.0%
2036	239	17,934	115	48.0%
2037	4,223	19,167	2,028	48.0%
2038	3,923	20,621	1,884	48.0%
2039	830	21,989	398	48.0%
2040	99	23,950	48	48.0%

The resulting allocation of incremental resource capacity is shown on a cumulative basis in Table 26.

Table 26: Cumulative Incremental Resource Capacity, Scenario ES

	Cumulative Incremental Resource Allocation			
Calendar Year	CT Storage (MW)	CT Solar (MW)	CT LBW (MW)	CT OSW (MW)
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	265	0	0
2028	0	743	0	0
2029	0	1,220	0	0
2030	240	1,694	0	0
2031	240	2,165	336	0
2032	480	2,635	336	182
2033	480	3,046	336	547
2034	960	3,090	336	911
2035	960	3,139	336	1,653
2036	960	3,183	336	2,212
2037	1,080	3,188	336	2,793
2038	1,560	3,172	336	3,958
2039	1,560	3,156	576	4,742
2040	1,560	3,164	576	5,326

8.1.2.4 Electrification Millstone Extension Scenario (EM)

The process of allocating incremental resources to Connecticut under the Electrification Millstone Extension Scenario is summarized in Figure 82 and Table 27 for each vintage year.

Figure 82: Determination of Connecticut Incremental Resource Allocation, Scenario EM

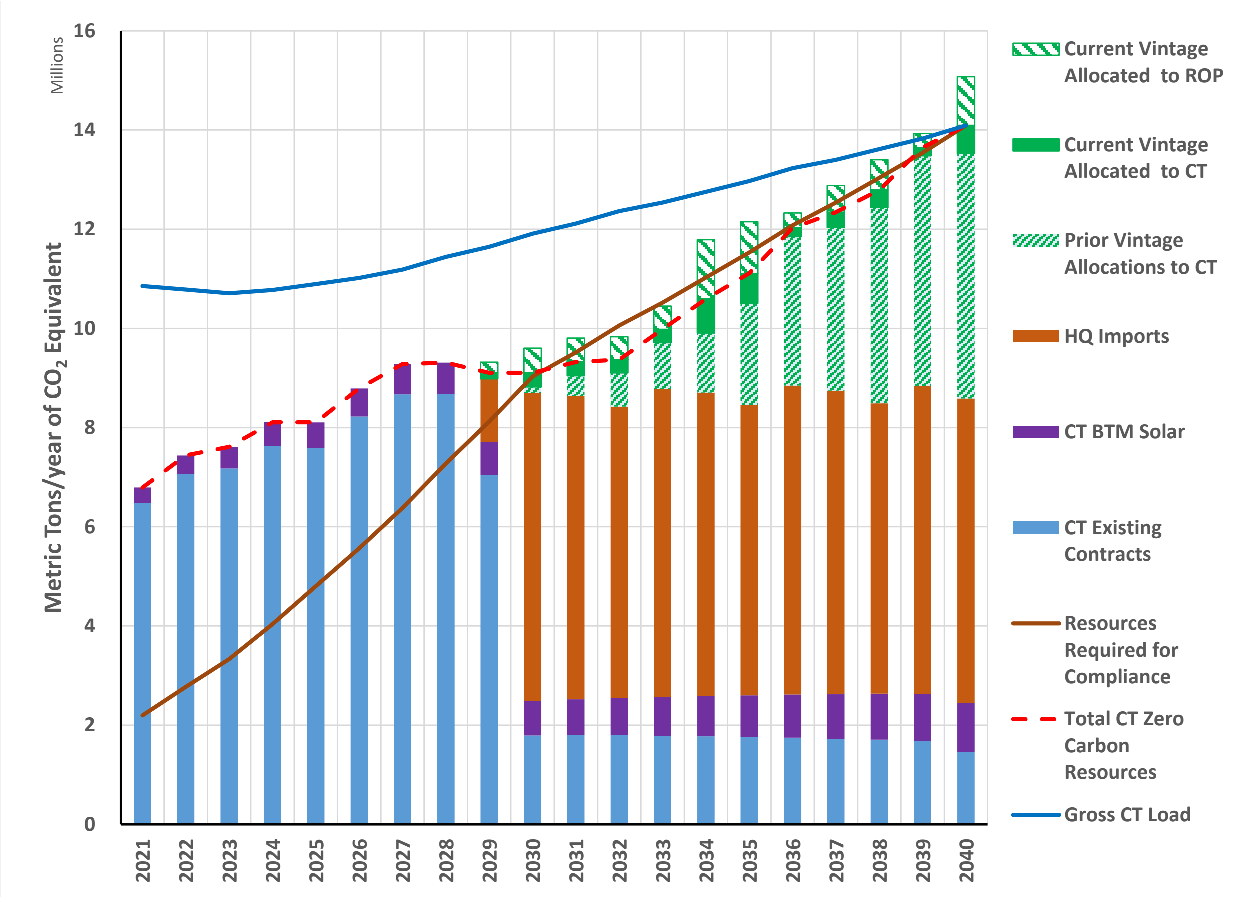


Table 27: Vintage Incremental Resource Allocation, Scenario EM

Vintage Year	NE Total Incr'l Energy (GWh)	CT Required Energy (GWh)	CT Energy Allocation (GWh)	CT % of Vintage Total
2021	0	(12,663)	0	0.0%
2022	0	(12,870)	0	0.0%
2023	0	(11,789)	0	0.0%
2024	0	(11,210)	0	0.0%
2025	0	(9,100)	0	0.0%
2026	0	(8,883)	0	0.0%
2027	0	(7,995)	0	0.0%
2028	0	(5,602)	0	0.0%
2029	922	(2,381)	337	36.5%
2030	2,149	902	785	36.5%
2031	2,097	2,418	766	36.5%
2032	2,014	4,508	736	36.5%
2033	2,029	4,800	741	36.5%
2034	5,194	6,389	1,898	36.5%
2035	4,523	8,479	1,652	36.5%
2036	1,308	8,904	478	36.5%
2037	2,325	10,446	850	36.5%
2038	2,660	12,541	972	36.5%
2039	1,244	12,949	454	36.5%
2040	4,258	15,181	1,556	36.5%

The resulting cumulative allocation of incremental resource capacity is shown by type in Table 28.

Table 28: Cumulative Incremental Resource Capacity, Scenario EM

	Cumulative Incremental Resource Allocation			
Calendar Year	CT Storage (MW)	CT Solar (MW)	CT LBW (MW)	CT OSW (MW)
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0
2029	0	161	0	0
2030	0	526	0	0
2031	0	888	0	0
2032	183	1,249	0	0
2033	183	1,608	0	0
2034	183	1,965	256	139
2035	183	2,321	438	420
2036	183	2,309	438	841
2037	240	2,474	438	1,115
2038	490	2,462	438	1,679
2039	855	2,449	438	2,116
2040	1,220	2,437	438	2,713

8.1.2.5 Electrification Transmission Scenario (ET)

The process of allocating incremental resources to Connecticut under the Electrification Transmission Scenario is summarized in Figure 83 and Table 29 for each vintage year.

Figure 83: Determination of Connecticut Incremental Resource Allocation, Scenario ET

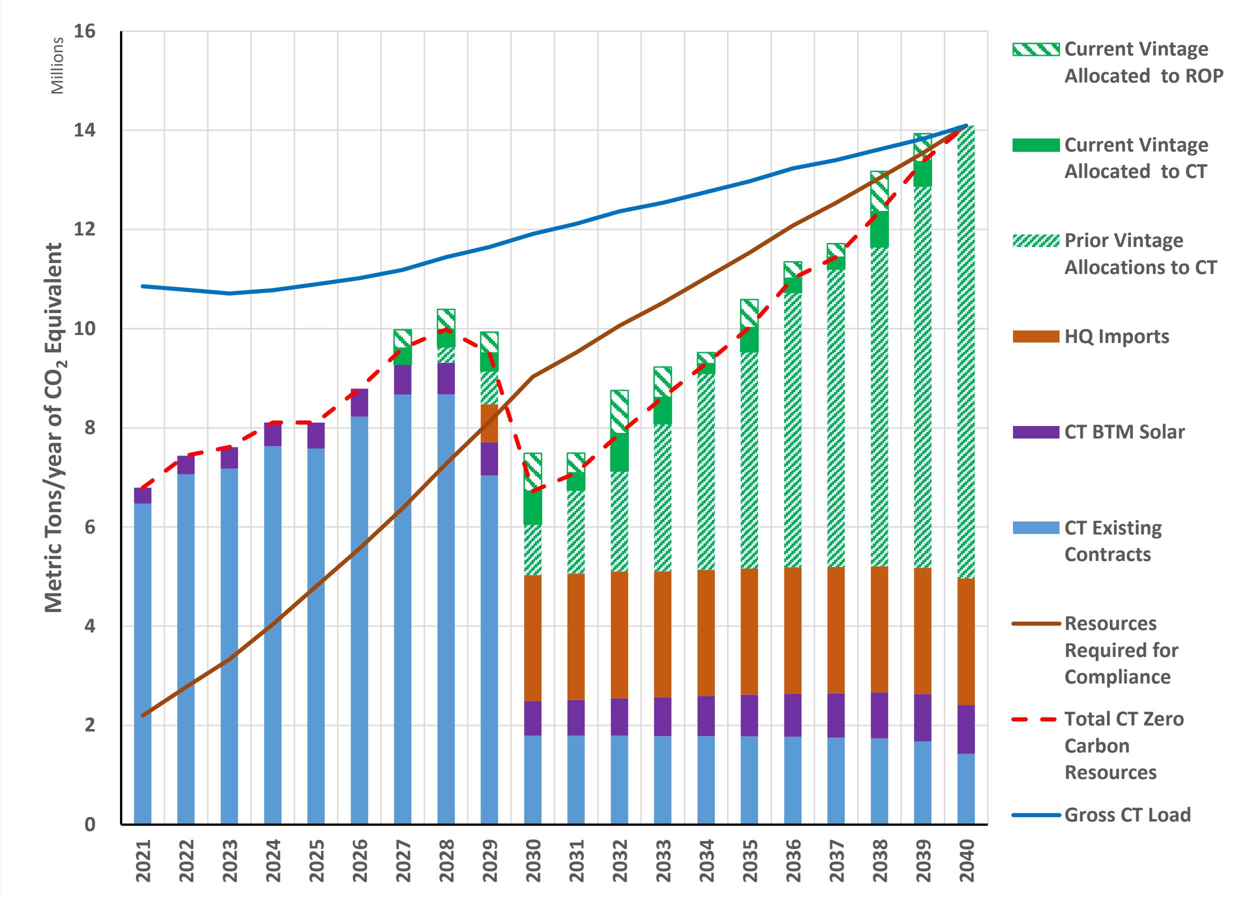


Table 29: Vintage Incremental Resource Allocation, Scenario ET

Vintage Year	NE Total Incr'l Energy (GWh)	CT Required Energy (GWh)	CT Energy Allocation (GWh)	CT % of Vintage Total
2021	0	(12,663)	0	0.0%
2022	0	(12,870)	0	0.0%
2023	0	(11,789)	0	0.0%
2024	0	(11,210)	0	0.0%
2025	0	(9,100)	0	0.0%
2026	0	(8,883)	0	0.0%
2027	1,923	(7,995)	894	46.5%
2028	2,088	(5,602)	971	46.5%
2029	2,153	(983)	1,001	46.5%
2030	3,924	11,015	1,824	46.5%
2031	2,048	12,280	952	46.5%
2032	4,481	13,664	2,083	46.5%
2033	3,147	14,918	1,463	46.5%
2034	1,151	16,229	535	46.5%
2035	2,902	17,546	1,349	46.5%
2036	1,703	18,991	792	46.5%
2037	1,419	20,234	659	46.5%
2038	4,203	21,587	1,954	46.5%
2039	2,910	23,053	1,353	46.5%
2040	0	25,166	0	0.0%

The resulting cumulative allocation of incremental resource capacity is shown by type in Table 30.

Table 30: Cumulative Incremental Resource Capacity, Scenario ET

	Cumulative Incremental Resource Allocation			
Calendar Year	CT Storage (MW)	CT Solar (MW)	CT LBW (MW)	CT OSW (MW)
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	432	0	0
2028	0	895	0	0
2029	0	1,355	0	0
2030	232	1,813	325	0
2031	232	2,269	325	0
2032	465	2,722	558	177
2033	465	3,095	558	535
2034	930	3,079	558	1,070
2035	930	3,064	558	1,615
2036	930	3,125	558	2,332
2037	1,055	3,109	558	2,692
2038	1,519	3,093	558	3,452
2039	1,519	3,078	558	4,397
2040	1,519	3,063	558	5,343

8.2 Differential Costs and Benefits

8.2.1 Base Load Case Scenarios

Cost and benefit results for the scenarios under the Base Load Case are presented in summary present value form in Table 31 below and in graphical detail in the subsections which follow. The costs and benefits are also provided in full detail in Excel file exhibits for each scenario.

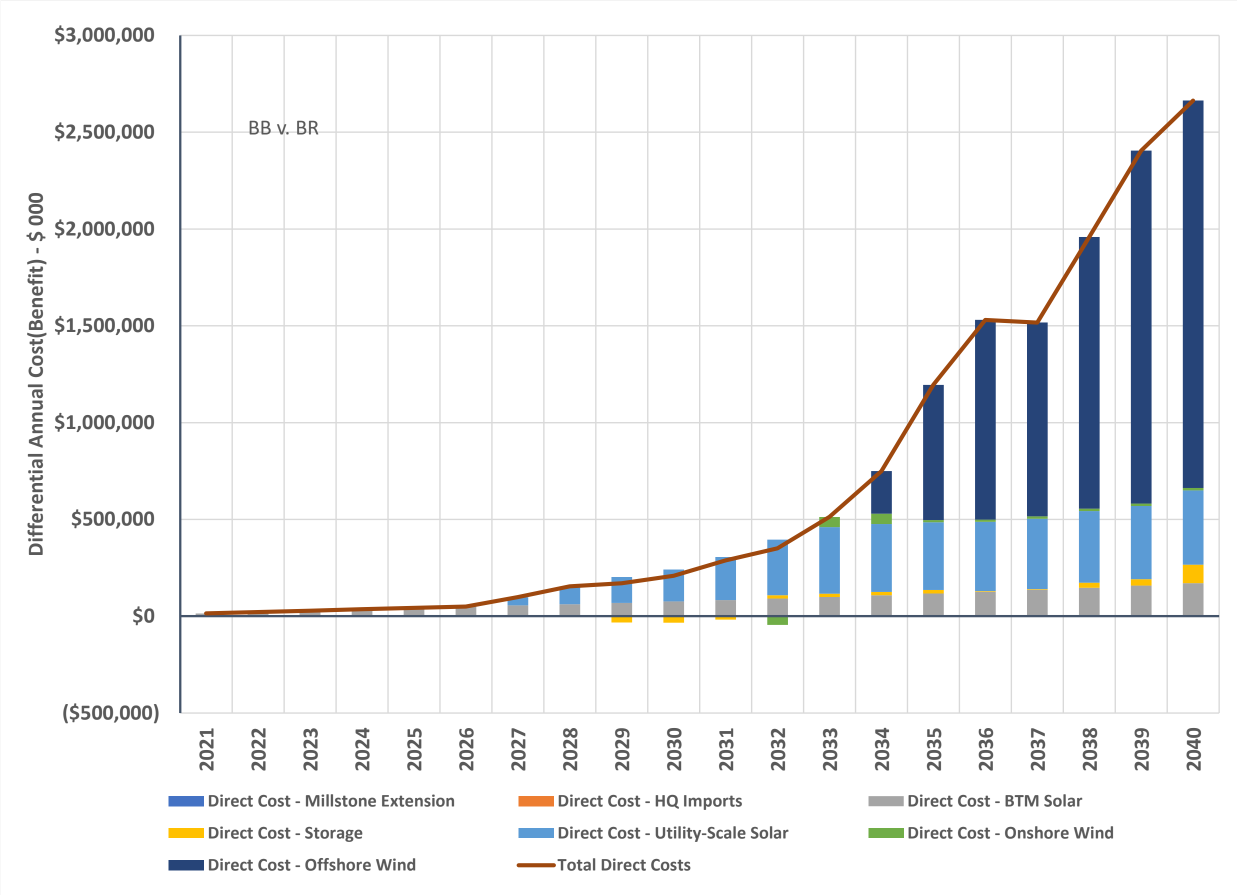
Table 31: Present Value Comparison of Base Load Case Scenarios

	Present Value of Differential Cost ($ MM)						
	Differentials v. BR				Differentials v. BB		
Cost Item or Category	**BB**	**BS**	**BM**	**BT**	**BS**	**BM**	**BT**
Market Energy Price Effects	($1,182)	($1,214)	($1,069)	($870)	($31)	$114	$313
Market Capacity Price Effects	$1,129	$626	($495)	$1,151	($503)	($1,624)	$22
Energy Revenue - Existing Contracts	$334	$351	$247	$203	$17	($86)	($131)
Capacity Revenue - Existing Contracts	$0	$0	$0	$0	$0	$0	$0
Direct Cost - Millstone Extension	$0	$0	$2,334	$0	$0	$2,334	$0
Energy Revenue - Millstone Extension	$0	$0	($1,486)	$0	$0	($1,486)	$0
Direct Cost - HQ Imports	$0	$0	($3,862)	$0	$0	($3,862)	$0
Energy Revenue - HQ Imports	$208	$189	$1,507	$125	($19)	$1,299	($83)
Capacity Revenue - HQ Imports	($162)	($121)	$277	($165)	$41	$439	($3)
Direct Cost - BTM Solar	$716	$2,388	$716	$716	$1,672	$0	$0
Energy Wholesale Value - BTM Solar	($74)	$115	($38)	$11	$189	$37	$85
Direct Cost - Storage	$28	$7	($71)	$74	($21)	($99)	$45
Energy Revenue - Storage	($33)	($40)	$38	($43)	($7)	$71	($9)
Direct Cost - Utility-Scale Solar	$1,425	$1,093	$506	$1,039	($332)	($919)	($385)
Energy Revenue - Utility-Scale Solar	($482)	($337)	($117)	($502)	$144	$365	($20)
Direct Cost - Onshore Wind	$45	$184	($100)	$127	$140	($145)	$83
Energy Revenue - Onshore Wind	$6	($31)	$40	($48)	($37)	$34	($54)
Direct Cost - Offshore Wind	$2,441	$1,855	$456	$2,222	($586)	($1,985)	($219)
Energy Revenue - Offshore Wind	($358)	($245)	($55)	($370)	$113	$303	($13)
Capacity Revenue - Incremental Resources	($277)	($210)	($77)	($322)	$67	$200	($45)
Societal Cost of Carbon Emissions	($609)	($601)	($804)	($530)	$8	($195)	$79
Subtotals							
Millstone Extension Direct Cost	$0	$0	$2,334	$0	$0	$2,334	$0
Millstone Extension Market Value	$0	$0	($1,486)	$0	$0	($1,486)	$0
Wholesale Market Price Effects	($53)	($588)	($1,564)	$282	($535)	($1,511)	$335
Revenue Effect on Existing Contracts	$334	$351	$247	$203	$17	($86)	($131)
Incremental Resource Direct Cost	$4,655	$5,528	($2,355)	$4,179	$873	($7,010)	($477)
Incremental Resource Market Value	($1,172)	($680)	$1,575	($1,315)	$492	$2,748	($143)
Societal Cost of GHG Effects	($609)	($601)	($804)	($530)	$8	($195)	$79
Total Societal Cost	$3,155	$4,010	($2,051)	$2,819	$856	($5,206)	($336)
Total Ratepayer Cost	$3,764	$4,612	($1,247)	$3,348	$848	($5,011)	($415)

8.2.1.1 Balanced Blend v. Reference (BB v. BR)

The annual costs and benefits for the Base Balanced Blend Scenario are presented as differentials relative to the Base Reference Scenario in three charts grouping items into major categories. Figure 84 shows the direct costs for all added Connecticut-procured zero-carbon resources added under the scenario, including the HQ Import line, more Connecticut solar BTM PV resources than included in the Base Reference Scenario, and the Connecticut share of incremental resources selected in the Aurora simulation and optimization process relative to the Base Reference Scenario selections.

Figure 84: Direct Costs, Scenario BB



Market price effect details are charted by year in Figure 85.

Figure 85: Market Price Effects, Scenario BB

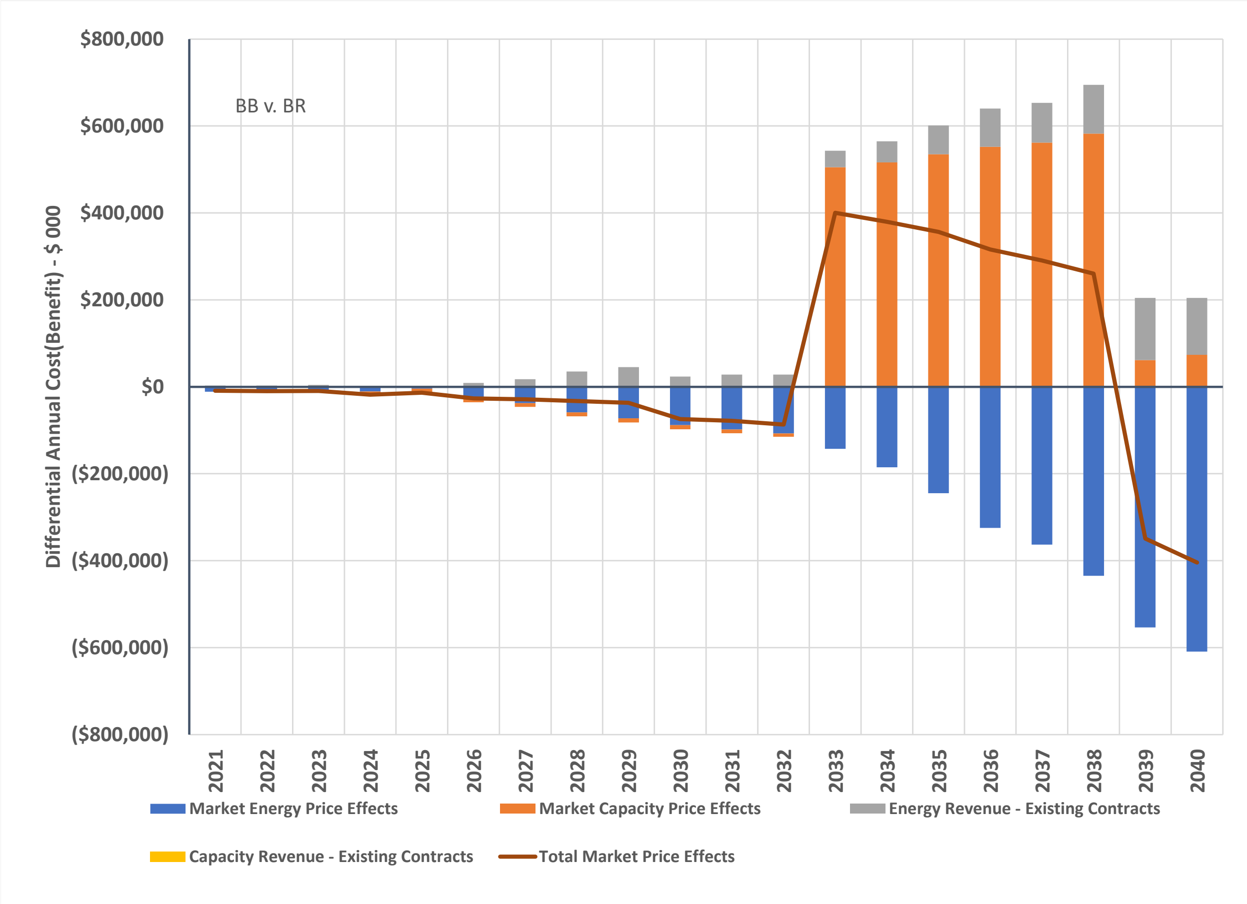
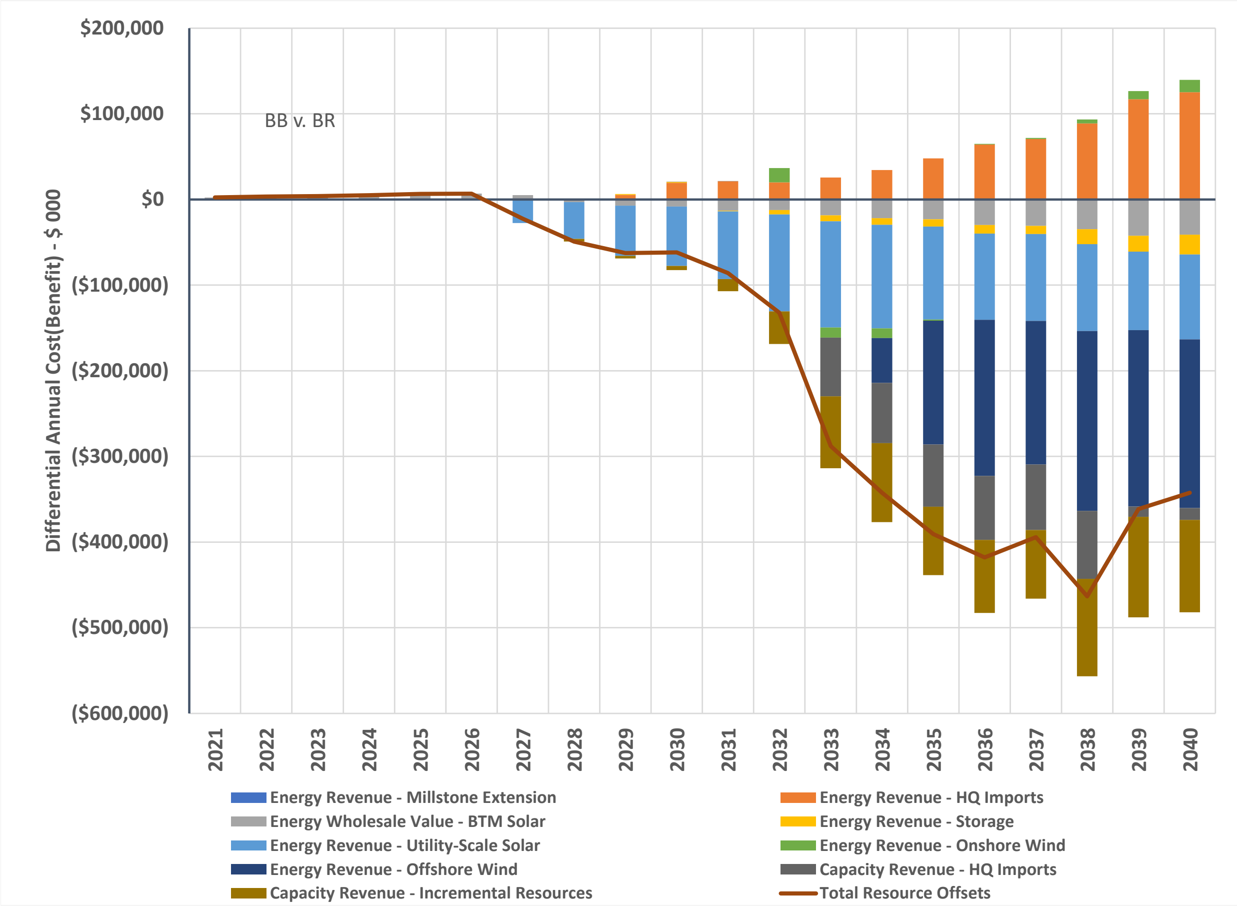


Figure 86 shows the direct cost offsets in the form of energy and capacity payments from the various added zero-carbon resources under the scenario.

Figure 86: Market Revenue Offsets, Scenario BB

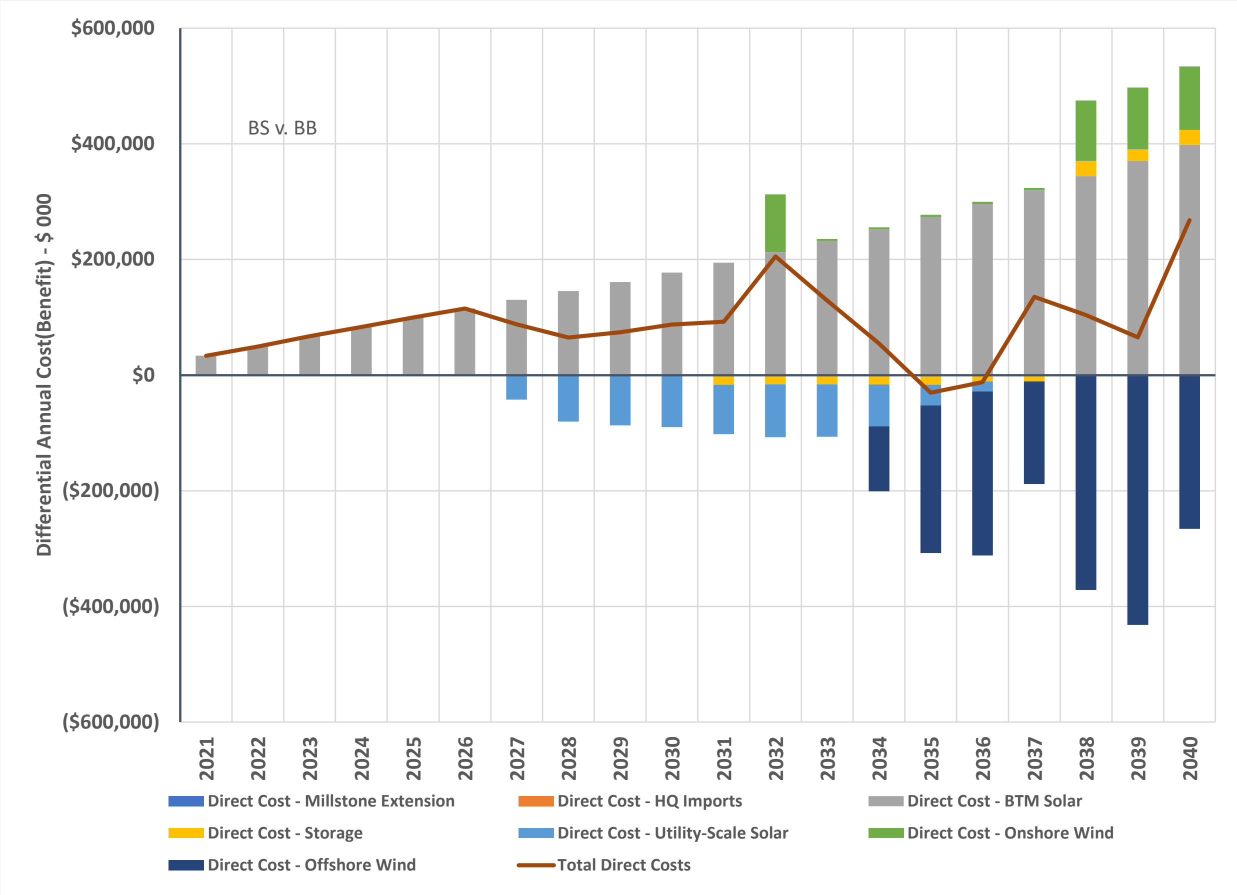


8.2.1.2 Solar BTM PV Emphasis v. Balanced Blend (BS v BB)

Details of the Base Solar BTM PV Emphasis Scenario financial analysis are presented in an Excel workbook in Exhibit BS and in the charts presented below. The Excel exhibit includes annual nominal dollar and present value cost details as differentials between this scenario and both the Base Reference Scenario and the Base Balanced Blend Scenario. It also includes the charts for this scenario that appear in the main Report and in this appendix section.

Figure 87 shows the differential direct costs for the scenario against the direct costs of the Base Balanced Blend Scenario.

Figure 87. Direct Costs, Scenario BS



Market price effects of the scenario, relative to the Base Balanced Blend Scenario, are shown in Figure 88.

Figure 88: Market Price Effects, Scenario BS

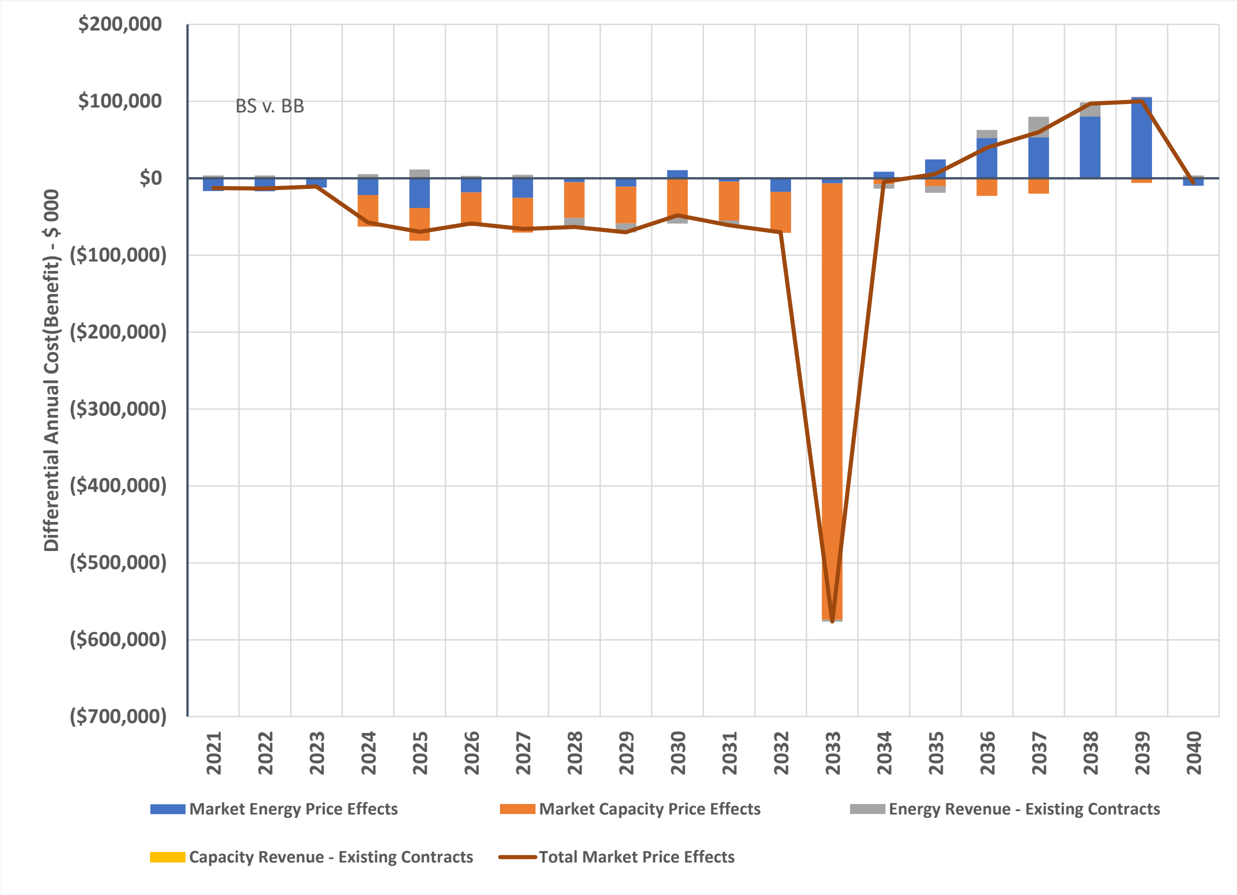
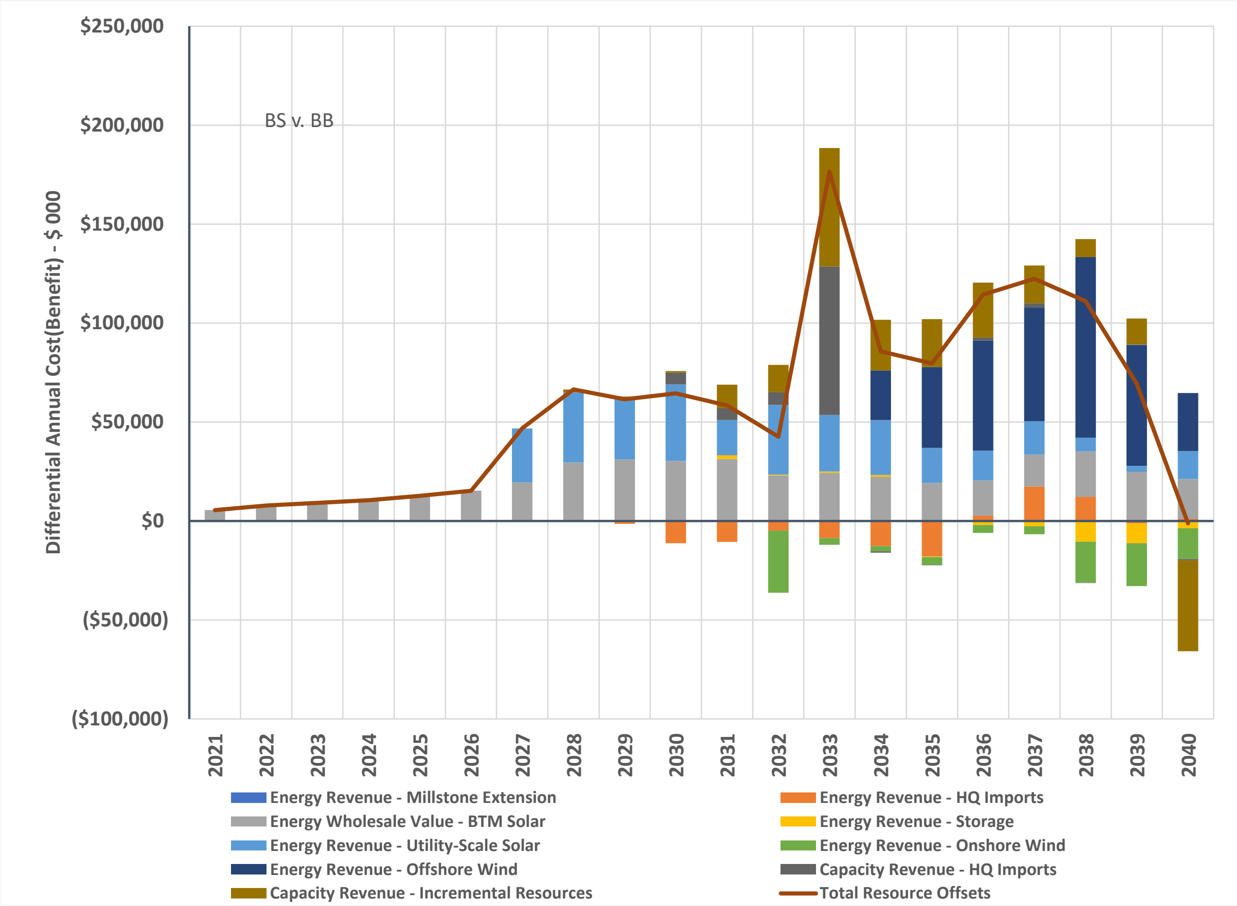


Figure 89 shows the direct revenue offsets for this scenario, relative to the Base Balanced Blend Scenario.

Figure 89: Market Revenue Offsets, Scenario BS

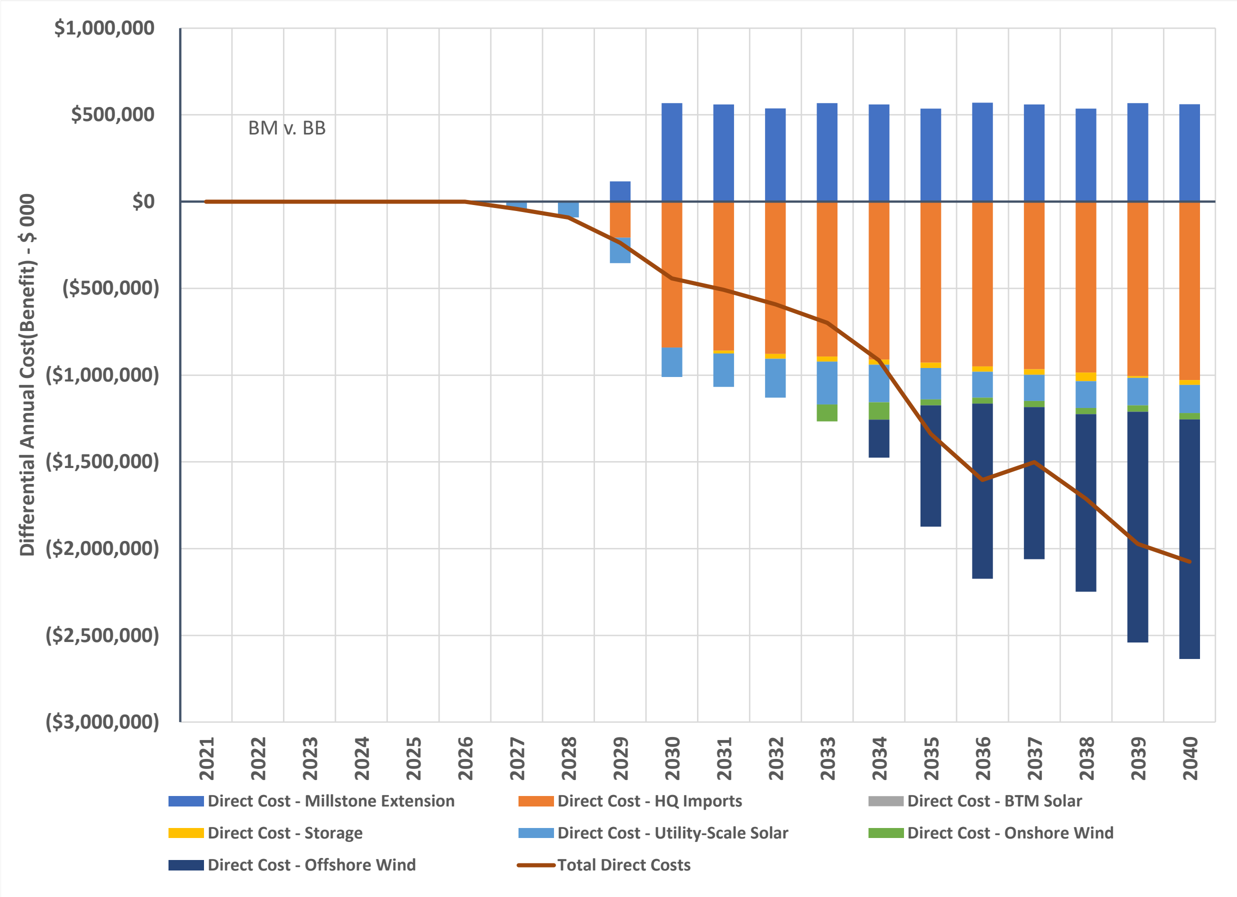


8.2.1.3 Millstone Extension v. Balanced Blend (BM v. BB)

Details of the Base Millstone Extension Scenario financial analysis are presented in an Excel workbook in Exhibit BM and in the charts presented below. The Excel exhibit includes annual nominal dollar and present value cost details as differentials between this scenario and both the Base Reference Scenario and the Base Balanced Blend Scenario. It also includes the charts for this scenario that appear in the main Report and in this appendix section.

Figure 90 shows the differential direct costs for the scenario against the direct costs of the Base Balanced Blend Scenario.

Figure 90: Direct Costs, Scenario BM



Market price effects of the scenario, relative to the Base Balanced Blend Scenario, are shown in Figure 91.

Figure 91: Market Price Effects, Scenario BM

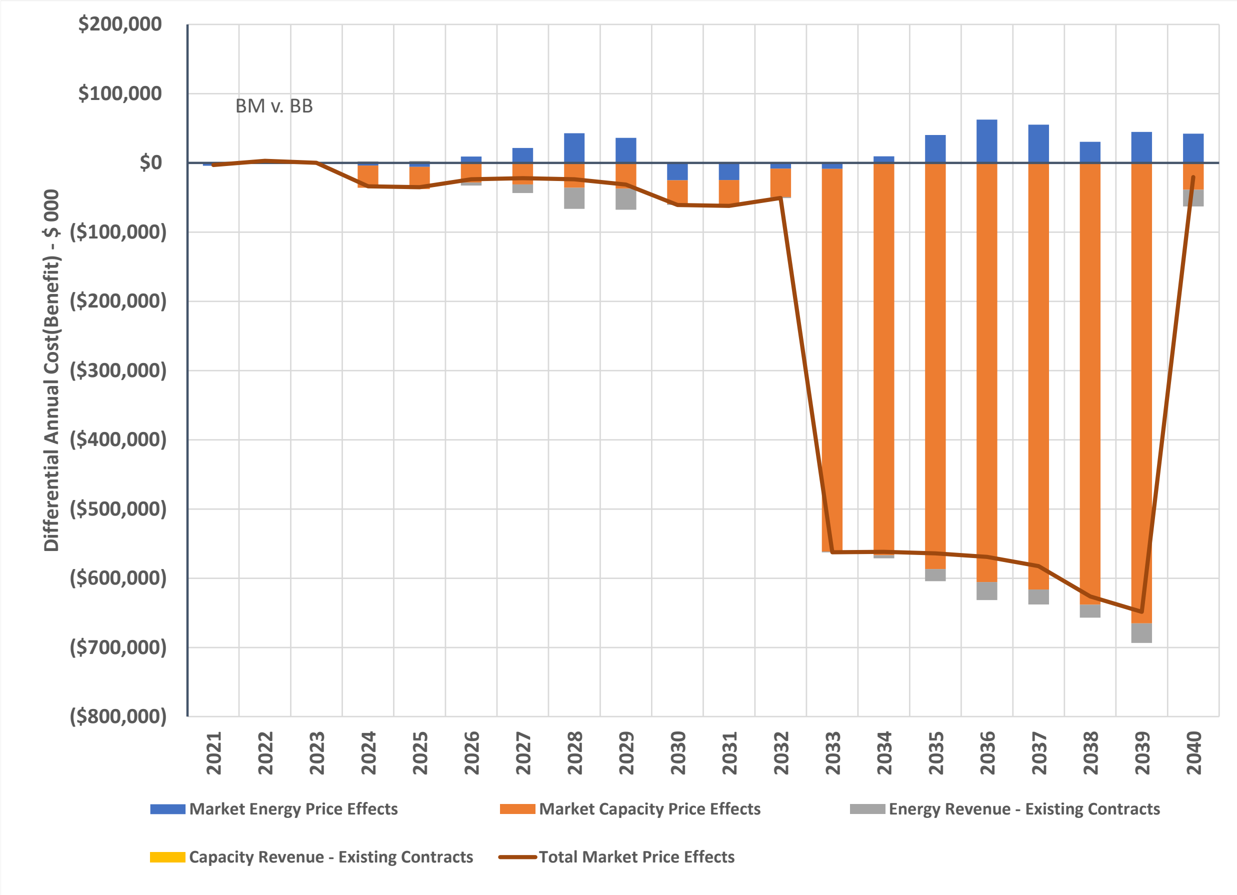
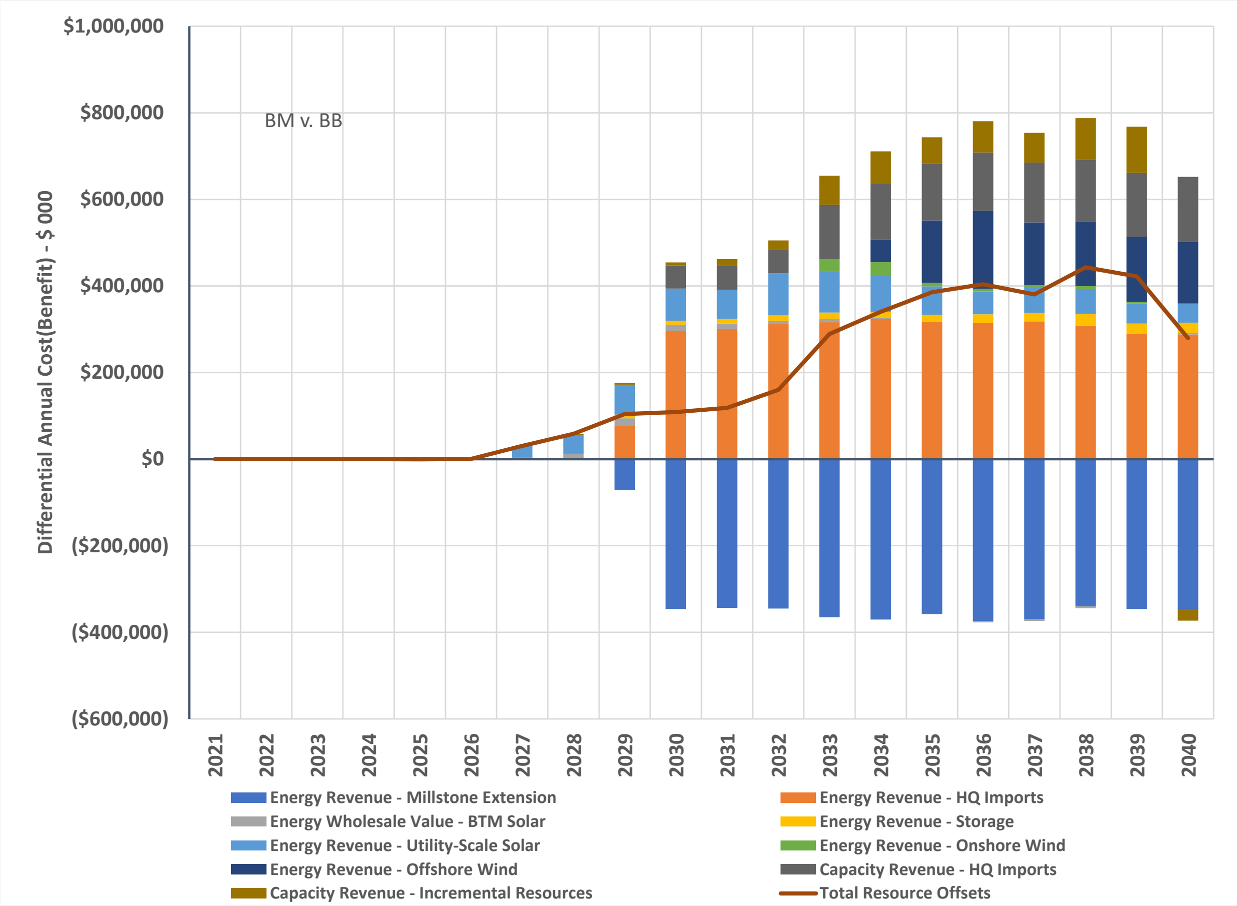


Figure 92 shows the direct revenue offsets for this scenario, relative to the Base Balanced Blend Scenario.

Figure 92: Market Revenue Offsets, Scenario BM

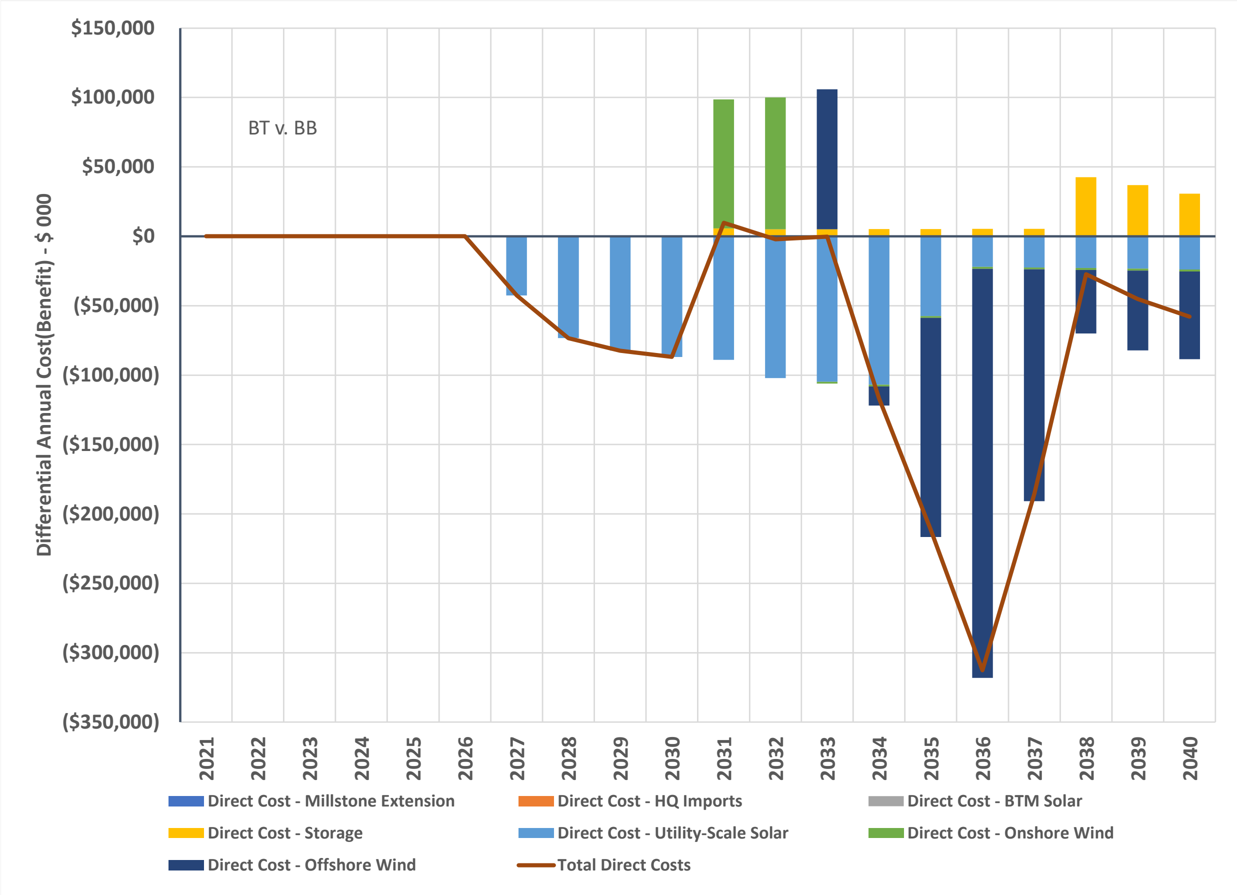


8.2.1.4 Transmission v. Balanced Blend (BT v. BB)

Details of the Base Transmission Scenario financial analysis are presented in an Excel workbook in Exhibit BT and in the charts presented below. The Excel exhibit includes annual nominal dollar and present value cost details as differentials between this scenario and both the Base Reference Scenario and the Base Balanced Blend Scenario. It also includes the charts for this scenario that appear in the main Report and in this appendix section.

Figure 93 shows the differential direct costs for the scenario against the direct costs of the Base Balanced Blend Scenario.

Figure 93: Direct Costs, Scenario BT



Market price effects of the scenario, relative to the Base Balanced Blend Scenario, are shown in Figure 94.

Figure 94: Market Price Effects, Scenario BT

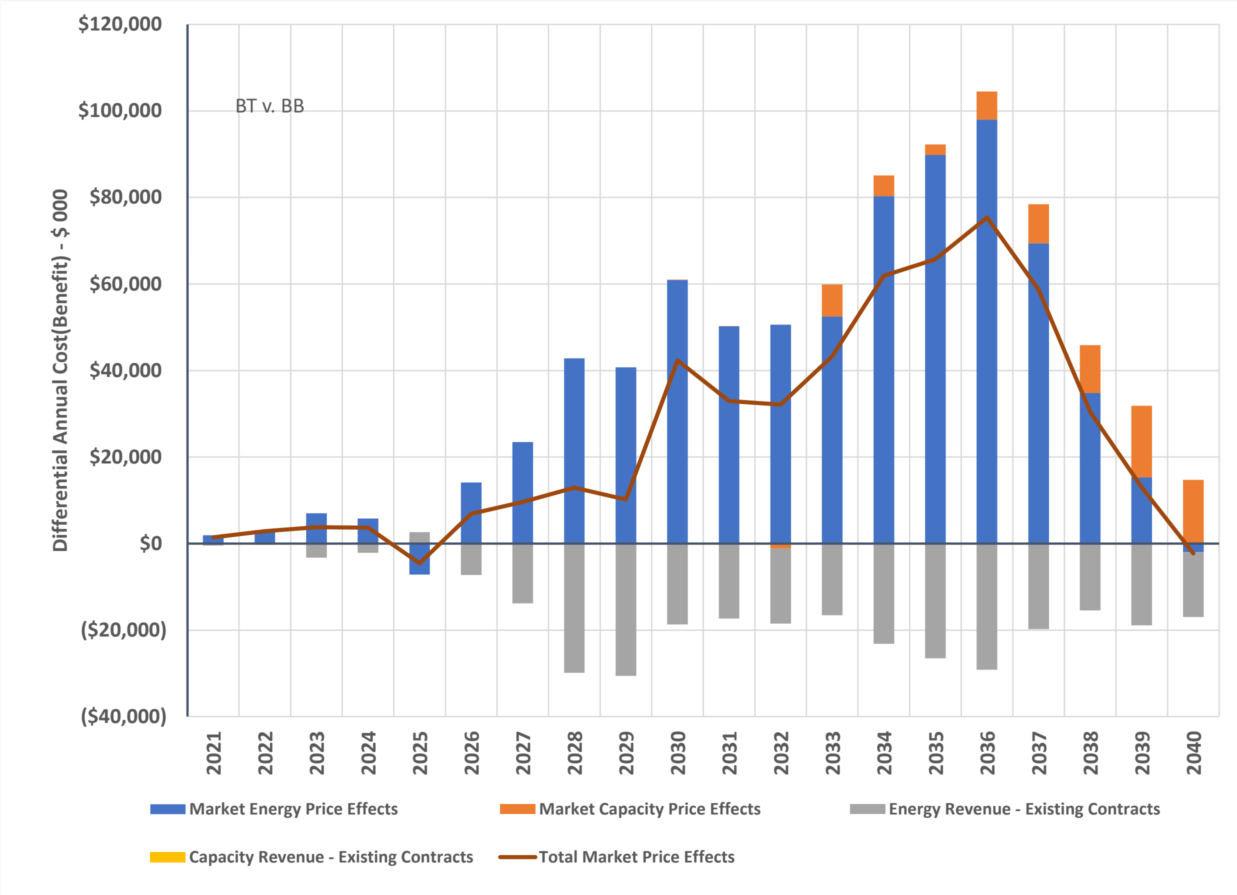
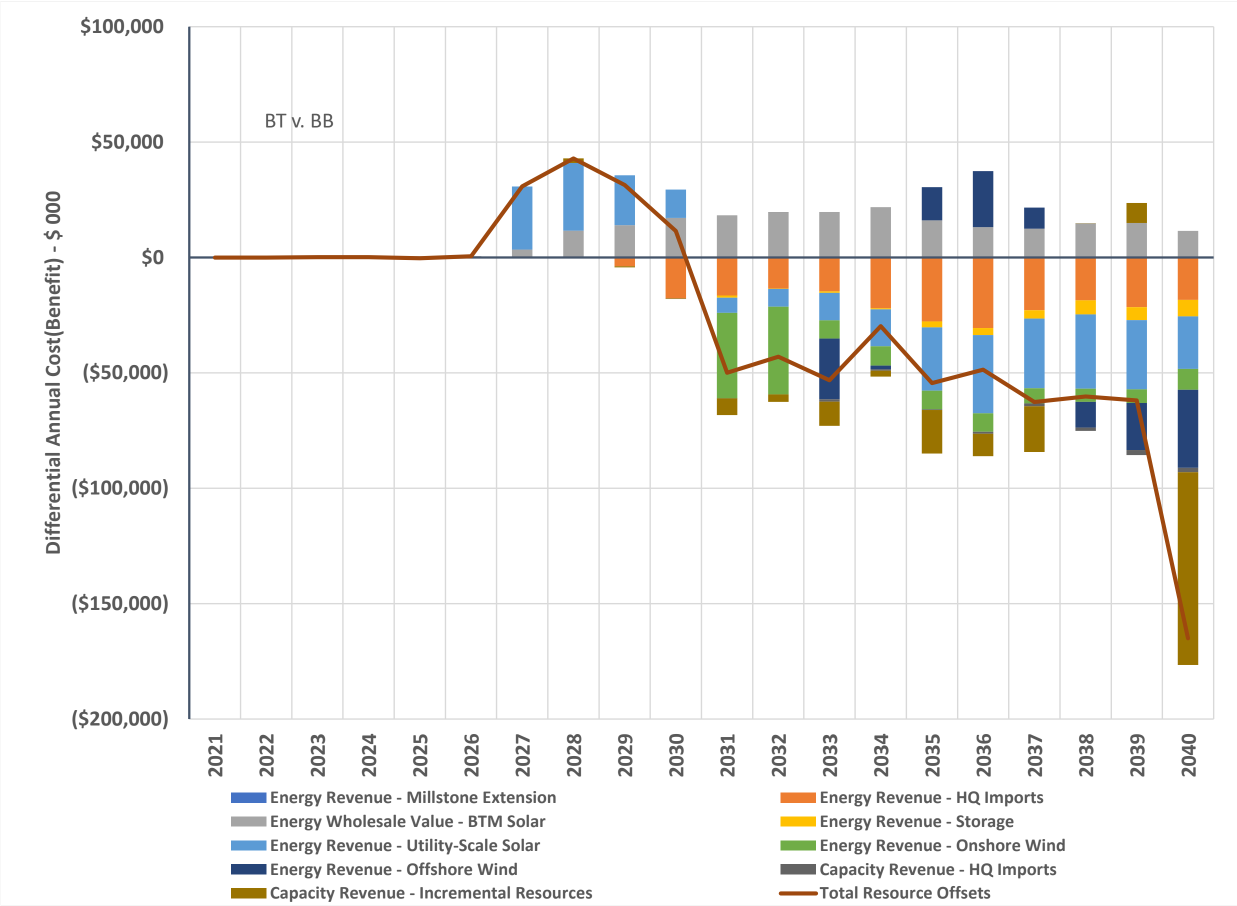


Figure 95 shows the direct revenue offsets for this scenario, relative to the Base Balanced Blend Scenario.

Figure 95: Market Revenue Offsets, Scenario BT



8.2.2 Electrification Load Case Scenarios

Cost and benefit results for the scenarios under the Electrification Load Case are presented in summary present value form in Table 32 below and in graphical detail in the subsections which follow. The costs and benefits are also provided in full detail in Excel file exhibits for each scenario.

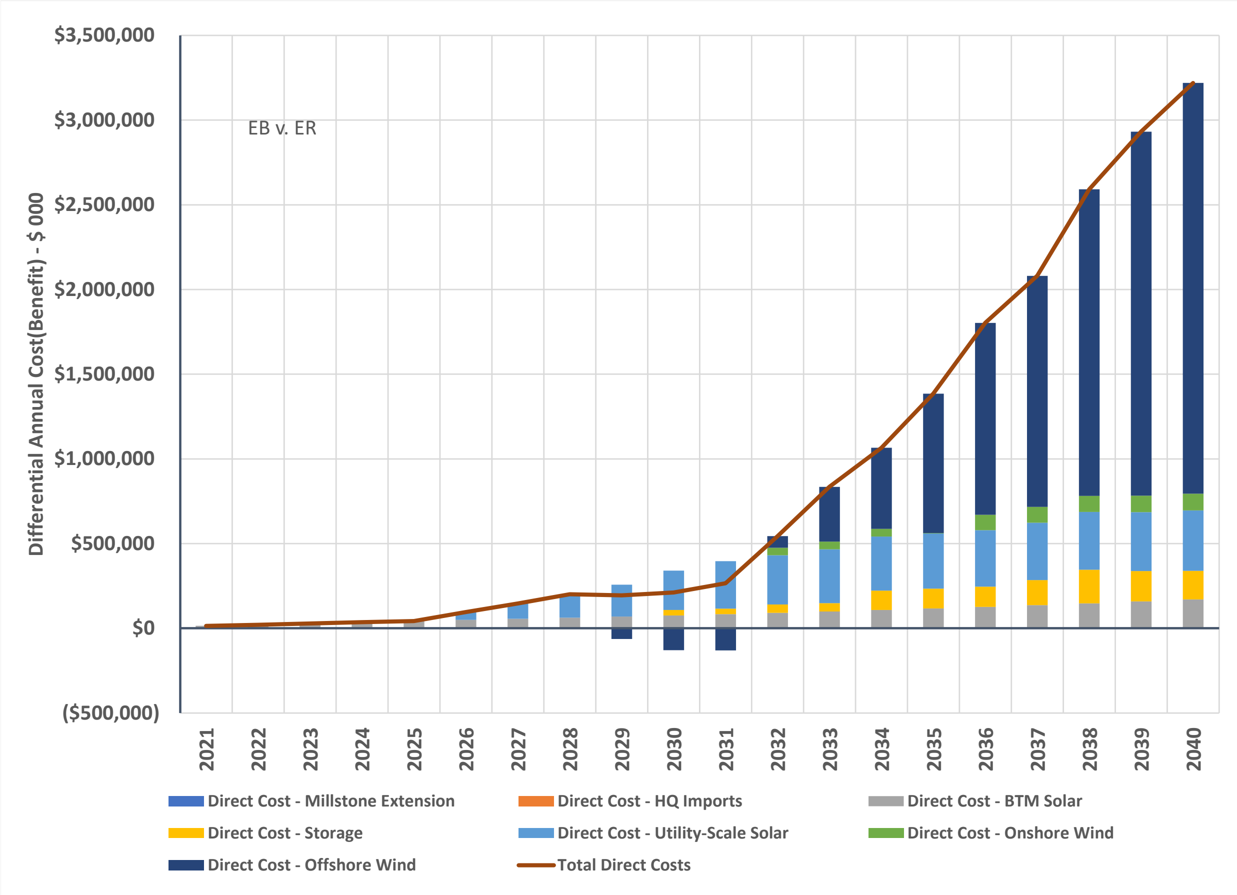
Table 32: Present Value Comparison of Electrification Case Scenarios

	Present Value of Differential Cost ($ MM)						
	Differentials v. ER				Differentials v. EB		
Cost Item or Category	**EB**	**ES**	**EM**	**ET**	**ES**	**EM**	**ET**
Market Energy Price Effects	($983)	($1,133)	($940)	($965)	($150)	$43	$19
Market Capacity Price Effects	$294	($396)	$114	$441	($690)	($180)	$148
Energy Revenue - Existing Contracts	$340	$341	$180	$239	$1	($161)	($101)
Capacity Revenue - Existing Contracts	$0	$0	$0	$0	$0	$0	$0
Direct Cost - Millstone Extension	$0	$0	$2,334	$0	$0	$2,334	$0
Energy Revenue - Millstone Extension	$0	$0	($1,442)	$0	$0	($1,442)	$0
Direct Cost - HQ Imports	$0	$0	($3,862)	$0	$0	($3,862)	$0
Energy Revenue - HQ Imports	$206	$181	$1,329	$157	($25)	$1,123	($49)
Capacity Revenue - HQ Imports	($45)	$36	$320	($86)	$80	$365	($41)
Direct Cost - BTM Solar	$716	$2,388	$716	$716	$1,672	$0	$0
Energy Wholesale Value - BTM Solar	($76)	$89	($27)	($5)	$165	$50	$71
Direct Cost - Storage	$400	$400	$68	$386	$0	($332)	($14)
Energy Revenue - Storage	($32)	($47)	($19)	($39)	($15)	$13	($7)
Direct Cost - Utility-Scale Solar	$1,535	$1,296	$638	$1,316	($239)	($897)	($218)
Energy Revenue - Utility-Scale Solar	($521)	($417)	($211)	($606)	$105	$310	($84)
Direct Cost - Onshore Wind	$198	$169	$68	$427	($29)	($130)	$229
Energy Revenue - Onshore Wind	($6)	($16)	$7	($96)	($10)	$13	($90)
Direct Cost - Offshore Wind	$3,058	$2,507	$187	$2,459	($551)	($2,871)	($599)
Energy Revenue - Offshore Wind	($282)	($235)	$48	($291)	$47	$330	($9)
Capacity Revenue - Incremental Resources	($403)	($237)	($134)	($407)	$166	$269	($4)
Societal Cost of Carbon Emissions	($699)	($704)	($828)	($647)	($5)	($129)	$52
Subtotals							
Millstone Extension Direct Cost	$0	$0	$2,334	$0	$0	$2,334	$0
Millstone Extension Market Value	$0	$0	($1,442)	$0	$0	($1,442)	$0
Wholesale Market Price Effects	($690)	($1,529)	($826)	($523)	($840)	($136)	$166
Revenue Effect on Existing Contracts	$340	$341	$180	$239	$1	($161)	($101)
Incremental Resource Direct Cost	$5,907	$6,760	($2,185)	$5,304	$854	($8,092)	($602)
Incremental Resource Market Value	($1,160)	($646)	$1,314	($1,374)	$514	$2,474	($214)
Societal Cost of GHG Effects	($699)	($704)	($828)	($647)	($5)	($129)	$52
Total Societal Cost	$3,698	$4,222	($1,453)	$2,999	$524	($5,151)	($699)
Total Ratepayer Cost	$4,397	$4,926	($625)	$3,646	$529	($5,022)	($752)

8.2.2.1 Balanced Blend v. Reference (EB v. ER)

The annual costs and benefits for the Electrification Balanced Blend Scenario are presented as differentials relative to the Electrification Reference Scenario in three charts grouping items into major categories. Figure 96 shows the direct costs for all added Connecticut-procured zero-carbon resources added under the scenario, including the HQ Import line, more Connecticut solar BTM PV resources than included in the Electrification Reference Scenario, and the Connecticut share of incremental resources selected in the Aurora simulation and optimization process relative to the Electrification Reference Scenario selections.

Figure 96: Direct Costs, Scenario EB



Market price effect details are charted by year in Figure 97.

Figure 97: Market Price Effects, Scenario EB

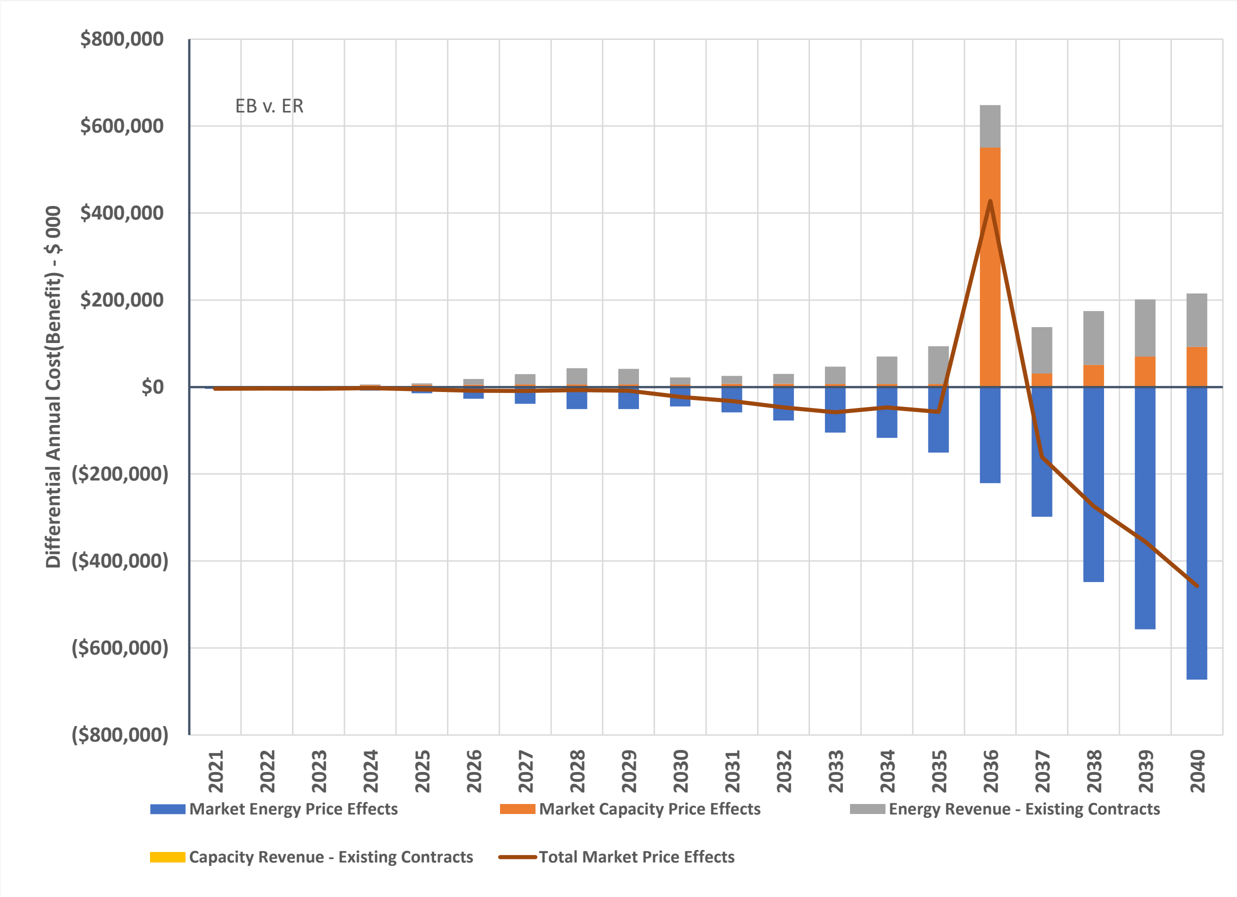
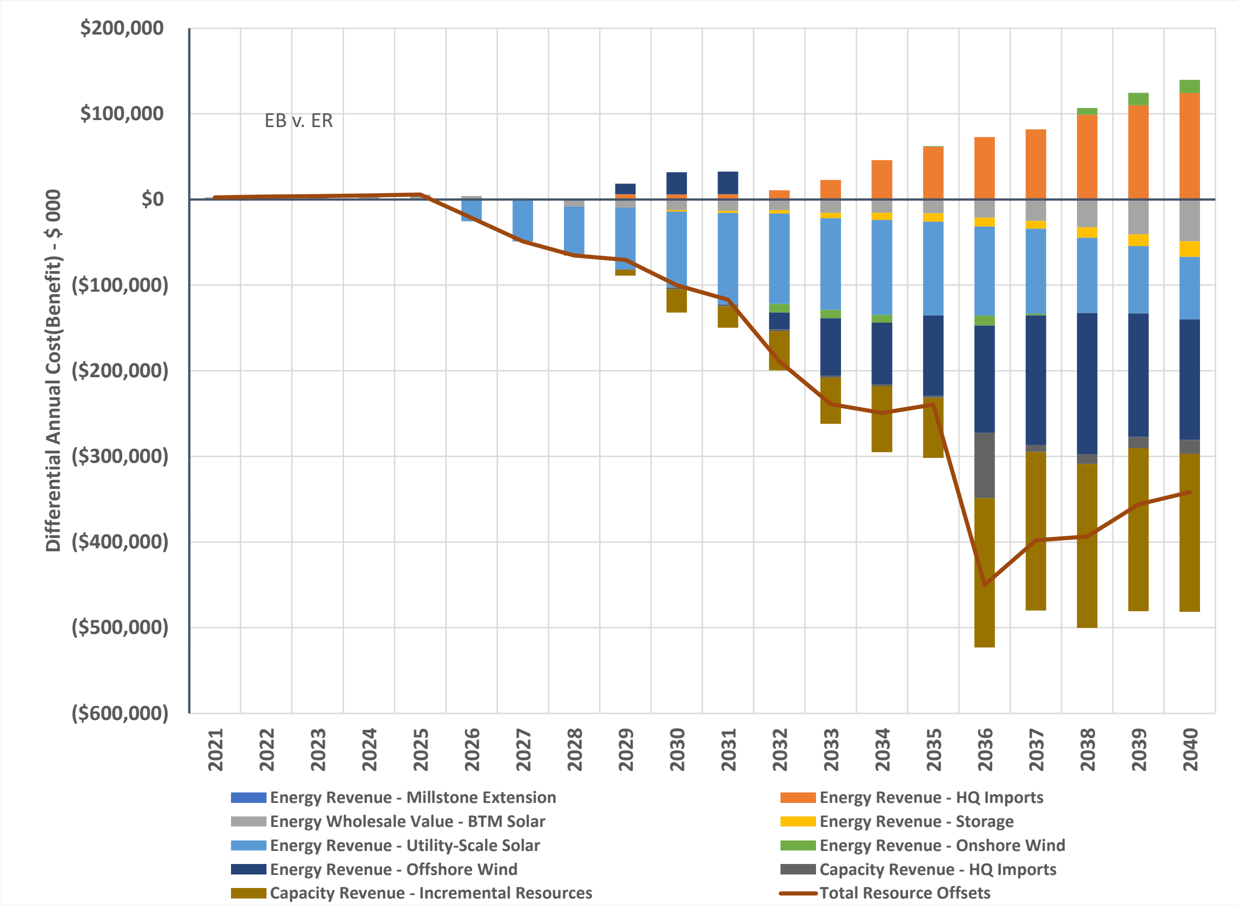


Figure 98 shows the direct cost offsets in the form of energy and capacity payments from the various added zero-carbon resources under the scenario.

Figure 98: Market Revenue Offsets, Scenario EB

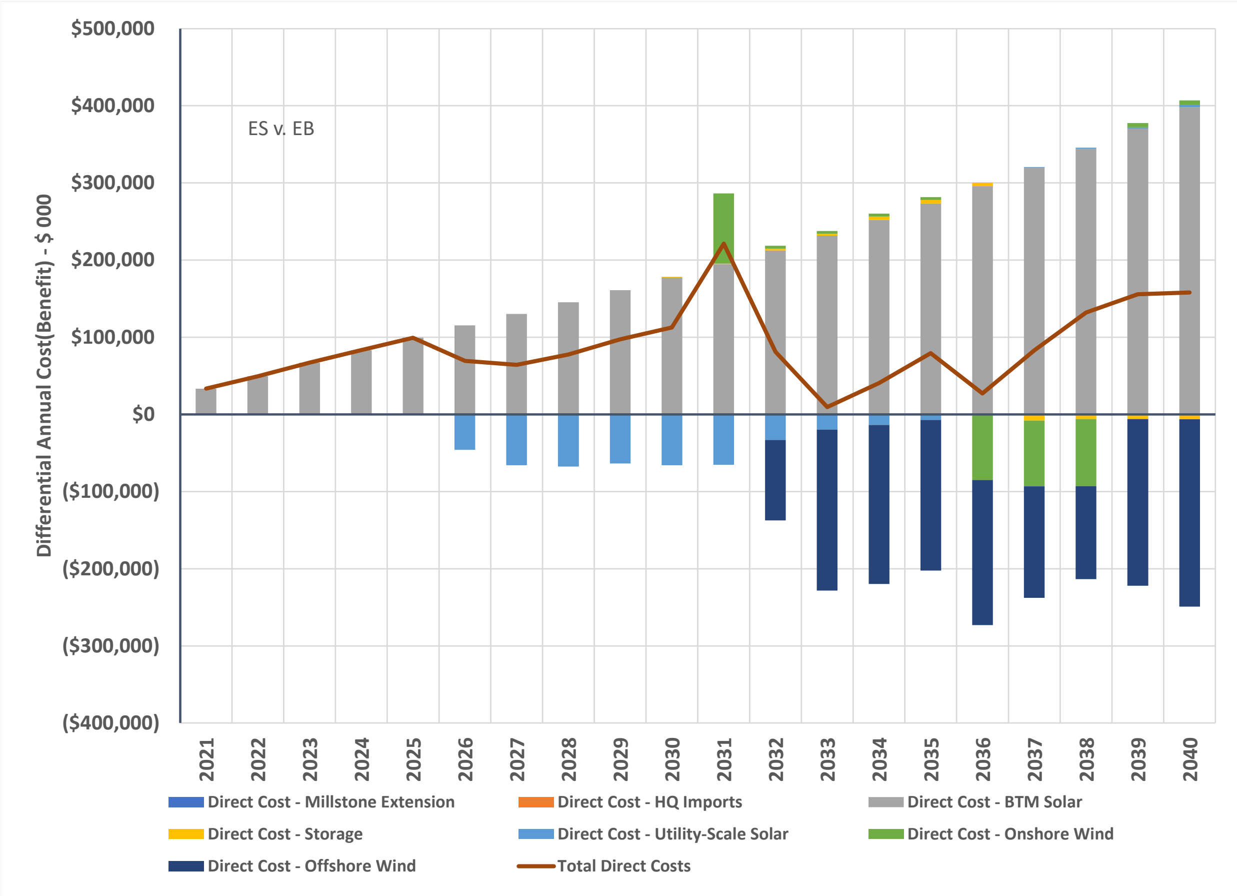


8.2.2.2 Solar BTM PV Emphasis v. Balanced Blend (ES v EB)

Details of the Electrification Solar BTM PV Emphasis Scenario financial analysis are presented in Excel form in Exhibit ES and in the charts presented below. The Excel exhibit includes annual nominal dollar and present value cost details as differentials between this scenario and both the Electrification Reference Scenario and the Electrification Balanced Blend Scenario. It also includes the charts for this scenario that appear in the main Report and in this appendix section.

Figure 99 shows the differential direct costs for the scenario against the direct costs of the Base Balanced Blend Scenario.

Figure 99: Direct Costs, Scenario ES



Market price effects of the scenario, relative to the Base Balanced Blend Scenario, are shown in Figure 100.

Figure 100: Market Price Effects, Scenario ES

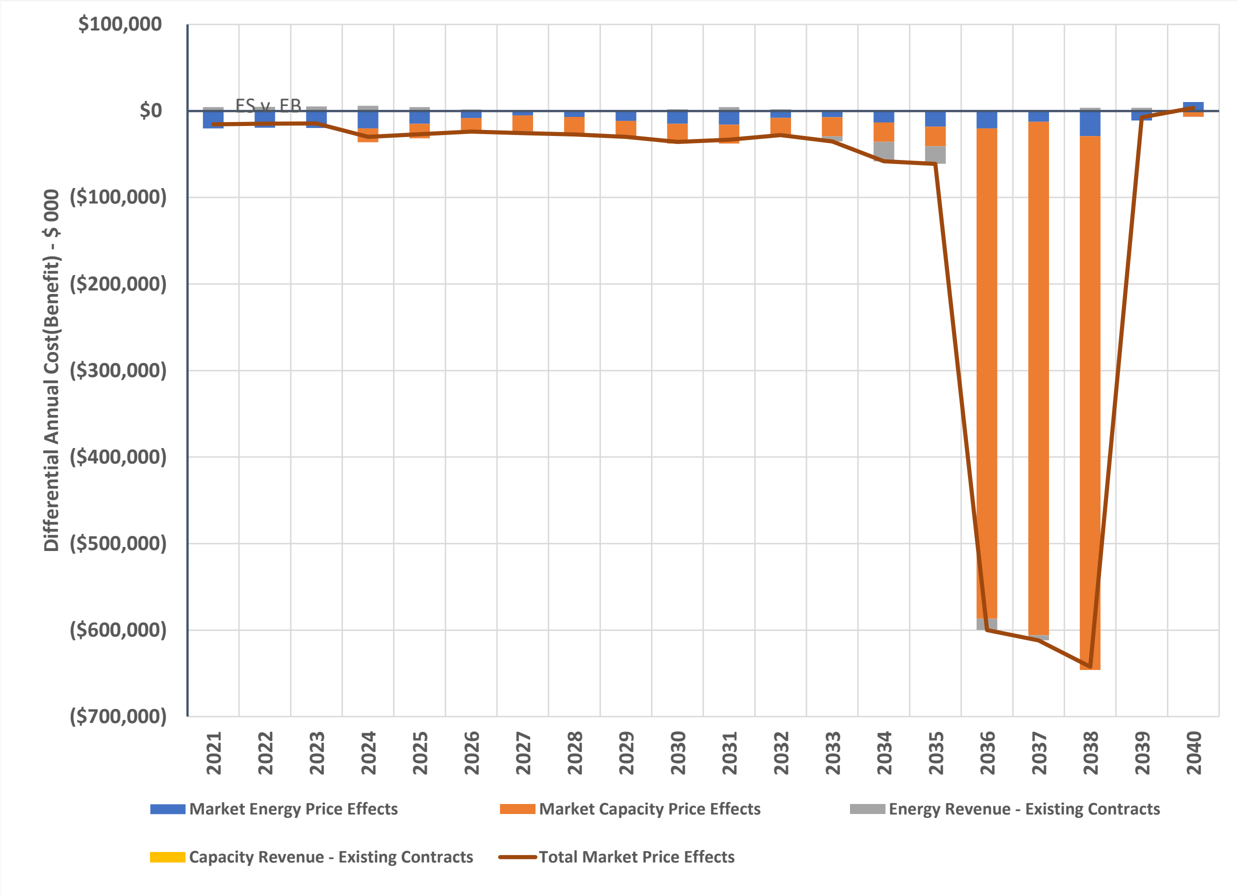
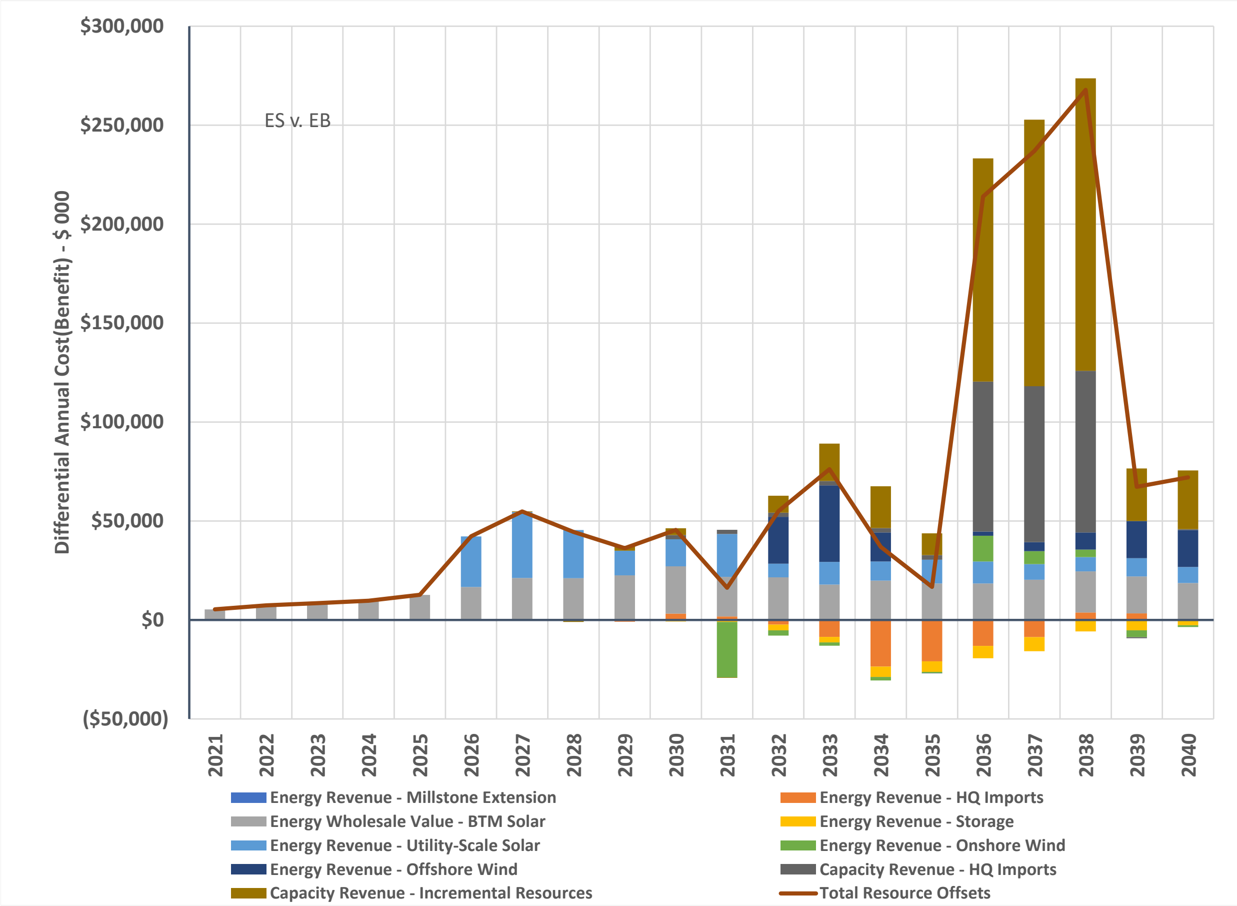


Figure 101 shows the direct revenue offsets for this scenario, relative to the Base Balanced Blend Scenario.

Figure 101: Market Revenue Offsets, Scenario ES

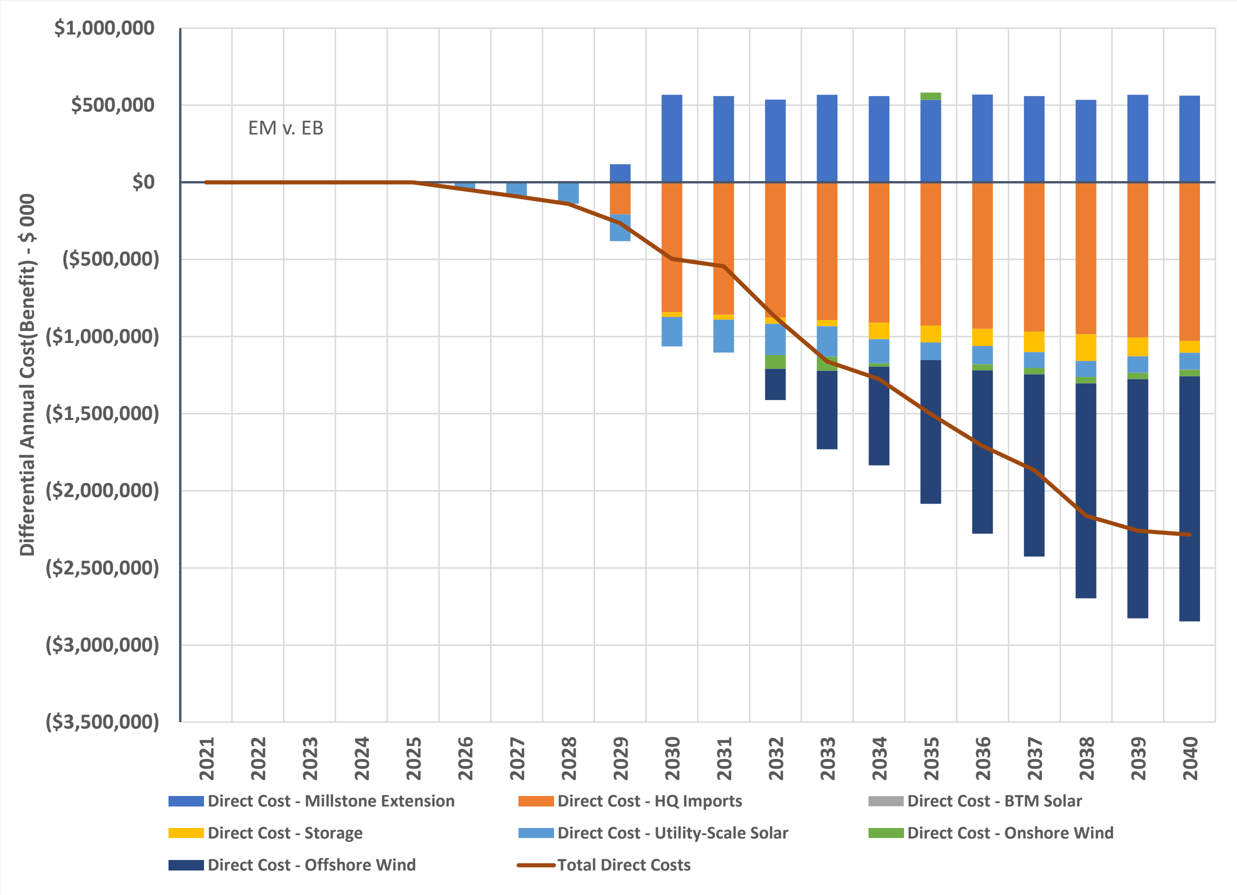


8.2.2.3 Millstone Extension v. Balanced Blend (EM v. EB)

Details of the Electrification Millstone Extension Scenario financial analysis are presented in Excel form in Exhibit EM and in the charts presented below. The Excel exhibit includes annual nominal dollar and present value cost details as differentials between this scenario and both the Electrification Reference Scenario and the Electrification Balanced Blend Scenario. It also includes the charts for this scenario that appear in the main Report and in this appendix section.

Figure 102 shows the differential direct costs for the Electrification Millstone Extension Scenario against the direct costs of the Electrification Balanced Blend Scenario.

Figure 102: Direct Costs, Scenario EM



Market price effects of the scenario, relative to the Base Balanced Blend Scenario, are shown in Figure 103.

Figure 103: Market Price Effects, Scenario EM

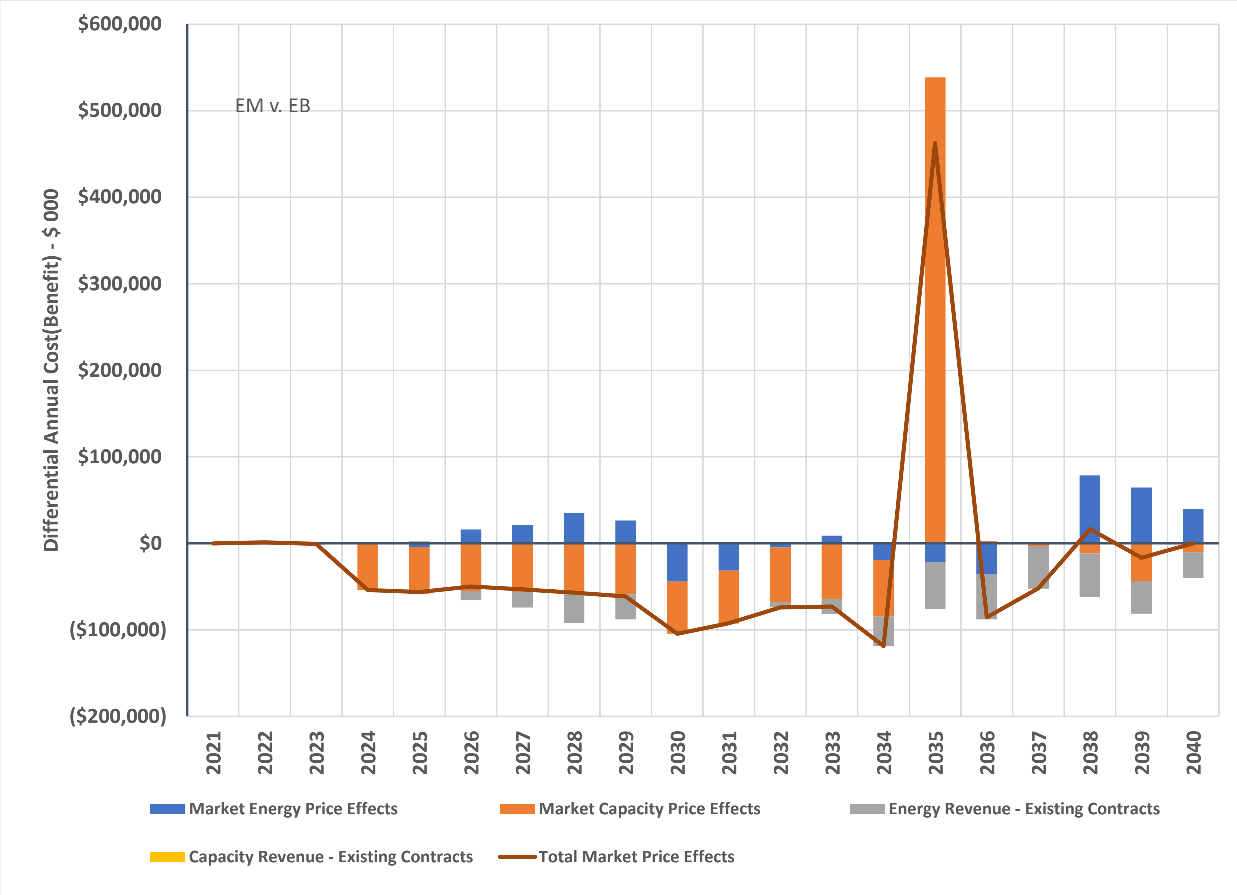
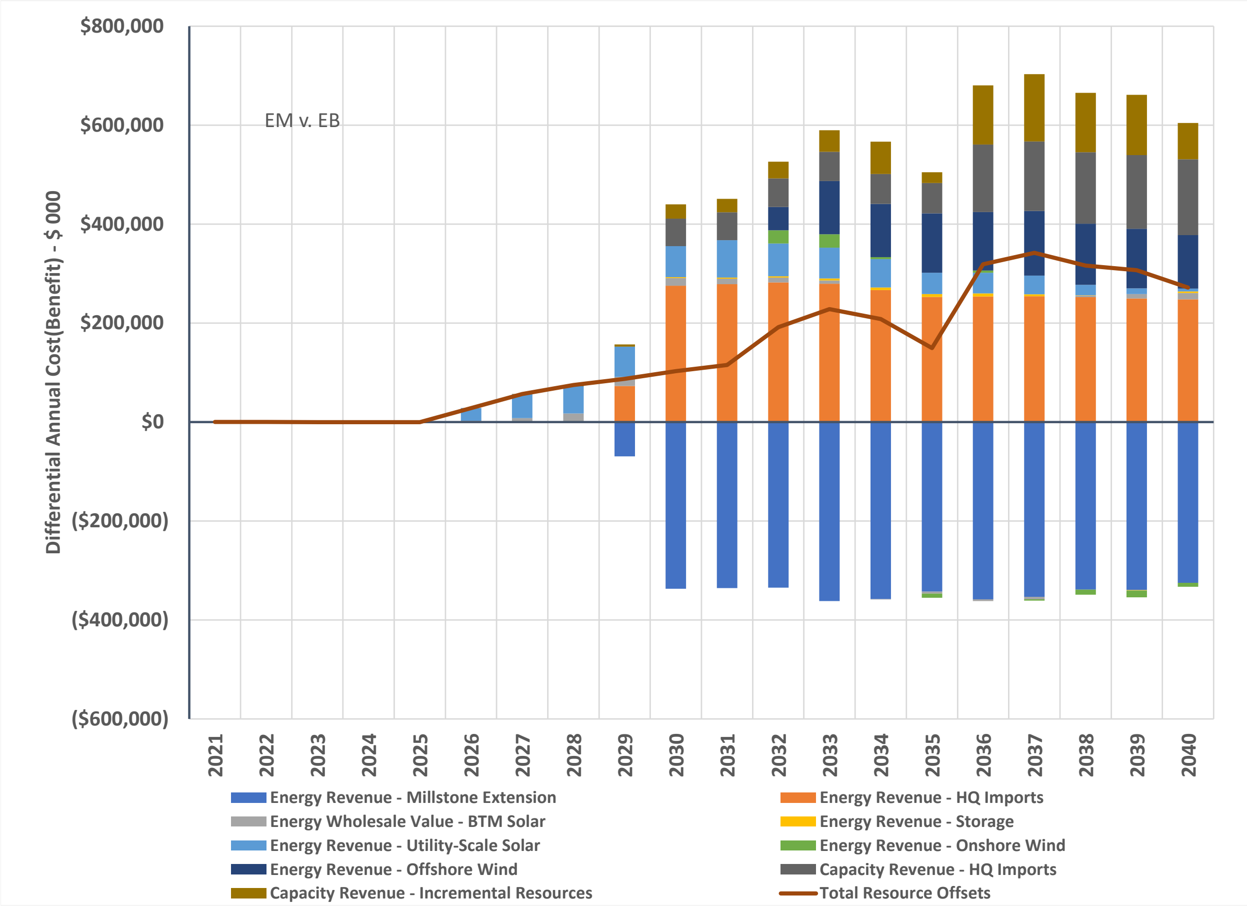


Figure 104 shows the direct revenue offsets for this scenario, relative to the Base Balanced Blend Scenario.

Figure 104: Market Revenue Offsets, Scenario EM

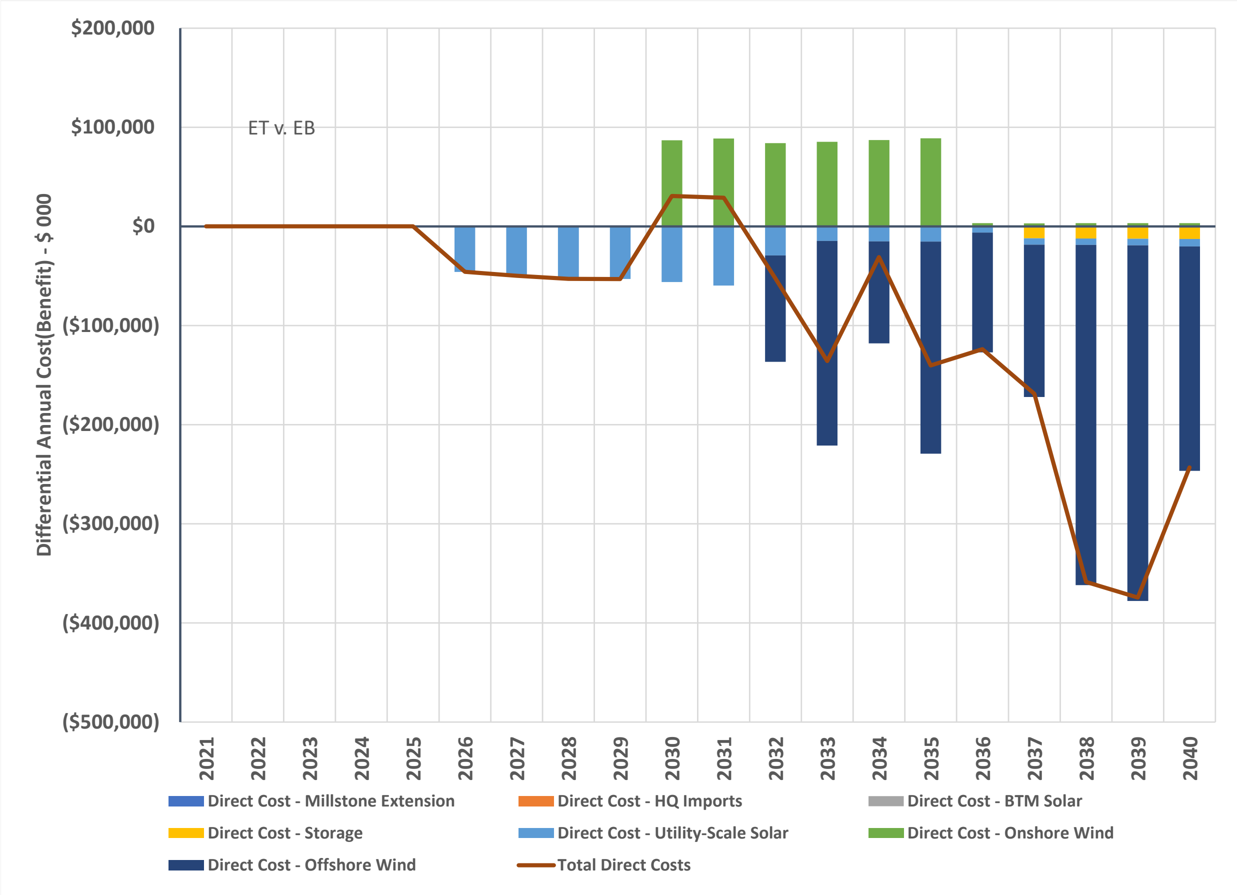


8.2.2.4 Transmission v. Balanced Blend (ET v. EB)

Details of the Electrification Transmission Scenario financial analysis are presented in Excel form in Exhibit ET and in the charts presented below. The Excel exhibit includes annual nominal dollar and present value cost details as differentials between this scenario and both the Electrification Reference Scenario and the Electrification Balanced Blend Scenario. It also includes the charts for this scenario that appear in the main Report and in this appendix section.

Figure 105 shows the differential direct costs for the scenario against the direct costs of the Base Balanced Blend Scenario.

Figure 105: Direct Costs, Scenario ET



Market price effects of the scenario, relative to the Base Balanced Blend Scenario, are shown in Figure 106.

Figure 106: Market Price Effects, Scenario ET

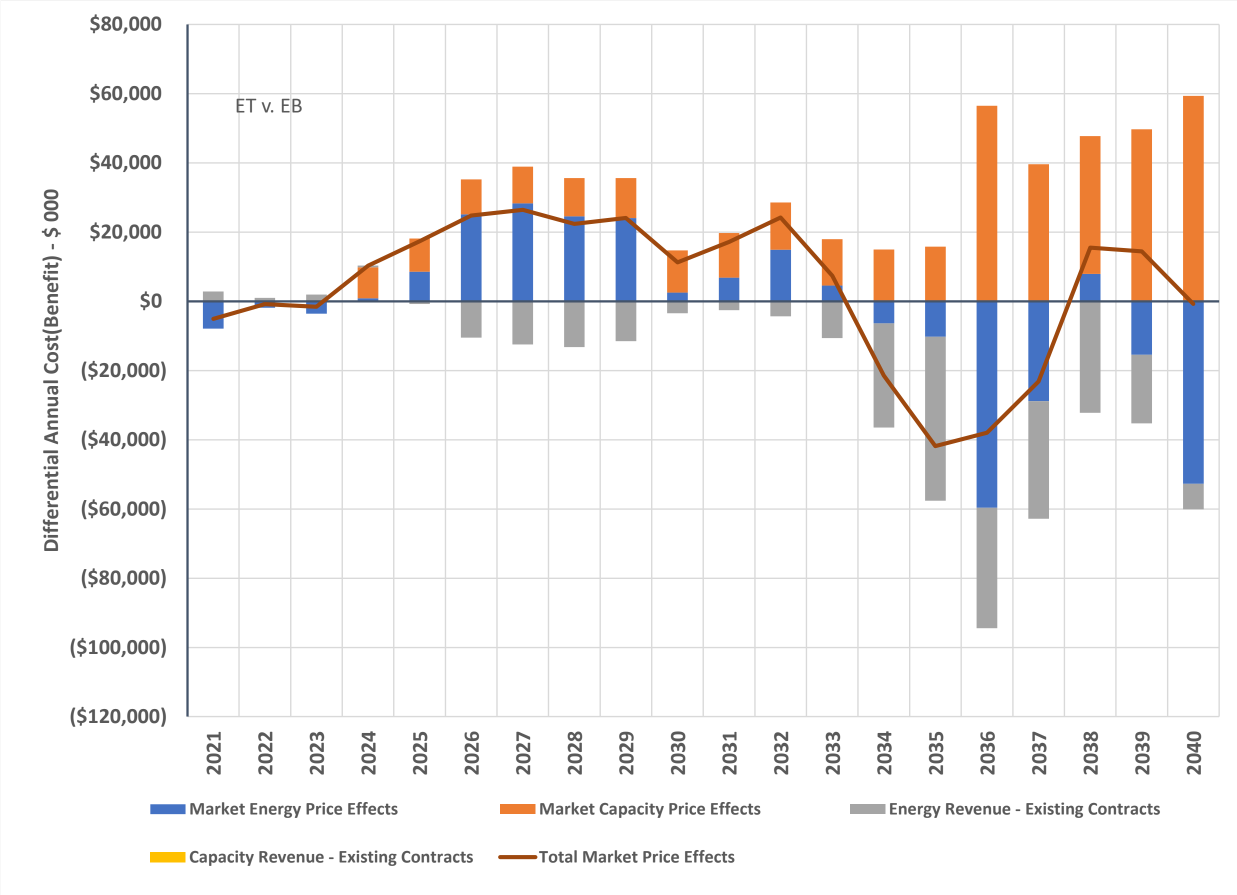
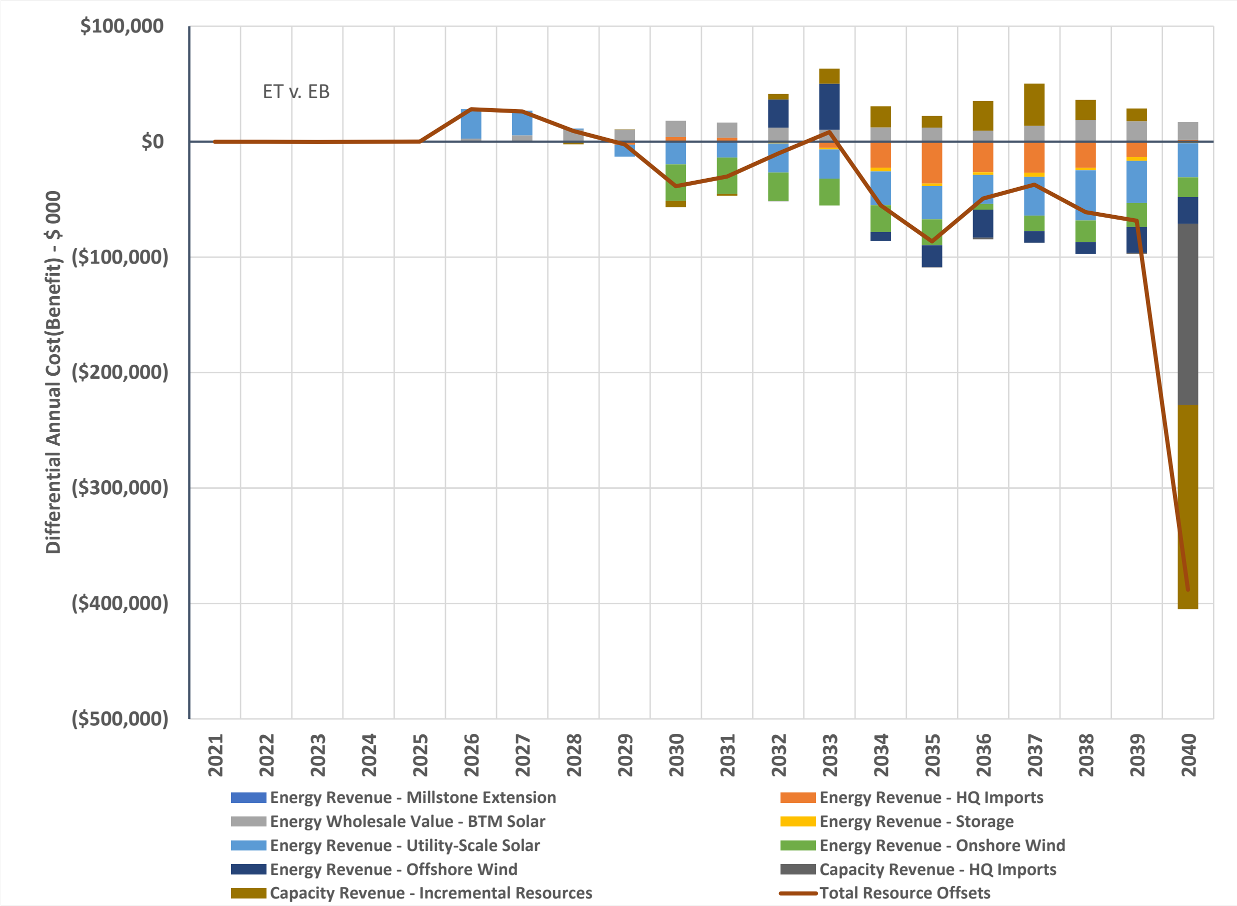


Figure 107 shows the direct revenue offsets for this scenario, relative to the Base Balanced Blend Scenario.

Figure 107: Market Revenue Offsets, Scenario ET



9 Hourly Emissions

Financial analysis allocated regional clean energy additions from Aurora to Connecticut by vintage year based on an annual carbon balance. Hourly data from the Base Balanced Blend and Base Millstone Extension scenarios were reviewed to investigate the degree to which clean energy, demand, and CO_2 emissions within Connecticut were balanced at the hourly level.

Demand and clean energy were compared for 2040, as the last studied year has the full clean energy build needed to balance supply and demand at the annual time step. Box and whiskers charts showing the same distribution statistics as in Section 7 are used. Hourly demand in 2040 for Connecticut is identical for the two Base load scenarios (Figure 108). Hourly clean energy supply for the two scenarios are similar on average, but the Base Balanced Blend scenario (Figure 109) has more dispersion than the Base Millstone Extension scenario (Figure 110).

Figure 108: 2040 Hourly Demand by Month, Base Load Case

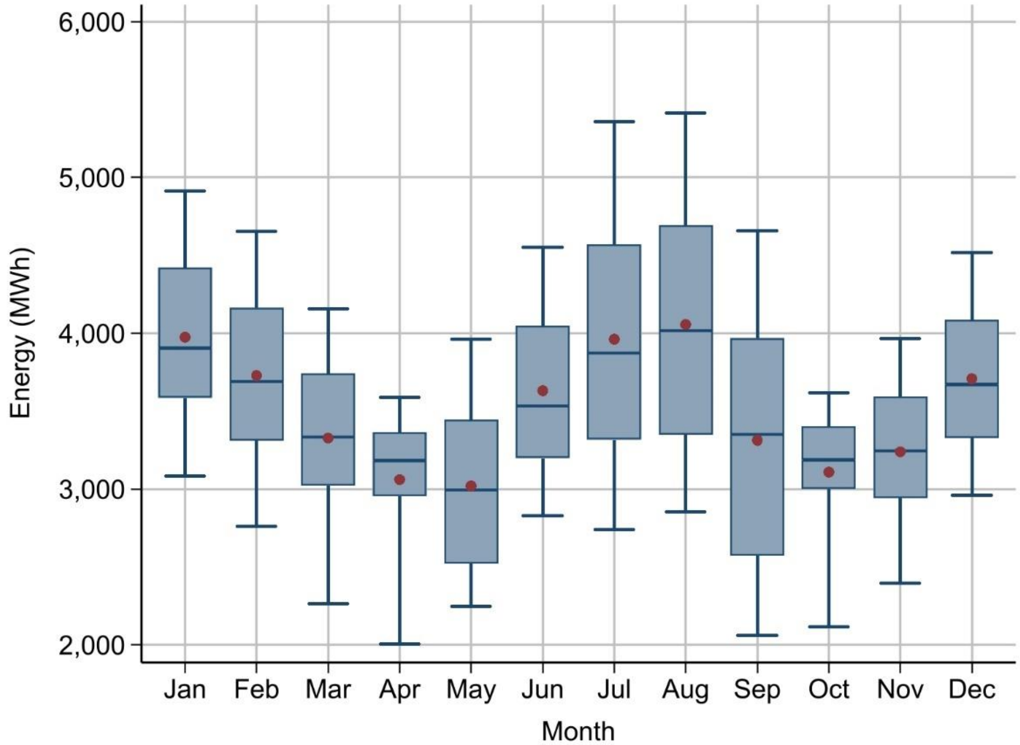


Figure 109: Hourly Clean Energy Generation by Month, Base Balanced Blend Scenario

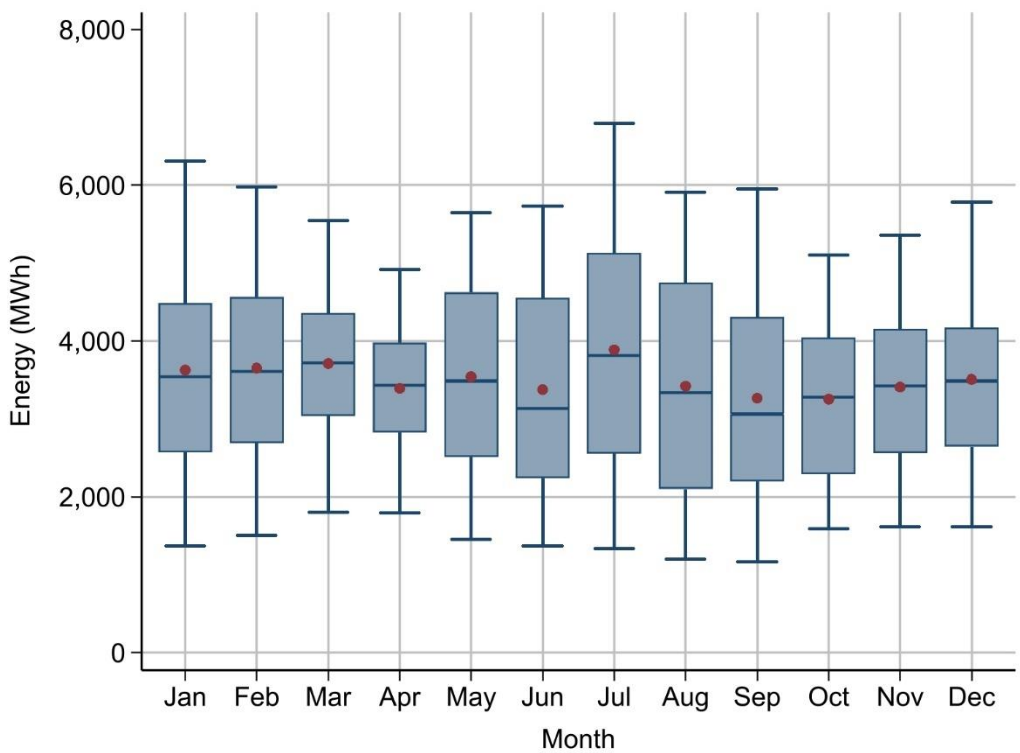
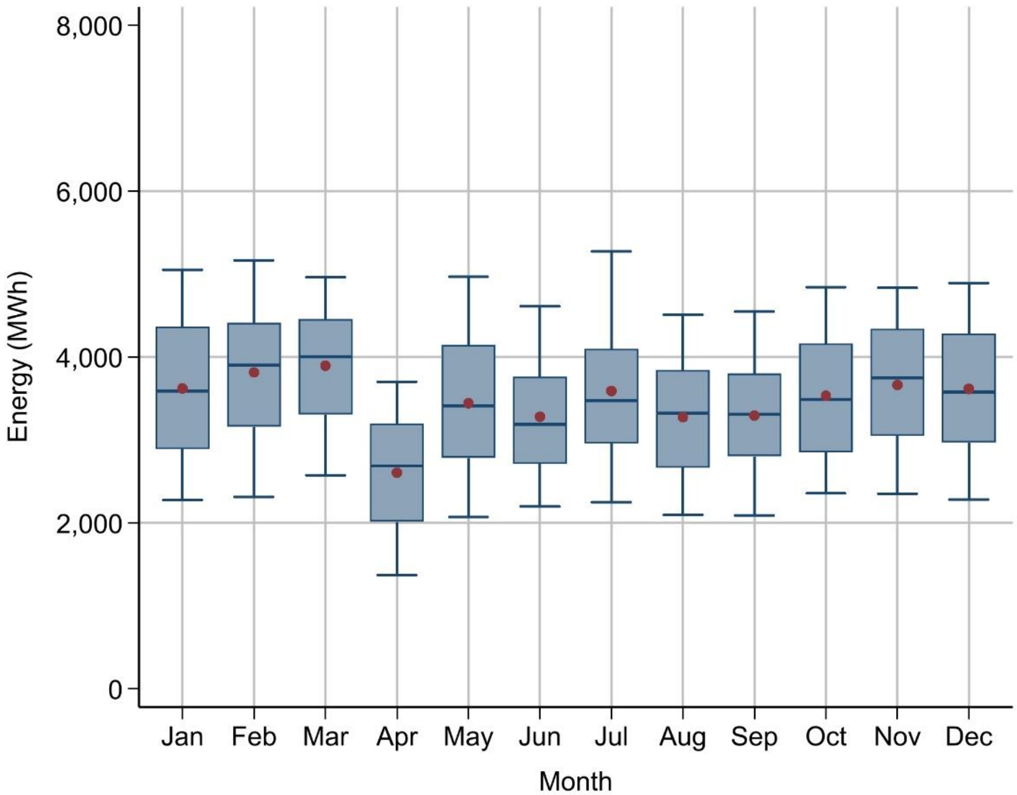


Figure 110: Hourly Clean Energy Generation by Month, Base Millstone Extension Scenario



The monthly P95 energy demands (top of the upper whisker) in Figure 108 are significantly lower than the P95 clean energy generation in Figure 109 and Figure 110. The large drop in April for the Millstone Extension scenario (Figure 110Figure 108) represents the refueling period for Millstone unit 3. Other months have similar clean energy generation averages, but the hourly dispersion of clean energy generation is significantly tighter in the Millstone Extension case, due to the nuclear facility's all-hours generation at full capability. This relationship is echoed in the clean energy balance, the difference between Connecticut energy generation and demand. For each scenario, the P95 balance shortfalls are at least 2,000 MWh in several months. Shortfalls are most acute in the summer months, but winter has similar P5 balance shortfalls.

Visualizing the balances by hour of day shows that shortfalls are greatest during late evening, when demand is near peak and solar energy is unavailable. Hourly demand is net of BTM PV, hence the delayed peak in HE20 (Figure 113). The Base Balanced Blend scenario (Figure 114) has more hours with a clean energy balance shortfall than the Base Millstone Extension scenario (Figure 115:).

Figure 111: Hourly Clean Energy Balance by Month, Base Balanced Blend Scenario

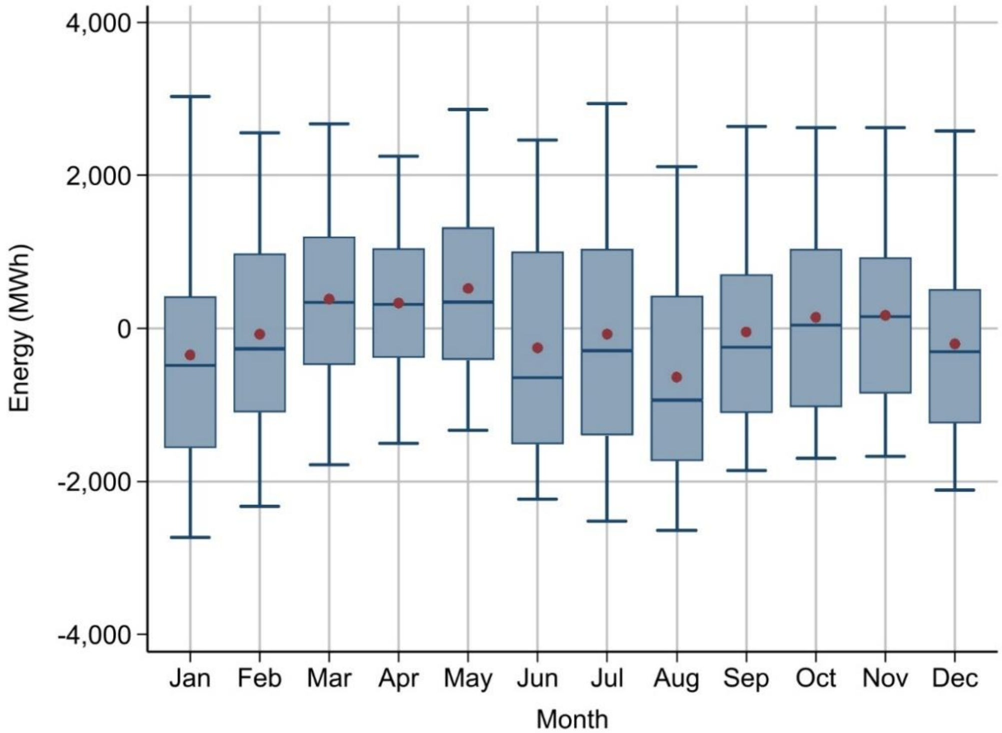


Figure 112: Hourly Clean Energy Balance by Month, Base Millstone Extension Scenario

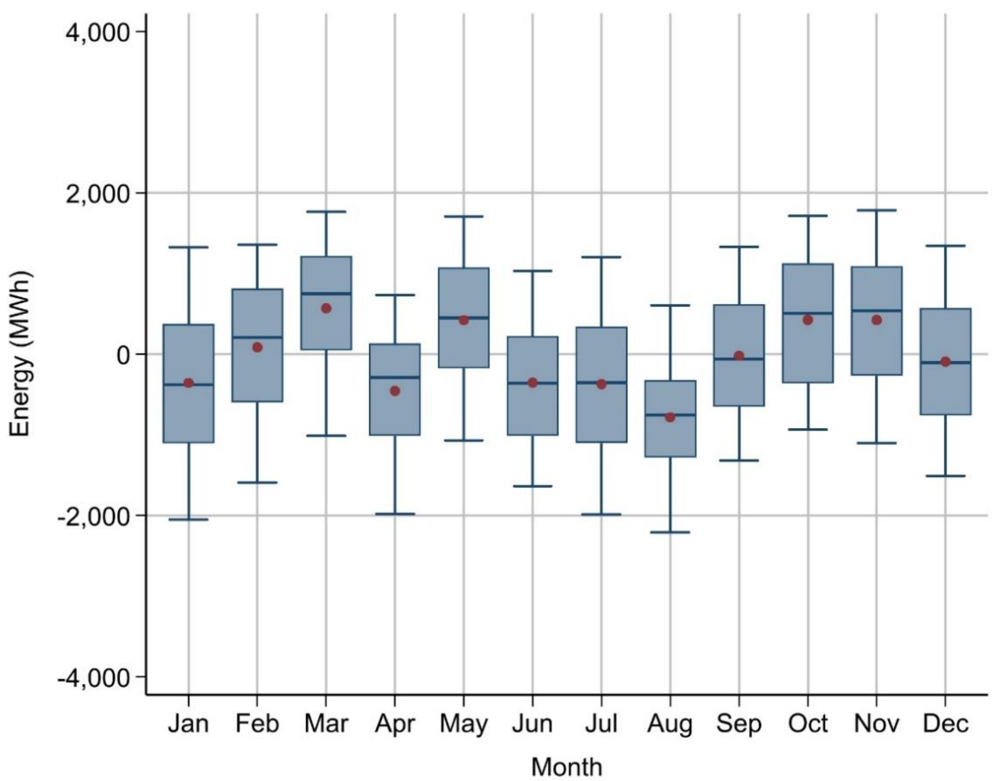


Figure 113: 2040 Hourly Demand by Hour of Day, Base Load Case

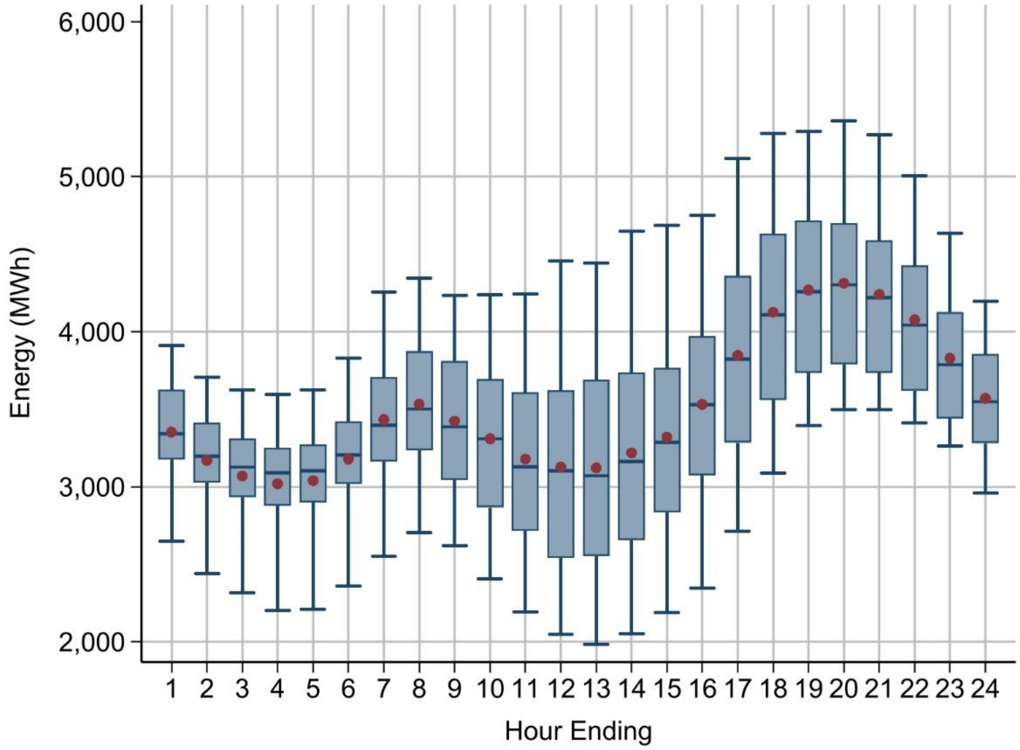


Figure 114: Hourly Clean Energy Balance by Hour of Day, Base Balanced Blend Scenario

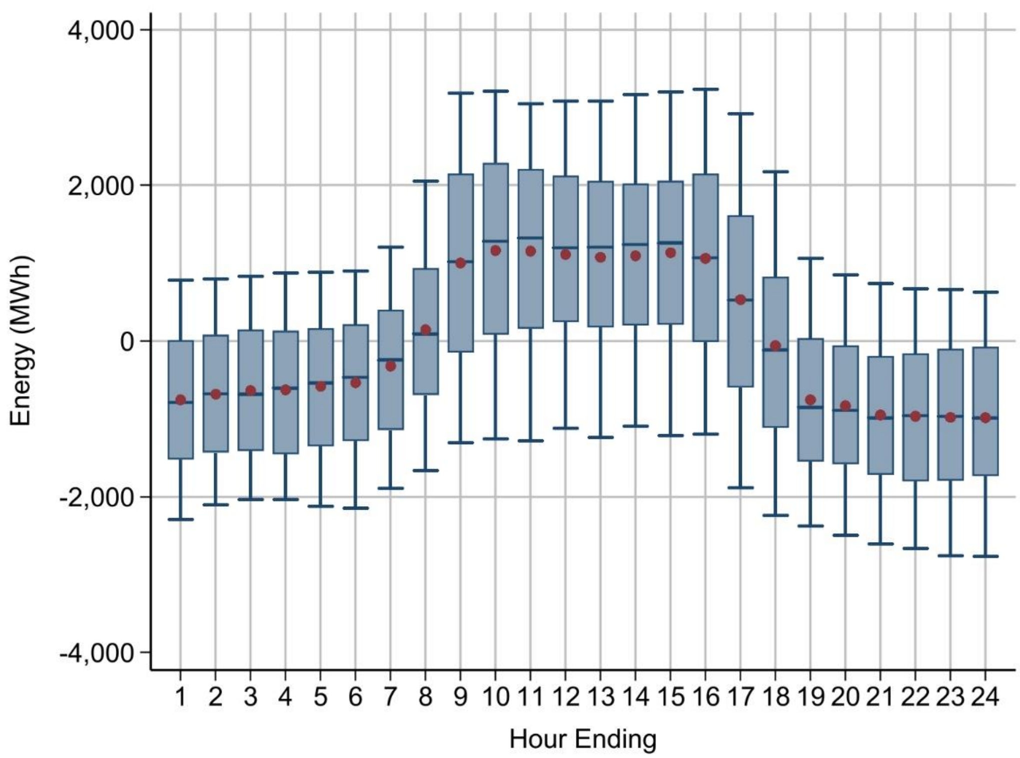
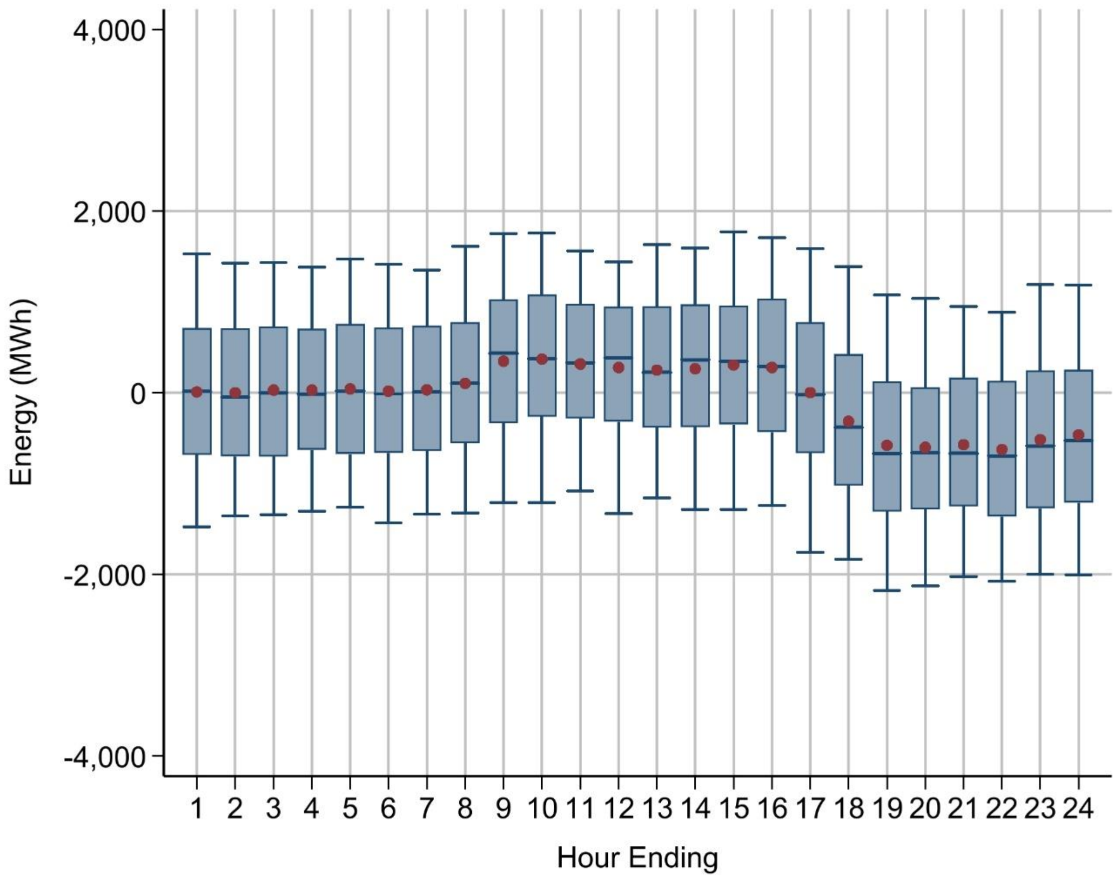


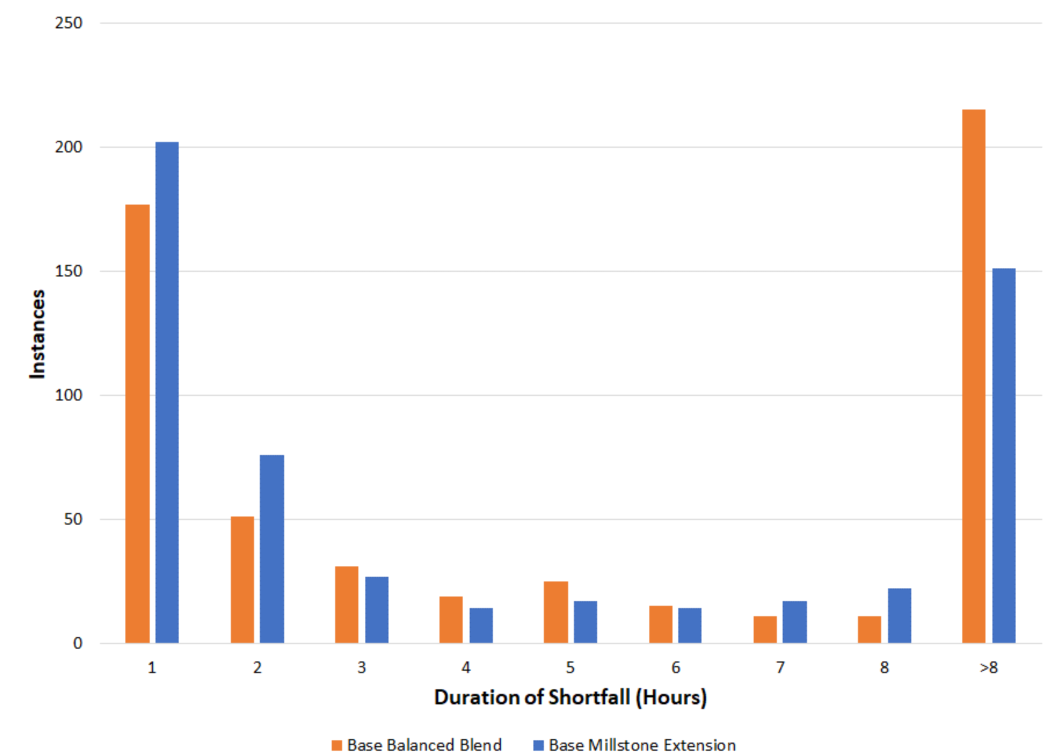
Figure 115: Hourly Clean Energy Balance by Hour of Day, Millstone Extension Scenario



115

The clean energy balance whiskers shown above represent the distribution from the 5th to the 95th percentiles of each hour's balance. The maximum shortfalls in the Base Balanced Blend and Base Millstone Extension scenarios are 4,003 MWh and 3,477 MWh, respectively. It is difficult to identify any path to completely balance Connecticut's hourly clean energy supply and demand given the candidate resource options considered (VERs, hydro imports, and battery storage), let alone do so economically. Storage alone is not a viable path, as both scenarios reviewed experience shortfalls that extend several days, with no surplus energy to store. A large portion of clean energy shortfalls extend more than eight hours (Figure 116), which is the longest storage duration typically contemplated for battery projects, and the pumped storage capability at Northfield Mountain. HVDC ties provide firm energy, but it is unclear whether HQ can support several additional export projects beyond NECEC, the long-awaited Champlain-Hudson line into New York City, and the generic tie project utilized in policy cases without Millstone contract extension.

Figure 116: Frequency and Duration of Clean Energy Shortfalls, 2040



Some additional potential mitigation options may help better balance Connecticut's contracted clean energy generation and demand, such as:

- Active demand response, which could reduce system peaks that are often underserved by VERs
- Hydrogen or biofuels, which could allow for clean repowering of conventional and dispatchable generation
- Increased coordination with neighboring regions to better source and sink clean energy, capture geographic diversity of VER output

This review also only considered a typical weather year. Connecticut would have to consider whether hourly balancing could be met under abnormal short-term weather conditions or a poor year for VERs.[12] Other interim measures could be adopted to incent clean energy resources that can deliver energy during shortfall hours, similar to Massachusetts' Clean Peak Standard.

[12] Annual generation for wind power generation can vary by more than 20%. See Y.H. Wan, "Long-Term Wind Power Variability". NREL technical report, January 2012. https://www.nrel.gov/docs/fy12osti/53637.pdf