CONFIDENTIAL

VERMONT LMP FORECAST FOR THE 2019 IRP

OCTOBER 2018

PREPARED FOR
Vermont Electric Cooperative

PREPARED BY
Daymark Energy Advisors

DAYMARK ENERGY ADVISORS
370 MAIN STREET, SUITE 325 | WORCESTER, MA 01608
TEL: (617) 778-5515 | DAYMARKEA.COM

TABLE OF CONTENTS

I. Executive Summary 2
II. Model Overview 4
III. System Topology 5
IV. Key Inputs 8
A. Load 8
B. Fuel Prices 10
C. Emission Prices 14
D. Retirements and Thermal Capacity Additions 16
E. Renewable Additions 17
V. Results 20

TABLE OF FIGURES

Figure I-1: Vermont Zonal Prices for Reference, High, and Low Cases 3
Figure III-1: NMM Topology: ISO New England and regional interconnections 5
Figure IV-1: New England Coincident Peak Demand, Gross, Net of Passive Demand Response (PDR), and Behind-the-Meter Solar (BTM) 9
Figure IV-2: New England Energy Load, Gross Net of Passive Demand Response (PDR), and Behind-the-Meter Solar (BTM) 9
Figure IV-3: Henry Hub Gas Price Assumptions (2018$/MMBtu) 11
Figure IV-4: Algonquin Monthly Basis Assumptions (2018$/MMBtu) 12
Figure IV-5: Northern New England Basis Differential to Rest of New England (Algonquin Citygates) 13
Figure IV-6: Delivered (Algonquin Citygate) Natural Gas Price Comparison (2018$/MMBtu).14
Figure IV-7: CO_2 Price Outlook 15
Figure IV-8: Cumulative Capacity Additions and Retirements 17
Figure IV-9: Renewable Buildout 18
Figure IV-10: Distributed Solar Buildout (Cumulative MW) 19
Figure V-1: Annual Vermont Zonal Price Forecast 20
Figure V-2: Monthly Vermont Zonal Price Forecast 21

TABLE OF TABLES

Table I-1: Variations in Natural Gas and CO_2 Price Assumptions 2
Table III-1: External Interface Limits 6
Table III-2: Internal Interface Limits 7

I. EXECUTIVE SUMMARY

Daymark Energy Advisors (Daymark) performed an energy market analysis in support of the Vermont Electric Cooperative (VEC) 2019 Integrated Resource Plan (IRP). The analysis uses Daymark's Northeast Market Model (NMM) to forecast Vermont zonal Locational Marginal Prices (LMPs) for the 20-year study period 2019 – 2038.

Recognizing uncertainty inherent in any forecast of future market conditions, Daymark also provided reasonable high- and low-price scenarios. The variance in the three different cases is driven by changes in assumed natural gas and CO_2 prices. Energy prices are very sensitive to natural gas and CO_2 price assumptions and these assumptions are also subject to a large amount of uncertainty, which is why they were varied to create the three sensitivities. The variation in natural gas and CO_2 price assumptions is summarized in the table below. More details on these inputs and other model inputs are provided in the following section. More details on the results are provided in Section V.

Table I-1: Variations in Natural Gas and CO_2 Price Assumptions

CASE	HENRY HUB PRICE	AGT BASIS PRICE	CO_2 PRICE
Reference	STEO + AEO CAGR	GasBasis Model	RGGI, Fed program (Synapse Low) in 2027
Low	Forward Quotes	[Same as Reference]	RGGI only (no fed program)
High	[Same as Reference]	Forward Quotes	[Same as Reference]

This report describes the energy market analytical methodology, provides details on key model inputs and assumptions, and shows Vermont zone prices for Reference, High and Low Cases. Annual average prices are shown for each case below.

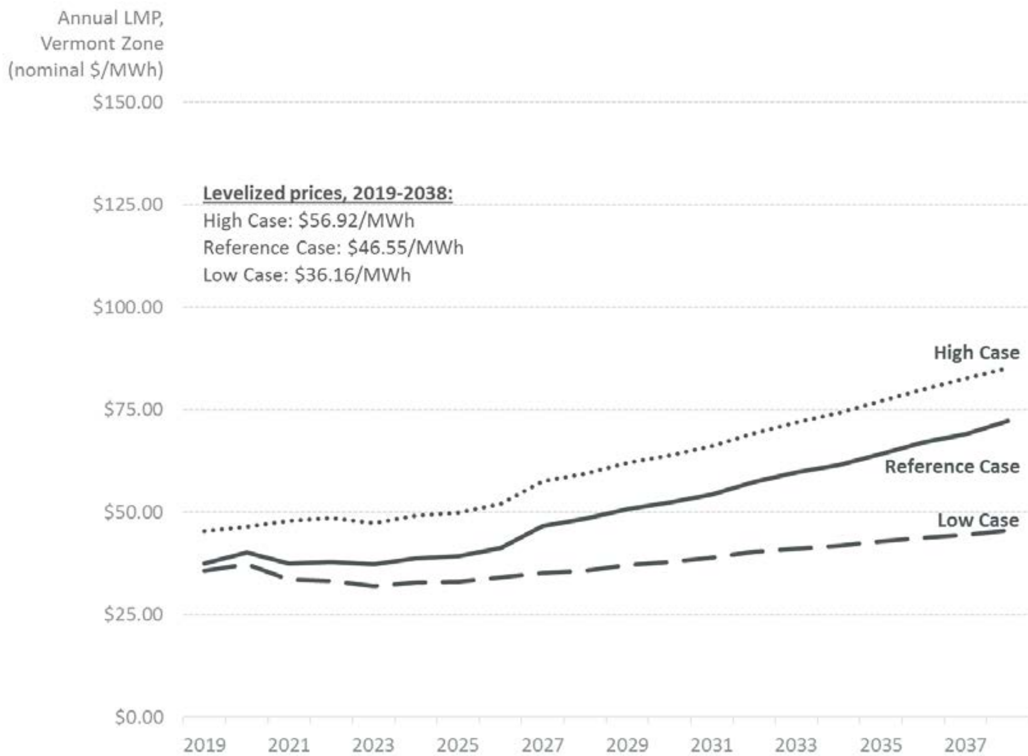

Figure I-1: Vermont Zonal Prices for Reference, High, and Low Cases

II. MODEL OVERVIEW

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

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

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

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

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

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

III. SYSTEM TOPOLOGY

The NMM is a zonal model where each defined zone represents a “bubble” of load and generation. Transmission is represented as single composite links between zones with constraints on certain combinations of links to realistically represent the interfaces. Key attributes that can be defined for each individual link are wheeling costs, transfer losses, and transfer capability. The topology of ISO New England and contiguous areas within the NMM are shown in Figure III-1, below. Links among external zones are not shown. Also represented in the NMM topology, but not shown in the diagram below, are zones representing the rest of NYISO, PJM, Ontario, and the Canadian Maritimes and their interconnecting links.

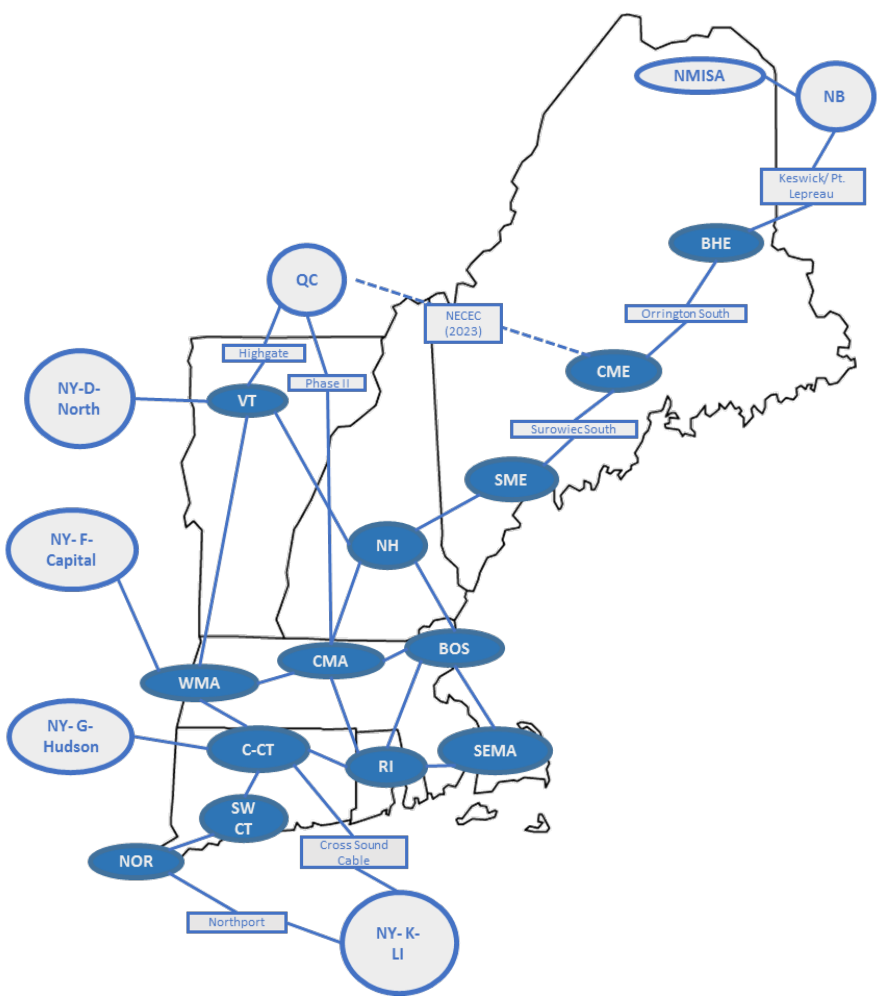

Figure III-1:NMM Topology: ISO New England and regional interconnections

In addition to individual links, NMM also defines constraints over multiple links to represent interface limits. The following tables show how ISO New England external and internal interface limits are represented in the NMM. Key data sources include the ISO-New England transmission transfer capabilities assumptions for Forward Capacity Auction 13[1] and the New York State Reliability Council 2018 Installed Capacity Requirement study.[2] The New England Clean Energy Connect project, winner of the Massachusetts Section 83D Clean Energy Request for Proposals, is expected to come online in 2023, bringing 1,200 MW of hydroelectric power from Hydro Québec to the Central Maine zone and increasing the transfer limit over the Surowiec South interface by 1,000 MW. We assume no other changes in topology over the study period.

Table III-1: External Interface Limits

NAME	ISO-NE ZONE	EXTERNAL ZONE	LIMITS (MW) EXPORT	IMPORT
New Brunswick-New England	BHE	New Brunswick	-------	1,000
HQ-NE (Highgate)	VT	HQ	-------	200
HQ-NE (Phase II)	CMA	HQ	-------	1,400
HQ-NE (NECEC)	CME	HQ	-------	0 / 1,200 [(a)]
Cross-Sound Cable	C-CT	NYISO-K	330	330
Northport-Norwalk Cable	NOR	NYISO-K	404	414
AC Ties	C-CT	NYISO-G	600	600
	WMA	NYISO-F	800	800
	VT	NYISO-D	-------	-------
AC Ties to New York (including Northport)			1,400	1,400

Notes: (a) Increase in 2023

[1] ISO-NE Presentation (4/26/2018). *Forward Capacity Auction 13 Transmission Transfer Capabilities and Capacity Zone Development*. https://www.iso-ne.com/static-assets/documents/2018/04/a9_fca13_zonal_development.pdf.

[2] New York State Reliability Council (12/8/2017). New York Control Area Installed Capacity Requirement for the period May 2017 to April 2018. See Appendix A, p 34. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B707FDBF5-5464-4E4D-8284-E776660AFC53%7D.

Table III-2: Internal Interface Limits

INTERFACE NAME	ZONE A	ZONE B	LIMITS (MW)	
			A TO B	B TO A
Orrington South	BHE	CME	1,325	1,325
Surowiec South	CME	SME	1,600 / 2,600 [a]	1,600 / 2,600 [a]
Maine-New Hampshire	SME	NH	1,960	1,960
North-South	VT	WMA	2,725	2,725
	NH	CMA		
	NH	Boston		
	VT	WMA		
East-West	VT	NH	3,500	2,200
	WMA	CMA		
	C-CT	RI		
Boston Import	NH	Boston	5,700	5,700
	CMA	Boston		
	RI	Boston		
	SEMA	Boston		
SEMA/RI Export	RI	C-CT	3,400	1,280
	RI	CMA		
	RI	Boston		
	SEMA	Boston		
Connecticut Import	RI	C-CT	3,400	3,400
	WMA	C-CT		
	NYISO-G	C-CT		
	NYISO-K	NOR		
SW Connecticut Import	SWCT	C-CT	2,800	2,800
	NYISO-K	NOR		

Notes: (a) Increase in 2023

IV. KEY INPUTS

The goal of this analysis is to project Vermont zonal energy prices. This section provides details on the key modeling inputs and assumptions used in the NMM energy market analysis.

A. Load

The load forecast used in the NMM for New England is based on the 2018 CELT report. Since the zones modeled in the NMM align with the Regional System Plan (RSP) zones, we used the forecast values by RSP zone directly from the CELT report.

For the forecast years through 2027, the 2018 CELT report provided gross peak and energy load, as well as peak and energy load net of energy efficiency (EE)[3] and behind-the-meter solar photovoltaic (BTM PV) generation. ISO New England's passive demand response (PDR) forecast in the CELT report includes estimates based on both the resources cleared in the ISO New England Forward Capacity Market (FCM) and the anticipated load reductions from state-sponsored EE and demand response programs. For extrapolation in modeled years after 2027, gross load is assumed to grow at the compound annual growth rate from 2022-2027. EE reductions are extrapolated such that EE's percent of gross load, both peak and energy, in 2027 remains constant through the rest of the study period. These extrapolations are done separately for each zone in the system.

Figure IV-1 below shows the 2018 CELT-based forecasts of gross and net coincident peak demand and Figure IV-2 shows the gross and net energy load for the New England Control Area.

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

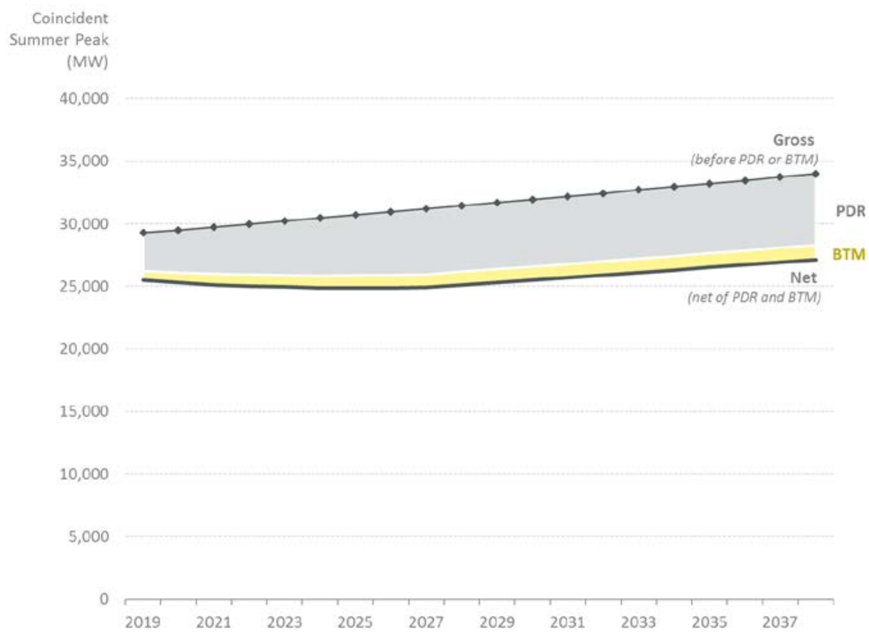

Figure IV-1: New England Coincident Peak Demand, Gross, Net of Passive Demand Response (PDR), and Behind-the-Meter Solar (BTM)

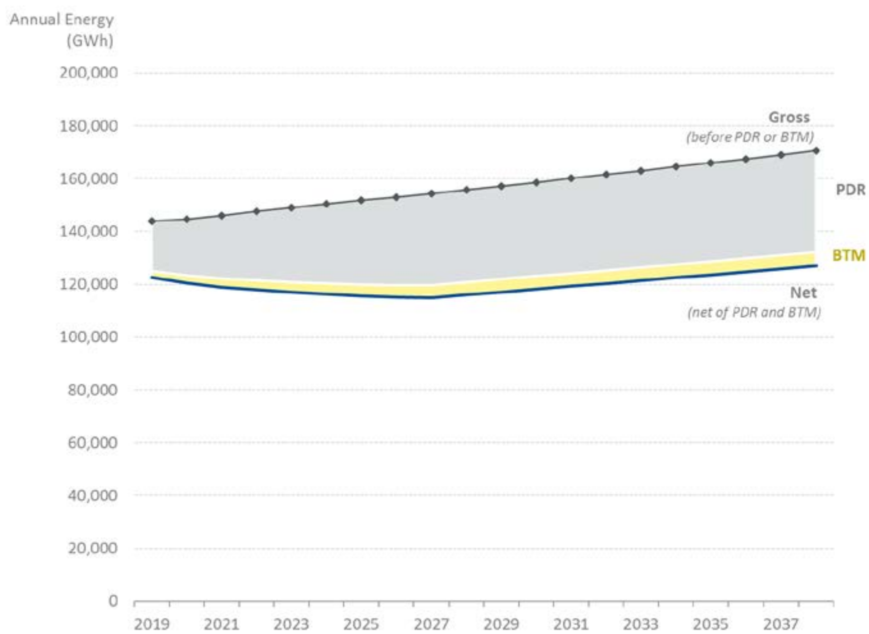

Figure IV-2: New England Energy Load, Gross Net of Passive Demand Response (PDR), and Behind-the-Meter Solar (BTM)

B. Fuel Prices

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

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

The price of natural gas for each New England generator is constructed according to the following basic formula for a given month, m:

$$\mathbf{DP}_m = \mathbf{HH}_m + \mathbf{IP}_m + \mathbf{R}_m + \mathbf{p}$$

Where:

DP	=	Delivered price to generator
HH	=	Henry Hub price
IP	=	Index price basis differential from Henry Hub to Algonquin Citygate
R	=	Regional adder, if any
p	=	Peaking unit adder

The peaking unit adder is used for a few inefficient generators that are only likely to operate on peak demand days when daily gas prices are likely higher than the monthly average.

The derivation of each of the remaining components of the equation above is explained in the following sections.

Henry Hub

Daymark used the U.S. EIA's 2018 Annual Energy Outlook (AEO) and Short Term Energy Outlook (STEO) Reference Case assumptions of Henry Hub natural gas commodity prices. The AEO is a publicly-available long-term annual forecast and STEO is a publicly-available short-term monthly forecast; both are commonly used in the energy industry.

Reference Case: The Reference Case combines the 2018 AEO trends with updated monthly forecast from July 2018 STEO. The Reference Case relies on the STEO through December 2019, and then grows at 3.90%, which is the 2018 AEO's 2017-2050 compound annual growth rate. This approach combines short term price outlooks based on more recent STEO modeling with longer-term fundamental trends captured in the AEO. Figure IV-3 shows the assumptions for the Reference Case.

Low Case: The Low Case is based on NYMEX future quotes. NYMEX futures are an average of quotes from trading days 9/1/17 through 8/31/18 for delivery months through 2023. After 2023, a long-term equilibrium price is assumed based on a monthly average of 2022 and 2023 monthly prices, held constant in real dollars for the rest of the study period.

High Case: same as the Reference Case.

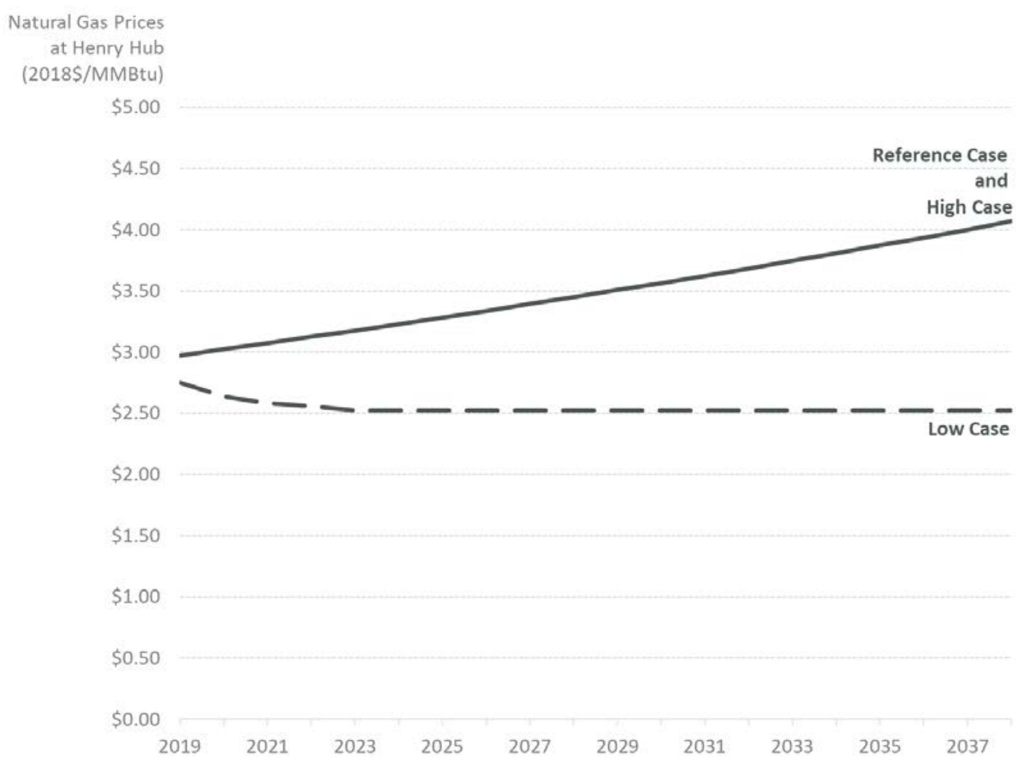

Figure IV-3: Henry Hub Gas Price Assumptions (2018$/MMBtu)

Region-specific gas indices

The region-specific indices for New England, New York, and the PJM RTO represented in the NMM include Algonquin Citygate, NY Transco Zone 6, TETCO M3, Iroquois Zone 2, and Dominion South.

Reference Case: The Reference Case was developed using Daymark's proprietary GasBasis model, which applies Monte Carlo simulation of natural gas basis prices at market trading locations based on pipeline headroom projections. The GasBasis model takes natural gas pipeline capacity, LDC demand, electric demand, imports and renewable additions, as well as historical natural gas basis as the inputs. It calculates available natural gas pipeline capacity based on forecasted natural gas supply and demand for relevant pricing hubs, and simulates future basis prices.

Low Case: same as the Reference Case.

High Case: The High Case is based upon OTC Global Holdings (OTCGH) future quotes obtained through S&P Global Market Intelligence. OTCGH futures used for this analysis are an average of quotes from trading days 9/1/17 through 9/28/18 for delivery months through 2023. After 2023, a long-term equilibrium price is assumed based on a monthly average of 2022 and 2023 monthly prices, held constant in real dollars for the rest of the study period.

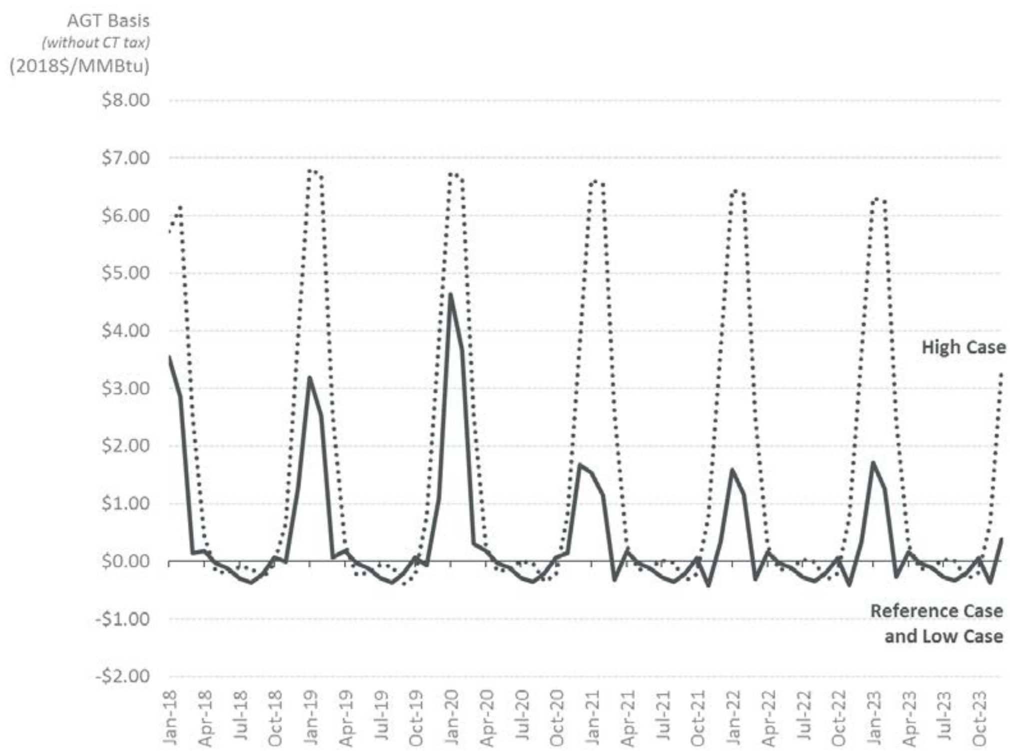

Figure IV-4: Algonquin Monthly Basis Assumptions (2018$/MMBtu)

Regional adders

The Algonquin Citygates price provides a reasonable proxy for delivered natural gas prices for generators in southern New England. However, natural gas-fired generators in northern New England (Maine, New Hampshire, and Vermont) face additional expense due to the additional distance gas supplies travel from the southwestern part of New England. The NMM forecast of this additional basis is $0.85/MMBtu on an annual average basis, with seasonal range of $0.51/MMBtu to $1.28/MMBtu (see Figure IV-5). The forecast is based on interruptible transportation rates on the Portland Natural Gas Transmission System.

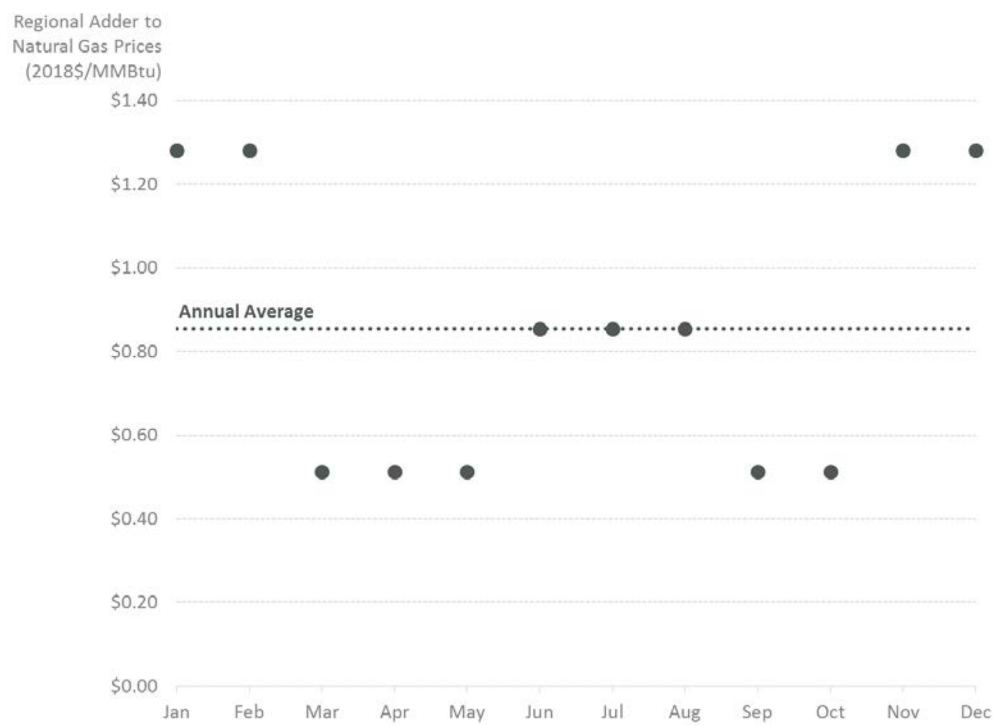

Figure IV-5: Northern New England Basis Differential to Rest of New England (Algonquin Citygates)

A 5% seasonal Connecticut state tax was incorporated in the gas prices for generators located in Connecticut zones during the winter months of November through March.

New England Delivered Gas Prices

The following chart shows annual average gas prices delivered to New England for the Reference, High and Low Cases. These prices do not reflect any northern New England or Connecticut regional adders.

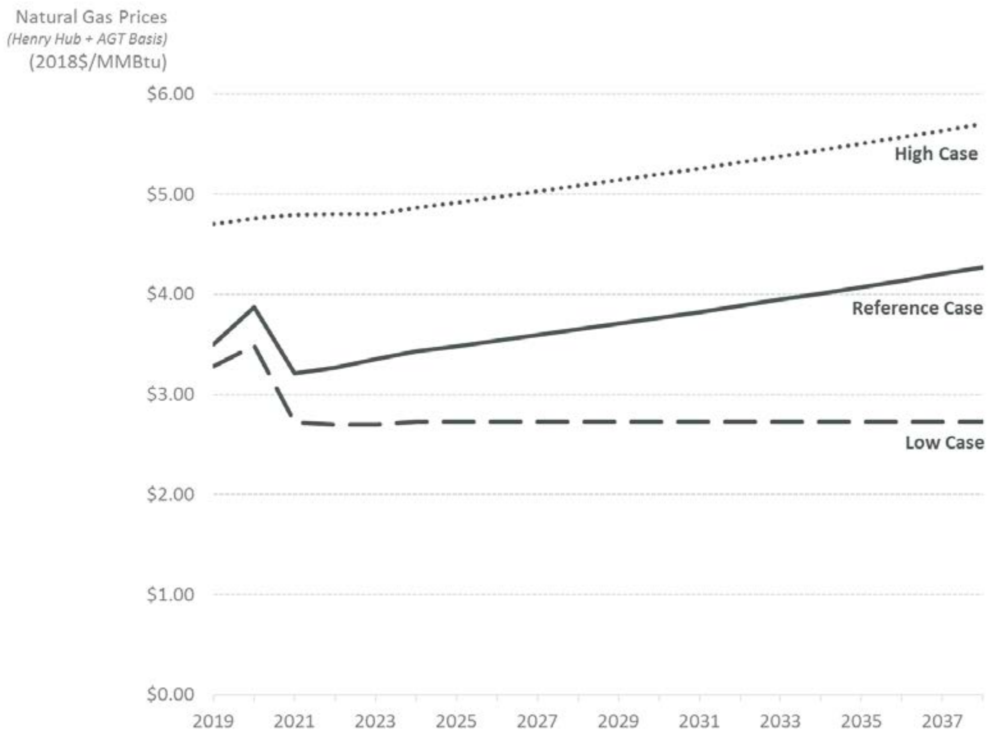

Figure IV-6: Delivered (Algonquin Citygate) Natural Gas Price Comparison (2018$/MMBtu).

C. Emission Prices

The NMM incorporates emission prices into the production cost and commitment (or dispatch) of units.

Two CO_2 price outlooks are used in this analysis. The Low Case only incorporates the impact of the 2017 IPM RGGI Update,[4] whereas the Reference Case and High Case both assume federal carbon regulations complement the RGGI program starting in 2027.

RGGI: All New England states currently participate in the Regional Greenhouse Gas Initiative (RGGI) program, a cap-and-trade program aimed at reducing CO_2 emissions from the power sector. Pricing carbon emissions affects New England electric energy prices by increasing the variable costs of fossil fuel-fired generators that are almost always on the margin. A RGGI-commissioned study of the Updated Model Rule projects that emission allowance prices will rise from $5.33 (2015$) per ton in 2017 to $9.77

[4] Source: RGGI Program Review, RGGI, Inc. Available at: https://rggi.org/program-overview-and-design/program-review

(2015$) per ton in 2031. The NMM incorporates this updated outlook on RGGI allowance prices.

Federal Policy: The federal CO_2 emission price outlook comes from 2016 Synapse CO_2 Price Forecast.[5] Synapse reviews policy and regulatory developments as well as utility price forecasts to develop Low, Mid, and High scenario CO_2 emission price forecasts. We believe the Synapse "Low" forecast, which assumes that "*Clean Power Plan compliance is relatively easy, and a similar level of stringency is assumed after 2030…*"[6] is most appropriate for use as a reference forecast of federal carbon pricing, with a 5-year delay in the implementation of a federal policy. The High Case assumes that a federal CO_2 pricing program is implemented in 2027 as forecasted in 2022 in the Synapse "Low" case. Using the "Low" case and delaying onset of federal controls to 2027 provides a relatively conservative "High Carbon" case considering the current political climate that makes immediate action at the federal level unlikely.

The CO_2 price outlooks are summarized in Figure IV-7.

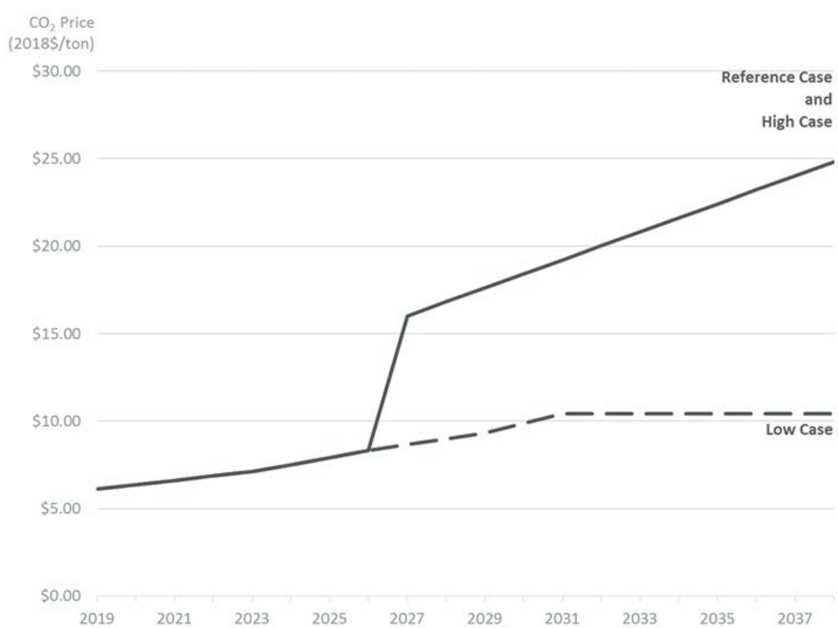

Figure IV-7: CO₂ Price Outlook

[5] Source: Synapse Energy Economics, Inc. *Spring 2016 National Carbon Dioxide Price Forecast*. March 16, 2016. Available at http://www.synapse-energy.com/project/synapse-carbon-dioxide-price-forecast

[6] *Spring 2016 National Carbon Dioxide Price Forecast*, p 4, March 16, 2016. http://www.synapse-energy.com/project/synapse-carbon-dioxide-price-forecast

D. Retirements and Thermal Capacity Additions

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

Our assumptions on retirements in the first few years of the study period are based on known and forecasted retirements in the ISO New England Forward Capacity Market (FCM). The primary source of the specific resource additions and retirements are the results of the ISO New England Forward Capacity Auctions ("FCA") through FCA 12, which determined capacity obligations through the 2021-2022 commitment period. In addition to these resources, further retirements and resource additions are based on results of analysis conducted with Daymark's proprietary CapMarket Model simulating the ISO New England FCM.

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

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

The model uses the ISO New England demand curve to determine the market clearing price for each auction, which in turn determines the retirements and buildout. As the auctions progress through the study period, clearing prices impact the economics of existing units, and when going-forward costs exceed the capacity revenue, a resource may be retired. The loss of that capacity has a consequent impact on the clearing price. When the clearing price is sufficient to attract new entrants to the market, additional capacity is added, again impacting the FCA clearing price. New policy-driven renewable resources are assumed to acquire capacity supply obligations from retiring resources after the FCA, up to technology-specific capacity values. The result of the model is a schedule of retirements of existing resources and additions of new generic capacity in the region, as well as the annual FCA clearing prices.

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

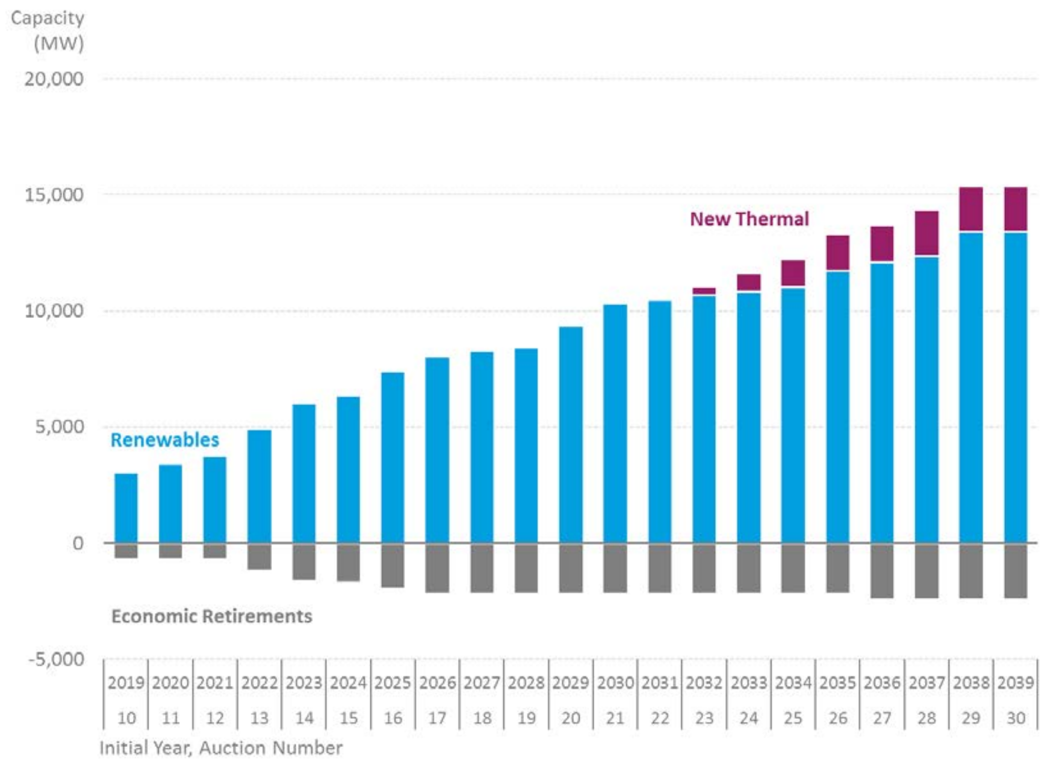

Figure IV-8: Cumulative Capacity Additions and Retirements

E. Renewable Additions

The judgment of renewable buildout was made from known procurements, which was then supplemented with additional resources to match REC supply and demand. Figure IV-9 summarizes the renewable buildout developed in this analysis.

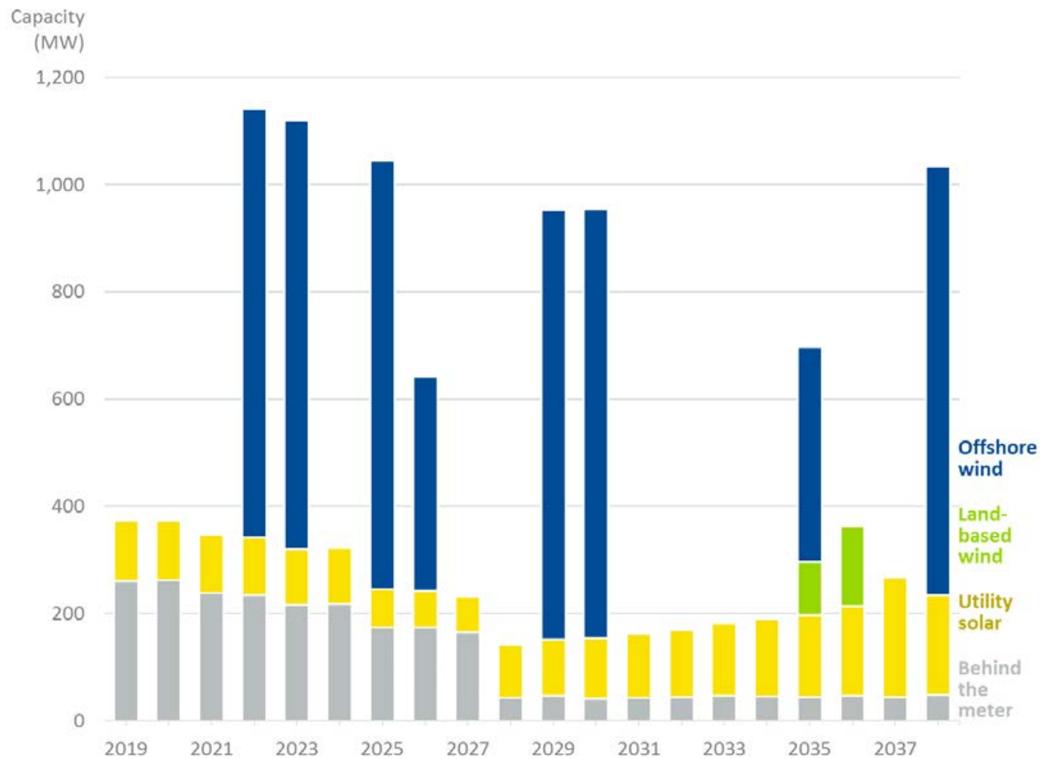

Figure IV-9: Renewable Buildout

Distributed solar assumptions

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

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

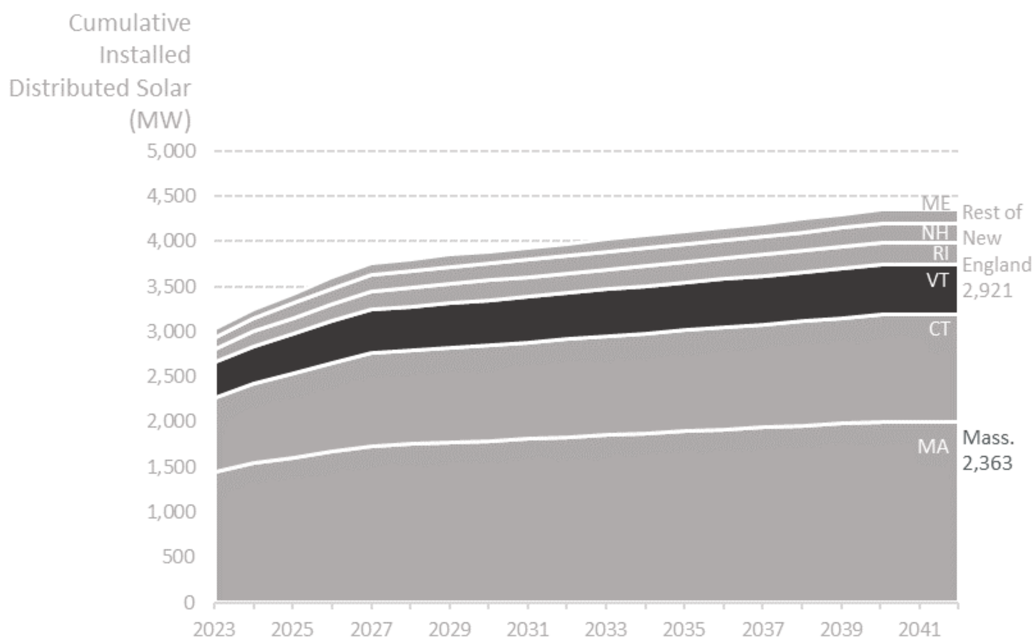

Figure IV-10: Distributed Solar Buildout (Cumulative MW)

V. RESULTS

The figures below show the forecasted Vermont zonal prices for the Reference, High and Low Cases on an annual and monthly basis. Levelized prices assume a discount rate of 6.0% for the 20-year study period 2019 – 2038.

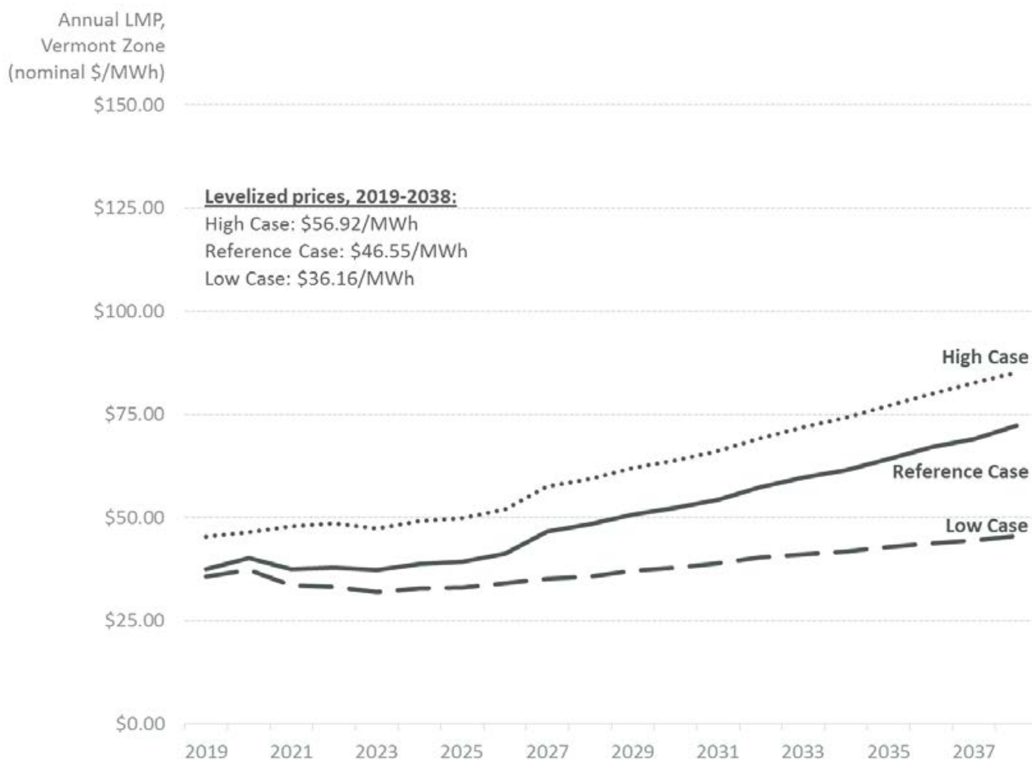

Figure V-1: Annual Vermont Zonal Price Forecast

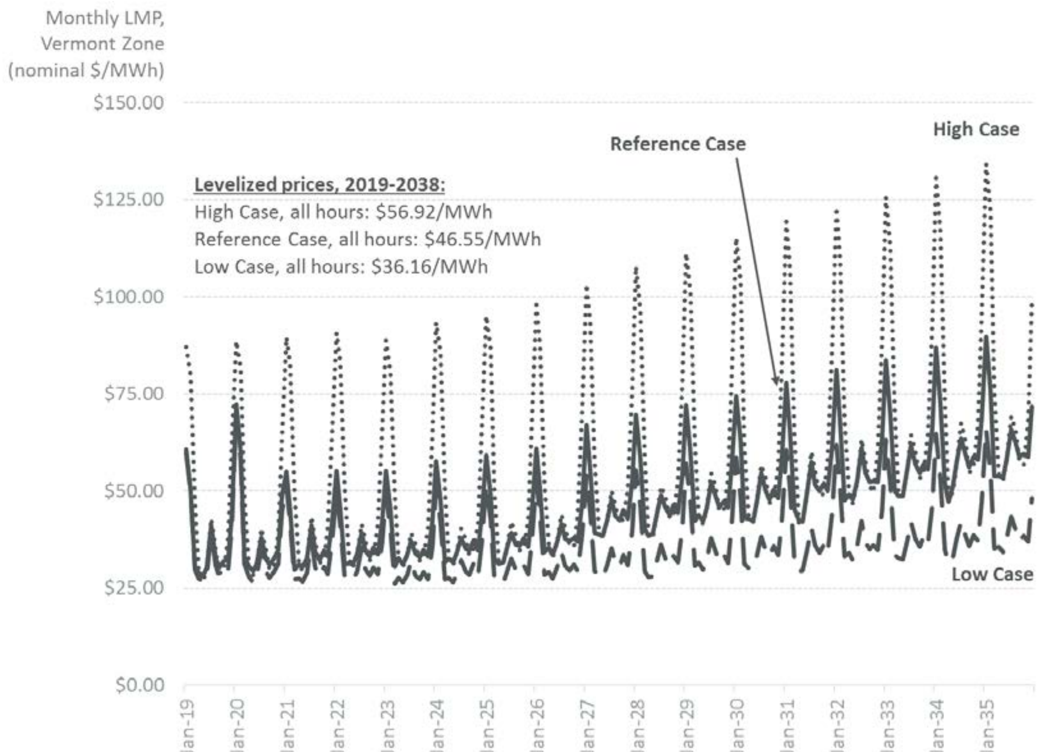

Figure V-2: Monthly Vermont Zonal Price Forecast