4. Declining Electricity Demand

DECREASED SALES, INCREASED KILOWATT HOURS

As we transition to a new energy future, Green Mountain Power customers are buying less energy today than they were at the end of 2003. Sales of baseload energy in Vermont have declined to levels last seen fifteen years ago.

Sustained investments in energy efficiency at the local and federal levels are a part of this decline, and Vermonters also have the opportunity to buy and install their own solar energy systems on their homes and businesses or take part in group solar energy systems to satisfy all or part of their energy needs. Since 2008, Vermont's net-metering program within GMP has grown to include almost 10,000 residential customers and almost 2,700 businesses whose primary source of electricity is from either self-generation or providers other than GMP.

There is no doubt that Vermont's net-metering program has helped the state advance toward a renewable energy future and achieve environmental goals. We have been a key partner in these successes and have far exceeded our own carbon reduction goals in 2017. We are set to exceed them again in 2018.

Net metering helps attain renewable generation targets, and it also leads to reduced demand, and thus reduced sales to support the infrastructure and innovation our customers need. This situation of declining sales, spread among fewer customers, is a sign of success and also a cost issue that presents challenges for us, our customers, and state policymakers and regulators.

SALES AND DEMAND IN THE PLANNING PROCESS

Sales and demand form a foundational standard for integrated resource planning.

Historically, we could plan for consistent year-over-year sales growth. For example, Table 4-1 shows average growth in sales for the decade from 1995 through 2004. While our Vermont weather annually affects sales differently, the overall pattern of sales grow is unmistakable.

Year	Retail Sales (MWh)	Annual Change (MWh)	Annual Change (%)
1995	3,794,311	—	—
1996	3,882,150	87,839	2.3%
1997	3,934,251	52,101	1.3%
1998	3,966,877	32,626	0.8%
1999	4,074,581	107,704	2.7%
2000	4,150,626	76,045	1.9%
2001	4,117,206	–33,420	–0.8%
2002	4,129,799	12,593	0.3%
2003	4,131,891	2,092	0.1%
2004	4,211,602	79,711	1.9%
Total Change / Average Change Percentage		**417,291**	**1.2%**
Compounded Average Growth Rate (Reported to FERC)			**1.2%**

Table 4-1. Legacy GMP and CVPS Combined Retail Sales, 1995–2004

Recent projections, however, forecast essentially flat sales. Our 2015 IRP Load Forecast Report, which formed the basis of our 2014 IRP, indicated that we could expect 0.2% annual growth between 2017 and 2028 (Table 4-2). This represents approximately an 85% reduction in sales growth over two decades before (0.2% versus 1.2%).

Year	Retail Sales (MWh)	Annual Change (MWh)	Annual Change (%)
2017	4,283,851	—	—
2018	4,287,010	3,159	0.1%
2019	4,287,332	322	0.0%
2020	4,280,655	–6,677	–0.2%
2021	4,265,783	–14,872	–0.4%
2022	4,272,630	6,847	0.2%
2023	4,283,191	10,561	0.2%
2024	4,300,610	17,419	0.4%
2025	4,305,751	5,141	0.1%
2026	4,319,724	13,973	0.3%
2027	4,336,678	16,954	0.4%
2028	4,363,099	26,421	0.6%
	Total Change / Percent	**79,248**	**0.2%**

Table 4-2. 2015 Retail Sales Forecast

The 2019 Budget Forecast Report (discussed in Appendix B), which forms the foundation of analysis for our 2018 IRP, projects sales erosion similar to those projections from our 2014 IRP. According to the forecast (Table 4-3), sales between 2017 and 2028 are expected to decline on average by 0.2% annually. In 2015, total 2017 retail sales were forecast to be approximately 4,300,000 MWh; in reality, we did not achieve that projection. Sales over the next decade are now not expected to reach that projected amount either; rather they are projected to steadily decline. Sales are expected to reach less than 4,100,000 MWh by 2028, or approximately 5% lower than the forecasted 2017 retail sales had been predicted in the 2014 IRP.

Year	Residential (MWh)	Chg	Commercial (MWh)	Chg	Industrial (MWh)	Chg	Other (MWh)	Chg	Total (MWh)	Chg
2008	1,559,231	–	1,584,987	–	1,063,320	–	10,710	–	4,218,248	–
2009	1,544,874	–0.9%	1,530,564	–3.4%	973,631	–8.4%	10,780	0.7%	4,059,848	–3.8%
2010	1,558,457	0.9%	1,534,895	0.3%	1,013,453	4.1%	10,918	1.3%	4,117,722	1.4%
2011	1,552,270	–0.4%	1,527,244	–0.5%	1,073,557	5.9%	11,414	4.5%	4,164,485	1.1%
2012	1,520,840	–2.0%	1,538,905	0.8%	1,169,331	8.9%	10,645	–6.7%	4,239,721	1.8%
2013	1,562,370	2.7%	1,550,572	0.8%	1,178,595	0.8%	8,443	–20.7%	4,299,981	1.4%
2014	1,568,689	0.4%	1,559,491	0.6%	1,177,033	–0.1%	6,887	–18.4%	4,312,099	0.3%
2015	1,539,045	–1.9%	1,531,148	–1.8%	1,168,796	–0.7%	5,274	–23.4%	4,244,263	–1.6%
2016	1,483,553	–3.6%	1,530,603	0.0%	1,188,527	1.7%	4,852	–8.0%	4,207,536	–0.9%
2017	1,465,612	–1.2%	1,516,541	–0.9%	1,170,493	–1.5%	4,453	–8.2%	4,157,098	–1.2%
2018	1,467,655	0.1%	1,518,210	0.1%	1,175,494	0.4%	4,760	6.9%	4,166,119	0.2%
2019	1,440,878	–1.8%	1,521,410	0.2%	1,179,223	0.3%	4,760	0.0%	4,146,271	–0.5%
2020	1,425,189	–1.1%	1,528,236	0.4%	1,173,906	–0.5%	4,760	0.0%	4,132,091	–0.3%
2021	1,404,761	–1.4%	1,528,060	0.0%	1,175,862	0.2%	4,760	0.0%	4,113,442	–0.5%
2022	1,390,565	–1.0%	1,529,039	0.1%	1,178,369	0.2%	4,760	0.0%	4,102,733	–0.3%
2023	1,378,673	–0.9%	1,529,121	0.0%	1,178,659	0.0%	4,760	0.0%	4,091,212	–0.3%
2024	1,370,041	–0.6%	1,530,529	0.1%	1,178,567	0.0%	4,760	0.0%	4,083,897	–0.2%
2025	1,359,059	–0.8%	1,532,087	0.1%	1,177,505	–0.1%	4,760	0.0%	4,073,410	–0.3%
2026	1,350,439	–0.6%	1,534,800	0.2%	1,175,797	–0.1%	4,760	0.0%	4,065,796	–0.2%
2027	1,345,652	–0.4%	1,538,443	0.2%	1,174,086	–0.1%	4,760	0.0%	4,062,941	–0.1%
2028	1,344,158	–0.1%	1,542,812	0.3%	1,173,789	0.0%	4,760	0.0%	4,065,519	0.1%
2008–2017		–0.7%		–0.5%		1.2%		–8.8%		–0.1%
2017–2020		**–0.9%**		**0.3%**		**0.1%**		**2.3%**		**–0.2%**
2020–2028		–0.8%		0.2%		0.0%		0.6%		–0.2%

Table 4-3. Customer Class Cost-of-Service Billed Sales Forecast (MWh)

Starting in 2015, the sucesses of solar net metering together with energy efficiency measures associated with LED lights and energy-efficient appliances, gained greater momentum, causing a decrease in electricity sales.

Table 4-4 compares projected retail sales from 2015, just four years ago, to the retail sales we are now forecasting in 2018.

Year	2015 Forecasted Retail Sales (MWh)	2019 Forecasted Retail Sales (MWh)	Annual Change (%)
2017	4,283,851	4,157,098	–3.1%
2018	4,287,010	4,166,119	–2.9%
2019	4,287,332	4,146,271	–3.4%
2020	4,280,655	4,132,091	–3.6%
2021	4,265,783	4,113,442	–3.7%
2022	4,272,630	4,102,733	–4.1%
2023	4,283,191	4,091,212	–4.7%
2024	4,300,610	4,083,897	–5.3%
2025	4,305,751	4,073,410	–5.7%
2026	4,319,724	4,065,796	–6.3%
2027	4,336,678	4,062,941	–6.7%
2028	4,363,099	4,065,519	–7.3%

Table 4-4. Sales Comparison: 2015 Retail Sales Forecast versus 2019 Retail Sales Forecast

Figure 4-1 shows how the sales forecast in 2015 projected a slight increase over the next decade, whereas the 2019 Budget Forecast Report depicts a slight decline over the same time period—a dramatic shift over the course of just four years.

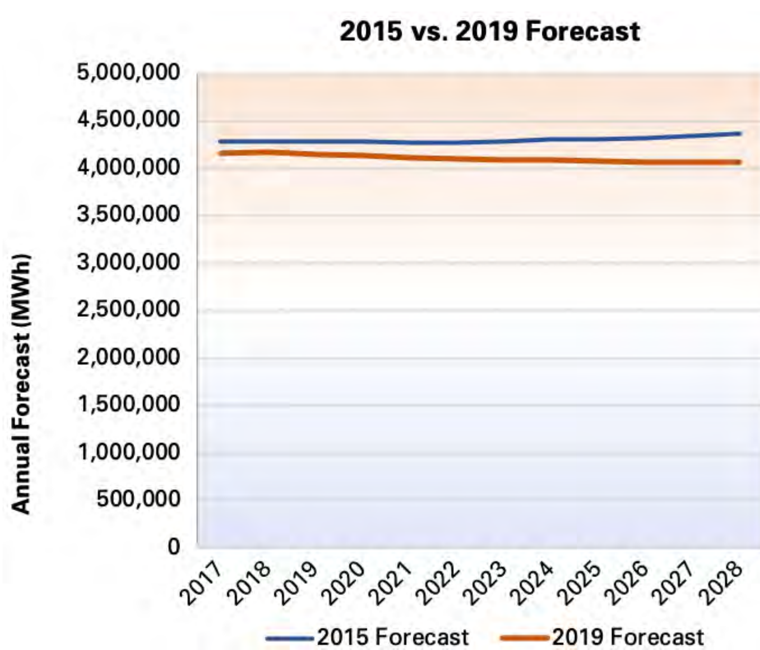

Figure 4-1. Comparison of 2015 Retail Sales Forecast versus 2019 Retail Sales Forecast Trends

Traditionally, higher customer growth led to higher retail sales, but that trend has completely changed. Table 4-5 shows that while the forecasted growth in the number of customers from 1995–2004 has slowed from a rate of approximately 1.0% to a forecasted rate of 0.4% over the next decade, the percentage increase is still positive.

Year	Number of Customers	Annual Increase	Annual % Change	Year	Number of Customers	Annual Increase	Annual % Change
1995	218,718	—	—	2018	264,482	—	—
1996	220,835	2,117	1.0%	2019	265,610	1,128	0.4%
1997	222,206	1,371	0.6%	2020	266,423	813	0.3%
1998	223,824	1,618	0.7%	2021	267,284	861	0.3%
1999	225,092	1,268	0.6%	2022	268,439	1,155	0.4%
2000	227,826	2,734	1.2%	2023	269,608	1,169	0.4%
2001	230,526	2,700	1.2%	2024	270,785	1,177	0.4%
2002	233,161	2,635	1.1%	2025	271,980	1,195	0.4%
2003	236,144	2,983	1.3%	2026	273,150	1,170	0.4%
2004	238,519	2,375	1.0%	2027	274,275	1,125	0.4%
—	—	—	—	2028	275,359	1,084	0.4%
	Average Change	19,801	—		Average Change	10,877	—
Compounded Average Growth Rate (CAGR)			1.0%	Compounded Average Growth Rate (CAGR)			0.4%

Table 4-5. Historical and Forecasted Growth in Number of Customers Comparison

Year-over-year increases in the number of customers during the decade of 1995 through 2004 corresponded to an increase in sales as depicted in Table 4-1. Table 4-5 projects that, over the next decade, while the number of customers continues to grow, this growth corresponds with declining demand.

FACTORS AFFECTING CONSUMPTION

Six main factors affect retail sales forecasts: three reduce sales and three increase sales.

Sales Reducers. Energy efficiency, appliance standards, and solar net metering.

Sales Increasers. Economic and household growth, the newer technologies of heat pumps and electric vehicles, and additional strategic electrification.

Energy Efficiency and Appliance Standards

The impact of efficiency upon retail sales arises from several different sources. As stated in the 2019 Budget Forecast Report: "Factors driving change in stock efficiency include new end-use standards, state efficiency programs that either subsidize the cost of more efficient end-use options or provide new end-use measures such as lighting and weatherization as part of home and business units, and just natural turnover of existing equipment with more efficient equipment."[40]

Retail sales forecasts contained both Efficiency Vermont's (EVT's) most current energy efficiency savings projections as well as EIA's Annual Energy Outlook for 2017 end-use efficiency estimates for the New England Census Division. Table 4-6 summarizes the impact of energy efficiency and appliance standards upon our retail sales forecast. The incremental efficiencies employed between 2018 and 2028 result in our retail sales being approximately 238,000 MWh (or almost 6%) lower than they otherwise would be.

Our analysis captured 90% of residential energy efficiencies, thus applying 10% of forecasted energy efficiency to future loads (to avoid double counting). We expect that a greater portion of energy efficiency will be captured by our future analysis. Thus, energy efficiency is imbedded in load and not captured in Table 4-6.

Over the next 10 years, changes in both national and Vermont policy increasing support for efficiency measures, consistent with climate and other goals we support, could further affect these projections. That uncertainty requires monitoring throughout the planning period and beyond.

Year	Incremental (MWh)	Cumulative (MWh)
2018	–22,941	–22,941
2019	–27,508	–50,449
2020	–27,045	–77,494
2021	–30,565	–108,059
2022	–25,003	–133,062
2023	–22,928	–155,990
2024	–18,512	–174,502
2025	–20,751	–195,253
2026	–17,389	–212,642
2027	–13,354	–225,996
2028	–11,613	–237,609

Table 4-6. Energy Efficiency Impact on Retail Sales Forecast

[40] *Green Mountain Power 2019 Budget Forecast Report*, prepared by Itron, Inc., April 2, 2018; pages 12–13.

Solar Net Metering

Over the last six years, we have seen a rapid increase in the installed capacity of net-metered solar installations. Table 4-7 shows installed and cumulative MW by year.

Year	Installed Net Metering (MW)	Cumulative Installed Net Metering (MW)
1999	0.002	0.002
2000	0.001	0.003
2001	0.011	0.014
2002	0.020	0.030
2003	0.030	0.060
2004	0.030	0.090
2005	0.040	0.130
2006	0.090	0.220
2007	0.050	0.260
2008	0.460	0.720
2009	1.100	1.800
2010	2.600	4.400
2011	1.900	6.300
2012	3.400	9.700
2013	9.900	19.600
2014	21.400	41.100
2015	23.600	64.700
2016	38.900	103.600
2017	33.400	137.000
2018*	20.000	157.000

* Values as of November 16, 2018

Table 4-7. Installed Solar Net Metering: 1999–2018

Net-metered solar in our service territory remained relatively dormant until the introduction of our solar adder in 2007, which stimulated activity through a net metering credit that more accurately valued solar at that time. Since then, net-metered solar, from both rooftop and group installations, has grown steadily, especially over the past five years (Figure 4-2).

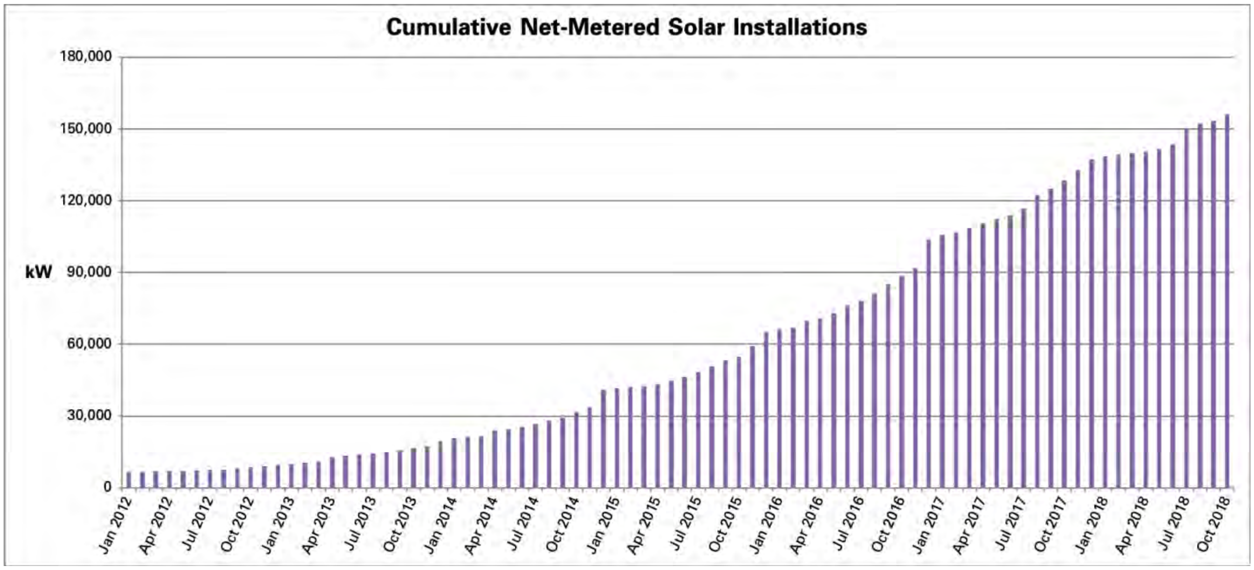

Figure 4-2. Net-Metered Solar Installation Growth: 2012–2018

We anticipate the rooftop solar net metering deployment to continue at a strong pace while the larger scale group net-metered projects (larger than 150 kW) should slow down slightly compared to the previous five years.

Solar installations that are not net-metered also continue to grow (Figure 4-3). These installations are typically larger facilities that are part of the Vermont Standard Offer program or that have PPAs with us and other Vermont utilities. Note that the cumulative kW from net-metered installations far outpaces those from non-net-metered facilities.

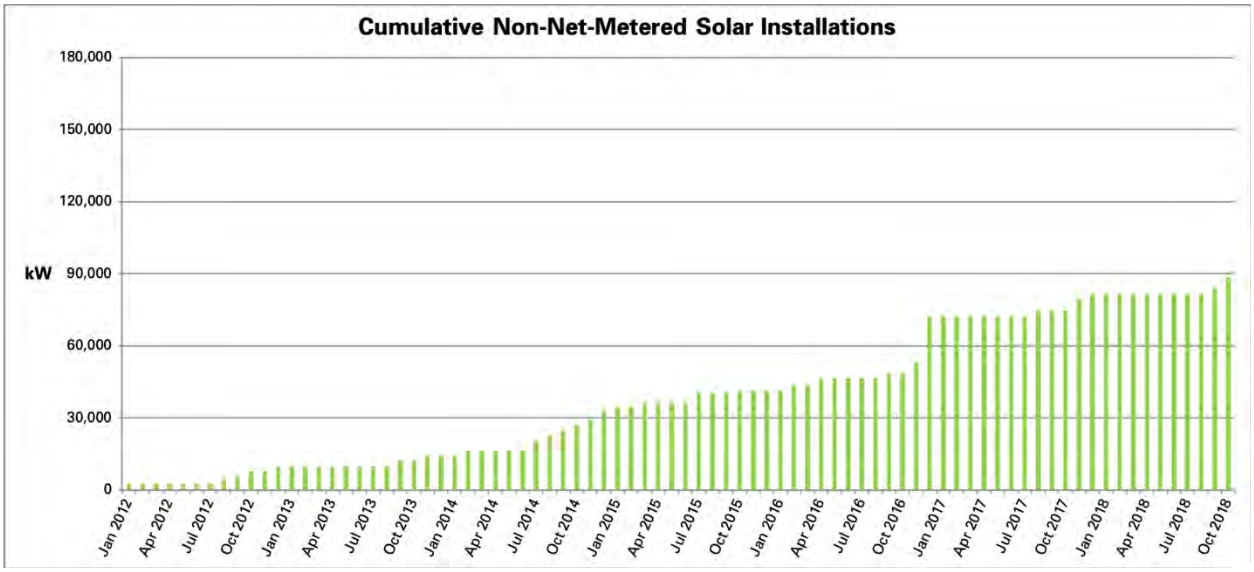

Figure 4-3. Non-Net-Metered Solar Installation Growth: 2012–2018

We developed a solar net metering installation forecast based upon both applications for a recent period (calendar year 2017) as well as historical attrition rates for those applications. After the completion of some older applications, we then used the same methodology to calculate annual installations to be approximately 24 MW per year.[41] This amount was used to forecast retail sales.

Because of both net metering rules and accounting principles, solar net metering affects both revenue and power supply expense. For customers that utilize net-metered solar, retail sales are lowered by the amount of power consumed onsite within the month that the offsetting generation was produced. Anything not consumed onsite within that month is considered 'excess' energy and creates a power supply expense in the month it was produced. This expense creates credits, which are then applied to reduce those customers' bills. In addition, the 'REC' adder that is paid to every kWh generated is treated as a power supply expense and is used to fulfill our Tier II obligation under the

[41] The portfolio evaluation (in Chapter 8) reflects a modestly slower net metering growth rate of 20 MW per year (which reflects more current information, including the PUC's biennial review of net metering payment rates) as a base case. It tests the implications of alternative growth rates of 10 MW per year and 30 MW per year. While this base case portfolio analysis does not match precisely with the financial forecast presented in this chapter, many of the portfolio model's key component inputs (including volumes and prices for major power sources, which drive most of our power costs) are the same, and the bottom-line cost projections are similar.

Vermont Renewable Energy Standard (RES) (as is discussed further in Chapter 5: Our Increasingly Renewable Energy Supply).

Solar net metering generation falls into one of two general categories: interconnected or group. Interconnected solar arrays are located directly on the customer premises behind the meter. This could be either a residential or a commercial customer location, and typically the energy produced is consumed by the individual customer. These arrays tend to have larger excesses during the summer, but much lower generation during the darker months. Since the generation is co-located with the customer who consumes the power, these installations reduce retail sales on a per MW basis greater than group net metering arrays.

Group solar arrays are typically connected directly to the distribution system and generate energy that is assigned to participating customers. Since the panels are typically not co-located with the end users, this arrangement results in almost all of energy being deemed as a power supply expense. Thus, the category of solar installations is important. These historical impacts on revenue per solar net metering MW were used to determine the impact upon retail sales.

Table 4-8 shows the incremental impact of solar net metering upon the retail sales forecast.

Year	Incremental (MWh)	Cumulative (MWh)
2018	–5,802	–5,802
2019	–11,602	–17,404
2020	–8,384	–25,788
2021	–8,284	–34,072
2022	–9,355	–43,427
2023	–8,334	–51,761
2024	–8,458	–60,219
2025	–8,211	–68,430
2026	–8,334	–76,764
2027	–8,334	–85,098
2028	–8,530	–93,628

Table 4-8. Solar Net Metering's Incremental Impact of Retail Sales Forecast

The incremental impact of solar net metering added over the next 10 years results in an approximate 2.2% further reduction of retail sales in 2028 compared with a scenario in which no new arrays are added.

Economic and Household Growth

Growth marks an increase in retail sales because of household and economic activity. Growth-related sales increases are still occurring in our service territory. Historically, growth was the only variable that affected retail sales; now growth is but one of several variables.

Based on recent trends (as show in Table 4-5), we fully expect the number of customers to continue to increase, albeit at a slower pace. Thus, we are planning on the forecasted growth of 0.4% per year in the number of customers (rather than the 1.0% per year pace seen during the period 1995-2004).

We also expect economic activity to grow. Moody's Analytics projects slowing household income growth affecting slower residential retail sales. The country's projected annual growth of 1.1% in commercial gross domestic product coupled with a 0.6% annual growth in employment is expected to have a positive, although not direct, effect on our retail sales. Table 4-9 shows the expected growth in retail sales because of these economic and household growth projections.

Year	Incremental (MWh)	Cumulative (MWh)
2018	21,889	21,889
2019	8,091	29,980
2020	9,117	39,097
2021	13,694	52,791
2022	16,780	69,570
2023	12,434	82,005
2024	11,823	93,828
2025	10,021	103,850
2026	8,904	112,753
2027	8,513	121,266
2028	11,006	132,272

Table 4-9. Economic and Household Growth's Incremental Impact of Retail Sales Forecast

Note that, by 2028, the projected *increase* in retail sales from economic and household growth (132,272 MWh) is slightly more than half of the projected *decrease* in retail growth from energy efficiency measures (–237,609 MWh) as depicted in Table 4-6. This results in an overall projected *decrease* in retail sales of 105,337 MWh by 2028. While this is good news for the achievement of key energy policy goals that we support and facilitate, it creates a real gap in revenue available to support infrastructure and innovation of our customers' needs.

Cold-Climate Heat Pumps

Another area of increased sales comes from electrification of home heating. We are partnering with EVT to promote technologies that displace fossil fuel, to help our climate and our customer's costs. Cold-climate heat pumps provide customers with an alternative fossil-fuel-free method to heat their homes, as well as providing a more efficient way to cool the home in the summer.

EVT expects state households to take incentives associated with 3,000 new heat pumps per year. Based on our size, we expect that 76.6% of the heat pumps to be installed in our service area—about 2,297 heat pumps annually. These estimates were provided as part of the development of the VELCO long-term demand forecast.

A recent study conducted by Cadmus on behalf of the Vermont DPS concluded that, on average, cold-climate heat pumps use 2,085 kWh per year for heating and 140 kWh per year for cooling.

We conducted a sensitivity analysis for the added consumption and peak demand resulting from new heat pump installations. We modeled three growth scenarios, defined as follows:

Low Growth. The low growth scenario represents a 15% annual decrease in heat pump sales, starting with the EVT forecast of 2,297 in 2018. The observed trend in actual heat pump sales in Vermont between 2017 (4,161) and 2018 (3,000 as forecast by EVT) represents a decrease of 28%. We tempered the rate of decline because we do not expect this trend to continue, as we (and others) will be offering purchase incentives for heat pumps.

Baseline Growth. The baseline growth scenario uses EVT's forecast of 2,297 heat pumps per year in our service territory.

High Growth. The high growth scenario represents an increase in heat pump sales by 10% each year, starting with the EVT forecast of 2,297 for 2018.

All scenarios use the average annual values of 2,085 kWh for heating and 140 kWh for cooling.

The peak coincidence values represent the percentage of total possible heat pump load that coincides with the system-wide peak demand. We obtained these values from Efficiency Maine's 2014 Technical Reference Manual (TRM), which calculates energy and demand savings from various energy efficiency measures, including cold climate heat pumps. The TRM presents peak coincidence factors of 79.7% for winter and 10.7% for summer; peaks are defined as 1:00 PM to 5:00 PM in summer and 5:00 PM and 7:00 PM in winter. These values assume no control and include extreme examples of heat pumps running during the coldest days without a backup heating source. Although our summer peak is later in the evening, cooling load is highest during the hottest hours of the day and so we believe it reasonable to assume that the coincidence factor would not be higher for a later peak.

We obtained the average 1.0 kW heating demand and average 0.3 kW cooling demand from the aforementioned Cadmus study. Cooling only accounts for 2% of heat pump consumption so the impact on peak demand applies largely to the winter season.

To forecast Tier III performance relative to heat pumps, our sensitivity analysis includes the quantity of Tier III MWh under RES that would be met by added heat pumps alone for each year in the forecast. The presumed Tier III MWh contribution of a heat pump was computed using a weighted average of different types of heat pump units sold in our service territory and their corresponding Tier III values. These values are characterized by the Tier III Technical Advisory Group's 2018 Planning Tool, using the percentage of our non-fossil-fuel generation mix.

Table 4-10 summarizes the assumptions used in our sensitivity analysis and their corresponding sources.

Description	Value	Source
Average heating consumption	2,085 kWh per year	Vermont DPS Cadmus Study
Average cooling consumption	140 kWh per year	Vermont DPS Cadmus Study
Average heating demand	1.0 kW	Vermont DPS Cadmus Study
Average cooling demand	0.3 kW	Vermont DPS Cadmus Study
Heat pump Tier III value	27.12 MWh	Weighted average from sales

Table 4-10. Heat Pump Sensitivity Analysis Assumptions

The results of the sensitivity analysis are illustrated in Figure 4-4 through Figure 4-7.

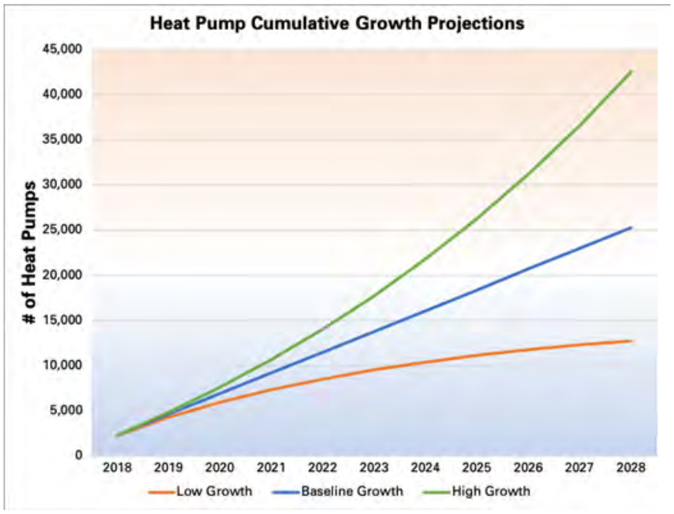

Figure 4-4. Cold-Climate Heat Pump Cumulative Growth Projections: 2018–2028

Figure 4-4 illustrates high, baseline, and low estimates for the quantity of added cold climate heat pumps in our service territory from 2018 until 2028. The cumulative values over the 10-year period are: 12,751 (low), 25,268 (medium), and 42,568 (high).

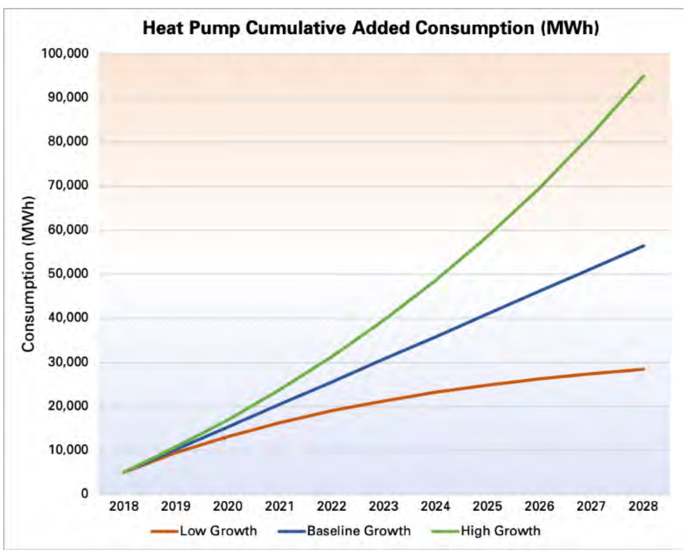

Figure 4-5. Cold-Climate Heat Pump Cumulative Added Consumption: 2018–2028

Figure 4-5 illustrates high, baseline and low projections for cumulative added MWh because of heat pump adoption through 2028. The projections are: 28,448 (low), 56,374 (baseline), and 94,970 (high).

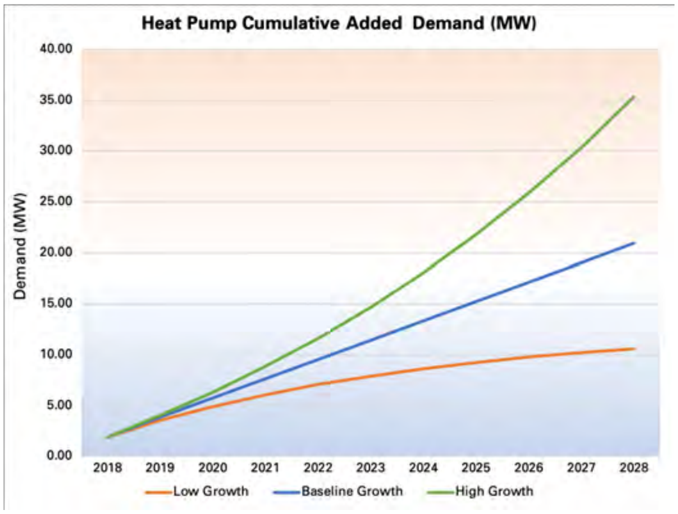

Figure 4-6. Cold-Climate Heat Pump Cumulative Added Peak Demand: 2018–2028

Figure 4-6 shows the cumulative added peak demand forecasted from the three different growth scenarios. The added demands are 10.6 MW (low growth), 20.9 (medium growth) to 35.3 MW (high growth) by 2028.

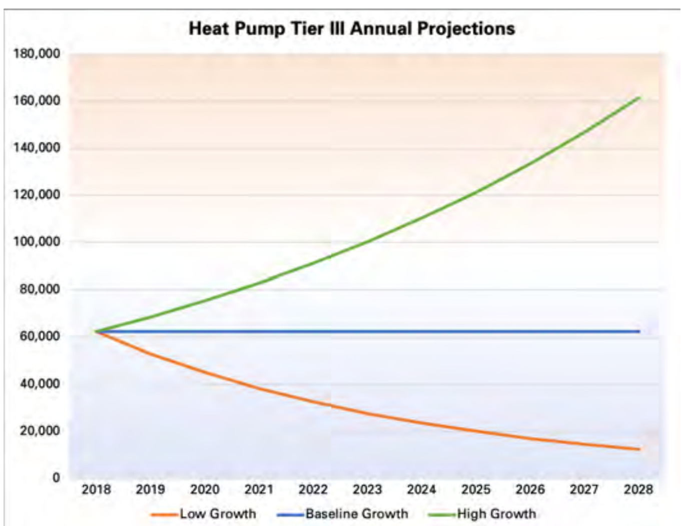

Figure 4-7. Cold-Climate Heat Pump Tier III Annual Projections: 2018–2028

Figure 4-7 illustrates high, baseline and low estimates for the annual Tier III MWh performance for added heat pumps. In the high growth scenario, heat pumps account for 56% of our total Tier III target in 2018, dropping to as low as 41% (because of a Tier III target increasing faster than the heat pump increase). In the low growth scenario, the percentage of the overall target met by Tier III ranges from 56% (2018) to 3% (2028).

Several conclusions and observations can be garnered from the analysis.

First, because of the lifetime emissions offset by cold-climate heat pumps, their adoption has a significant environmental benefit and thus supports our ability to meet Tier III targets. In the low growth scenario, heat pumps account for under 10% of our required carbon offset beginning in 2024, placing pressure on electric vehicle adoption as well as commercial and industrial (C&I) projects to make up the difference. Conversely, the high growth scenario consistently meets at least 40% of our carbon reduction targets.

Second, the analysis assumes no shared access or controls to reduce the impact of the heat pump consumption against the peak demand. We are pursuing shared access, and this control ability will improve to some extent the impact of any particular analysis outcome.

Regardless, under any analysis—even the high growth scenario—the added demand does not represent a significant peak demand addition to the overall transmission and distribution system. We have almost 300 distribution circuits; therefore, with any reasonable spread across these circuits, the individual peak contribution per circuit is still expected to be minimal even if 35 MW were added by 2028, as shown in the high growth scenario.

In any case, it will be important to effectively manage the added load through peak shaving. One challenge is that cold-climate heat pumps operate less efficiently at lower temperatures and so opportunities to shift heating load away from peak may be limited during the winter months. On the other hand, we expect many heat pump owners will have backup heating sources, as was the case for all units analyzed in the Cadmus study. This will help offset some of the added demand on very cold days when heat pumps consume most.

We observe that winter heating load dominates both the added load and consumption because of heat pump adoption. Thus, even though in the high growth scenario the cumulative added consumption equates to only 2.3% of our total projected sales, nearly all that impact occurs during the winter. That is the same time that solar generation is minimal, wholesale electricity prices are high because of a constrained natural gas supply, and the fuel mix of the grid is at its maximum CO_2 emissions. These considerations have important implications for the cost to serve each added MW, for which we are actively developing a comprehensive assessment tool.

To temper the high, and in light of our belief that the low assumption is excessively pessimistic, the baseline assumptions are used for cumulative consumption. (See “Consumption Trends” on page 4-34.)

Electric Vehicles

Transportation is the top source of carbon emission in Vermont. Transitioning from conventional combustion engines to electric vehicles will play an important role in offsetting statewide carbon emissions. This transition also will affect retail sales.

As described in Chapter 2: Innovative Customer Programs, we offer a variety of programs to encourage electric vehicle (EV) adoption. These programs include an EV charger incentive, EV charger as a service, unlimited charging, workplace contribution matches, public and workplace EV charging, and upstream rebates from manufacturers.

EV Home Charging

We believe that home charging will represent a major portion of charging activity for EV owners. Of critical importance, is the ability to manage loads during curtailments. Results from our pilot programs indicate promising responses with only a 2% opt-out rate.

Figure 4-8 shows a load curve for aggregate charging activity during a particular curtailment event that occurred between 4:00–8:00 PM. It illustrates the effectiveness of the automated control of chargers in our pilot.

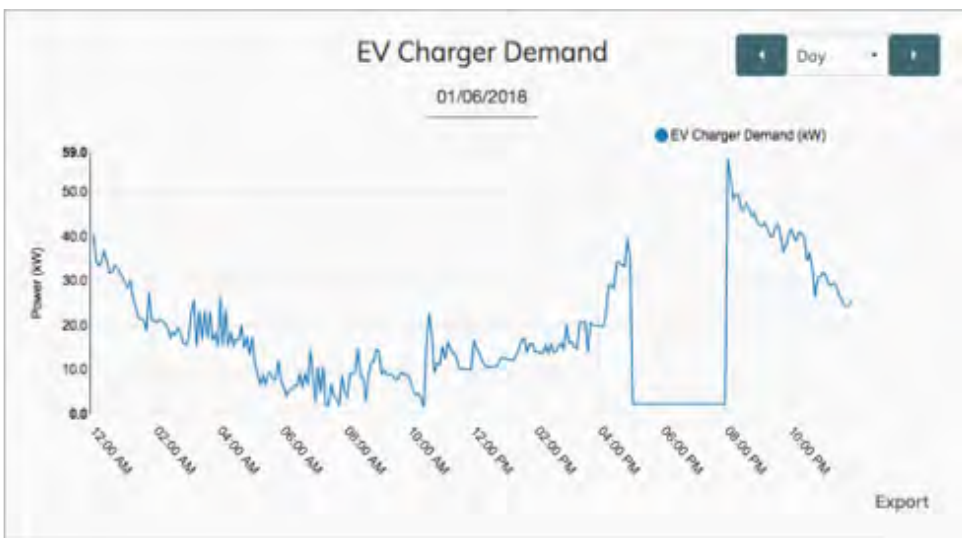

Figure 4-8. Electric Vehicle Tier III Annual Projections: 2018–2028

While these results are for a limited scale pilot, they suggest that customers are likely to cooperate with curtailments. Because the demand projection model in this report does not include an assumption that chargers will be controlled, it reflects a conservatively high demand assumption in all three projected EV volume ranges.

As an added potential value of controllable chargers, the demand associated with EV charging represents power that could be leveraged as a load-building tool in areas of high solar saturation. This would require networked chargers to be installed in businesses and other work and retail locations, allowing employees and the public to utilize these chargers during the middle of day as opposed to charging at night at home. For EV adoption to continue to grow, it must be convenient for customers; they must always have a charged EV when needed. Thus, simplicity and flexibility are critical when developing charging programs to utilize EVs as a grid resource.

Similar to heat pumps, we conducted a sensitivity analysis. For this sensitivity analysis EV sales are based on a range of projections issued in July of 2017 by VEIC. It is early in the adoption of electric vehicles, and, while there's high confidence that their proportion of the Vermont fleet will continue to grow, it is difficult to predict what trajectory the transition will take. VEIC used three ranges to identify various adoption cases. We evaluated the impacts those ranges could have, using those growth patterns, through 2028.

VEIC's forecasts cover a high range based on the level of vehicle adoption needed to reach the goals of Vermont's Comprehensive Energy Plan to achieve a 90% EV fleet. The medium range is based on a 60% EV fleet, and the low range is based on 40% EV fleet. In all scenarios, we assume that per share of Vermont total retail sales remains constant at 76.6%.

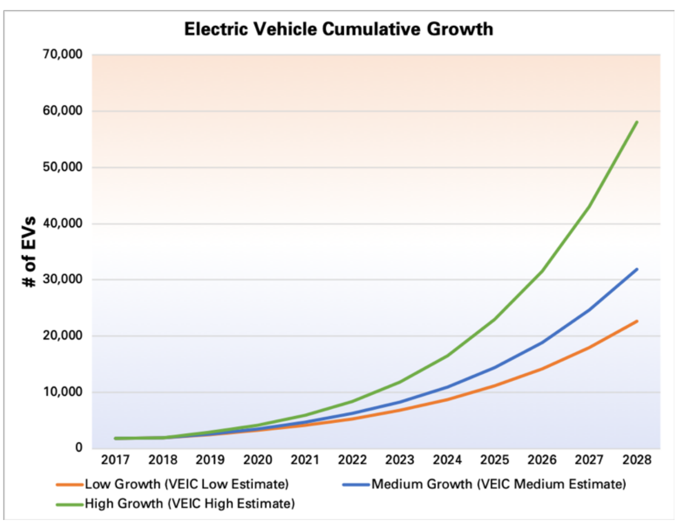

Figure 4-9. Electric Vehicle Cumulative Growth Projections: 2018–2028

Based on these models, Figure 4-9 shows a range of electric vehicle growth patterns over the study period. By 2028, the models result in a cumulative quantity of between 22,674 and 58,030 EVs in Vermont's fleet.

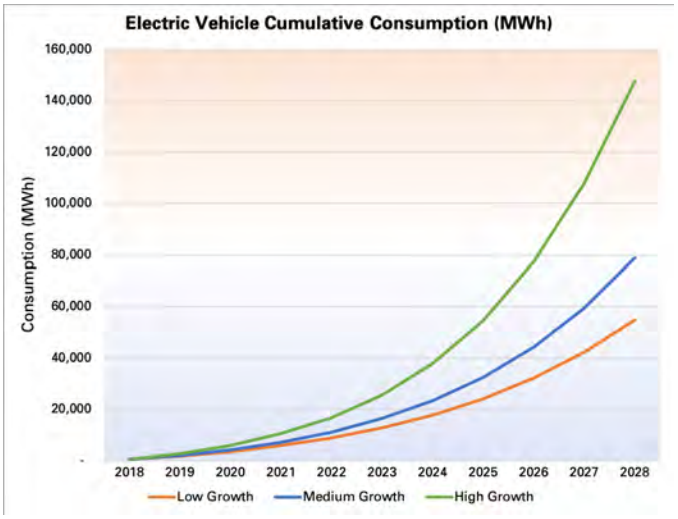

Figure 4-10. Electric Vehicle Cumulative Consumption: 2018–2028

Using Figure 4-10 shows the cumulative growth in MWh consumed by the modeled quantities of EVs over the study period. A blended averaged annual consumption of 2,470kWh is assumed for all vehicles. The forecasted effect on consumption associated with electric vehicles ranges from a low of 54,703 MWh to a high of 147,683 MWh by 2028.

Calculating consumption over time relies on a number of assumptions:

Average Electric Vehicle Miles Traveled (eVMT). In September of 2018, the Tier III Technical Advisory Group re-evaluated the characteristics of EVs, and issued an updated Technical Reference Manual (TRM). The study revealed that the average eVMT for EVs is 10,900 miles each year, and for PHEVs it is 6,908 miles each year.

Electrical Efficiency. The Technical Advisory Group TRM also reported an efficiency of 0.30 kWh per mile for all-electric vehicles (AEVs), and 0.34 kWh per mile for plug-in hybrid electric vehicles (PHEVs).

Proportion of AEVs to PHEVs. Because there is a significant difference in eVMT and electrical efficiency, the proportion between them must be factored into consumption calculations. The TRM relied on Vermont vehicle registration data to determine the proportion as of July of 2018. This proportion is roughly 33% AEV to 67% PHEV. The proportion has evolved over the past few years, with the percent of AEVs growing. The EVT model selected a growth path that would have approximately 50% AEVs by 2028. The increase from 33% to 50% over that period is depicted logarithmically in this analysis.

To estimate the average consumption of EVs each year, this model uses the quantities projected in the various volume ranges, multiplied by the weighted average of the consumption of AEVs and PHEVs as it evolves between 2018 and 2028.

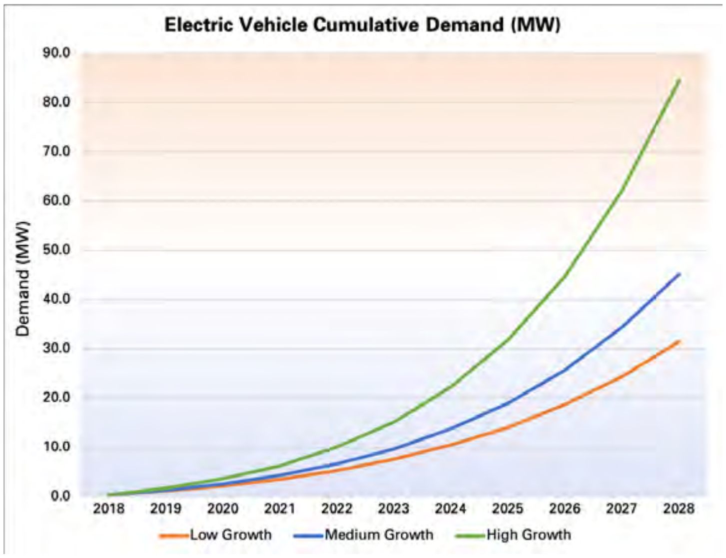

Figure 4-11. Electric Vehicle Cumulative Demand: 2018–2028

In addition to sensitivities of added retail sales we performed similar peak coincident demand sensitivities as done for the heat pumps. Figure 4-11 projects the uncontrolled, coincident peak demand for the three sensitivities performed. Assumptions include an average of 30% coincidence with peak, and an average demand of 5kW. The annual demand is calculated based on the number of EVs multiplied by the Average Demand multiplied by the Average Coincident Peak.

With over 150 network residential chargers currently operating in our Pilot platform, we were able to derive the actual peak coincidence factor. Based on aggregate load across all chargers in the program, the maximum peak coincidence factor observed in 2018 is 30%.

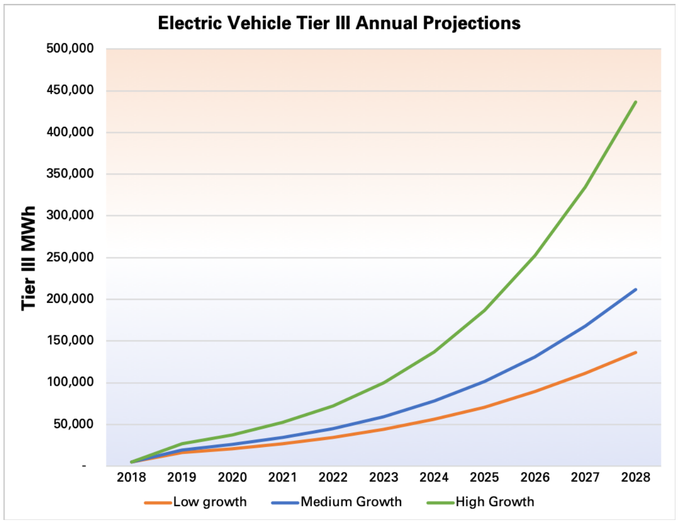

Figure 4-12. Electric Vehicle Tier III Annual Projections: 2018–2028

Figure 4-12 illustrates high, baseline and low estimates for the annual Tier III MWh performance for added EVs. The average blended MWh value of EVs changes from year to year as the proportion of AEVs to PHEVs changes starting at 66% PHEVs in 2018 and dropping to 50% by 2028. In the high growth scenario, EVs account for 436,379 MWh by 2028, 211,902 in the medium growth scenario, and 136,538 in the low growth scenario.

In terms of cumulative consumption, the high scenario shows an optimistic addition of 147,683 MWh over 10 years. This model is really illustrative to reflect what would be required to support the State's aspiration of 90% carbon free by 2050, but given what we know today, this seems like a stretch goal that would require significant acceleration beyond the planning period.

With approximately 2,300 EVs on the road today, and a manufacturing industry that has a relatively long product cycle and has not yet committed to an affordable product line that addresses the majority of driver needs, it is difficult to envision that model taking hold within the planning period.

With these factors in mind, we do believe that there will be an inflection point in the industry, and customer adoption, at some point in the near future, aided by GMP's and Vermont's concerted efforts to encourage this transition. This led us to conclude that the low estimates are overly pessimistic. We believe the baseline scenario is the most realistic for the planning period. As such, the baseline scenario of 78,853 MWh is used in Table 4-14 (on page 4-34) that summarizes load impacts. We note that even if the high scenario were used in this planning period, the effect in these immediate years would be negligible because under any scenario adoption will accelerate in the out years.

Commercial and Industrial

In partnership with Efficiency Vermont, we have been working directly with larger commercial and industrial customers to reduce their carbon footprints while helping reduce operating costs and improve efficiency. In some instances, this involves electrification of an existing process that was formerly powered with fossil fuel.

In Tier III parlance, these projects are 'custom measures'. These measures are characterized for their fossil fuel offset, and resulting Tier III MWh value based on a set of calculations that factor in the quantity of fuel being offset, the efficiency of the legacy and new solution, the life of the measure, and our average proportion of non-fossil fuel-sourced energy in its portfolio. This is distinct from Tier III 'prescribed measures', such as heat pumps and EVs, which have pre-determined Tier III MWh values calculated by the Tier III Technical Advisory Group, and maintained in an annually updated Tier III Planning Tool.

Work with our commercial and industrial customers involving strategic electrification has included: the construction of electrical service to offset diesel generators, pumps, and compressors at quarries, maple sugar operations, ski areas, and manufacturers; air and water heating; and industrial processes.

Recent project examples have included:

- Supporting the replacement of propane-fired heating for a municipal skating rink, offsetting approximately 20,000 gallons of diesel per year.
- Extending 3-phase service to offset a generator at a manufacturer of slate roofing tiles, offsetting over 10,000 gallons of diesel per year.
- Collaborating with Efficiency Vermont to support a project that offsets propane heating in a year-round tomato greenhouse, that leverages radiated heat from high-pressure sodium lighting, combined with an insulating and light filtering curtain, offsetting over 42,000 gallons of propane per year.
- Replacing diesel compressors for snowmaking at three ski areas, offsetting a combined total of over 60,000 gallons of fossil fuel per year.

Unlike the models for heat pumps and EVs, which are based on unit quantities, modeling the impact of energy transformation projects on consumption and demand depends on a projection of the volume of projects and their presumed Tier III value. For this reason, we start with an evaluation of Tier III MWh growth, and use those projections to model consumption and demand impacts.

Figure 4-14 and Figure 4-15 show the results of a sensitivity analysis for the impact of C&I projects on consumption and demand. We modeled two scenarios: high growth and low growth.

High Growth. Assumes year-over-year increase in Tier III MWh program value starting at 150% of the previous year's performance in 2019 and decreasing 10 percentage points each year until 2024, after which the Tier III MWh performance falls below 100% of target and drops by 10% each year through 2028.

This forecast is based on several factors:

- In 2017, the first year of C&I outreach, we supported projects that achieved over 92,000 Tier III MWh. This was from just 4 projects.
- In 2018, our commercial and industrial program is expected to achieve approximately 52,000 MWh of Tier III MWh from 20 projects.
- Performance during both years was achieved with minimal external partnerships and a single full-time equivalent (FTE).
- During 2018, we crafted a collaborative partnership with EVT, an educated fleet of distribution designers looking for opportunities, and two additional full-time employees working on the program.

Low Growth. Assumes we match the 2018 projected total of 51,500 Tier III MWh in each year through 2028.

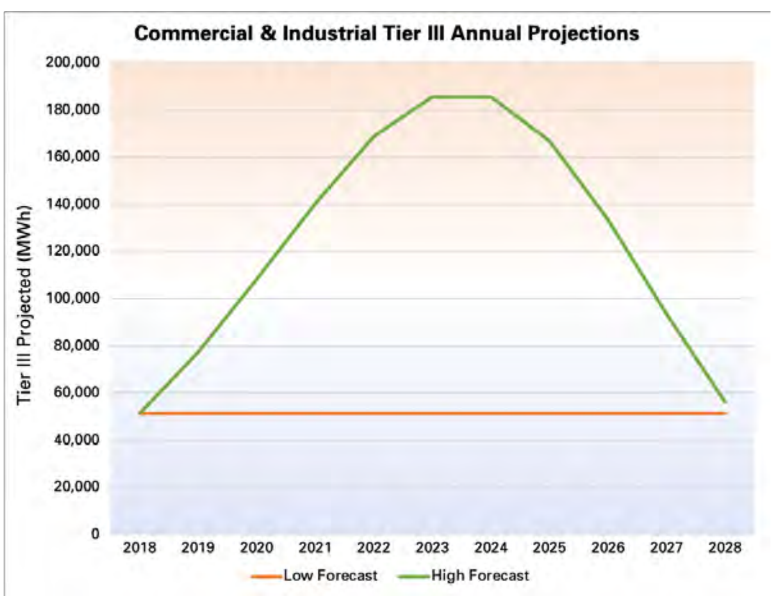

Figure 4-13. Electric Vehicle Tier III Annual Projections: 2018–2028

Figure 4-13 illustrates the trajectories of Tier III performance for these two models. The high and low estimate for Tier III MWh value each year for C&I custom projects, range from 51,500 MWh (the value in each year of the low forecast) to 185,585 MWh (maximum of the high forecast). These represent approximately 49% and 14% of our total 2028 Tier III target, respectively.

For the high and low scenarios, we calculate consumption and demand using the following assumptions based on observations from existing customers:

- Our custom Tier III projects garnered 142,281 MWh of Tier III credit between 2017 and 2018. Those projects are predicted to consume 5,398 MWh per year. This gives us a ratio of consumption added per Tier III MWh of approximately 0.038 MWh.
- The average of 1,500 hours of operations each year is arrived at based on typical operations of 2,000 hours per year, reduced by a factor to account for seasonal operations, like ski areas and gravel quarries.
- A 30% coincidence with peak. While it is early in the Tier III C&I program, this assumption takes a conservative approach to estimating peak coincidence. Some of the considerations that go into this estimate include the fact that many participants opt into the curtailable load rider program, which commits participants to curtail load specifically during peak events. In additional, many of these businesses have operating hours that end by 4:00 PM, missing typical Regional Network Service and Forward Capacity Market peak hours.

Although these are rough estimates only given the uncertainties created in this type of program, we expect that there will be enough natural variation among C&I customers to achieve a balanced demand curve.

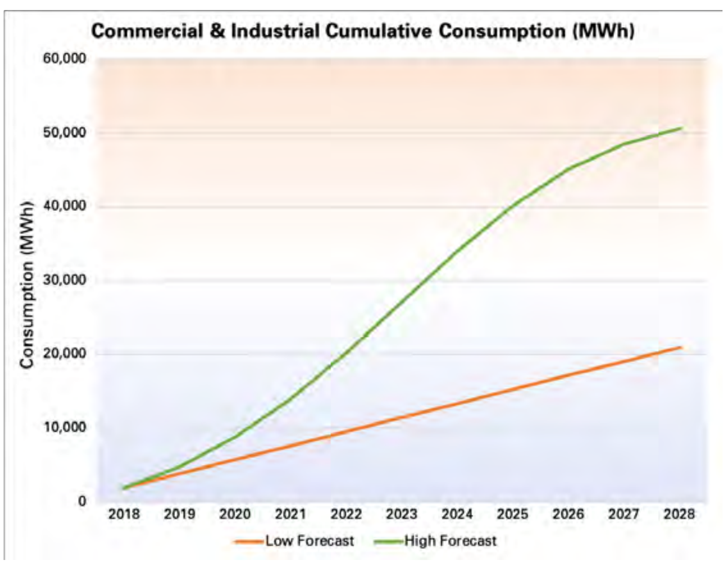

Figure 4-14. Commercial and Industrial Cumulative Consumption: 2018–2028

Figure 4-14 illustrates the resulting estimates for aggregate C&I consumption that would result from the high and low forecasts. Consumption tops out at 21,961 MWh for the low scenario, and 50,604 MWh for the high scenario, by 2028.

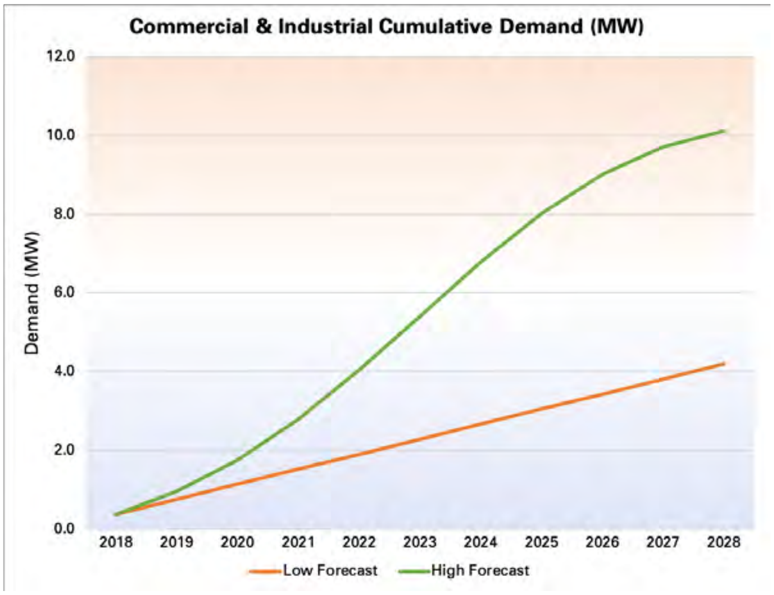

Figure 4-15. Commercial and Industrial Cumulative Demand: 2018–2028

Based on calculated consumption, and the assumed 30% coincident peak, Figure 4-15 illustrates the aggregate impact of C&I projects on demand for the two performance ranges. The aggregate demand for the high performance range is 10 MW, while the low range is projected to demand 4 MW by 2028.

While the widely varying results for C&I between 2017 and 2018 suggest divergent forecasts, there is reason to believe that the program will experience a period of growing performance for at least the next few years. The scenario carried forward to Table 4-14 (on page 4-34) assumes a baseline level of performance that is the average of high and low scenarios, which results in a forecast of 35,782 cumulative MWh over the next 10 years.

Tier III Implications

Overall Tier III performance is illustrated by combining the performance assumptions for the heat pump, EV, and C&I models. Our Tier III performance has financial, operational, and environmental implications. Tier III performance will also impact aggregate consumption and demand of our operations.

The Tier III program drives financial costs because of the manpower, promotional activities, and incentives that have to be funded to support the program. These costs are offset by revenue from the increased MWh sales that result from strategic electrification. Anther financial dynamic is the Alternate Compliance Payment, which is the regulatory penalty assessed for missed Tier III targets. ACP started at $60 per MWh in 2017, and escalates based on inflation.

The environmental implications get to the heart of why the RES exists. Each Tier III project completed will reduce Vermont's carbon footprint for the long term, by replacing a process that consumes fossil fuel with an alternative that eliminates carbon emissions.

Finally, Act 56 establishes a relationship between Tier II and Tier III by allowing Tier II MWh to satisfy shortfalls in Tier III performance.

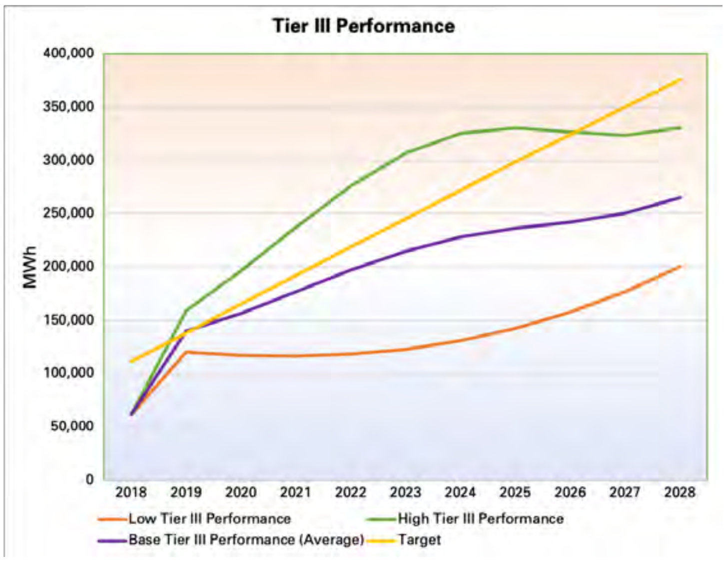

Figure 4-16. Tier III Performance: 2018–2028

Figure 4-16 illustrates a variety of trajectories for overall Tier III performance through 2028. The low model combines the low performance ranges from each of the Tier III programs: heat pumps, EVs, and C&I. The high model uses the high C&I estimate, combined with the medium performance ranges for heat pumps and EVs. This reduces the risk of magnifying the highs of multiple models. The Base model illustrates the average of the high and low Tier III performance ranges. Figure 4-16 includes the Tier III Target to show how each performance model relates to the regulatory mandate.

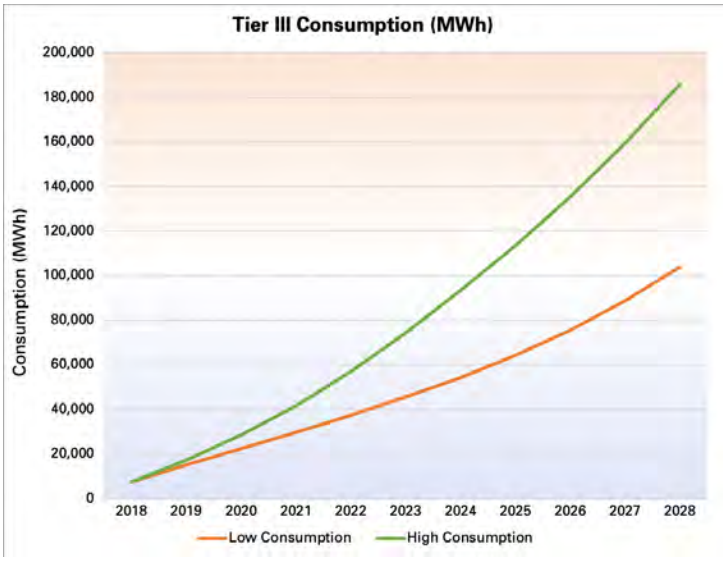

Figure 4-17. Tier III Consumption: 2018–2028

Figure 4-17 illustrates the cumulative aggregate consumption associated with the low and high models. The high model tops out at 185,831 MWh, while the low model tops out at 104,112 MWh.

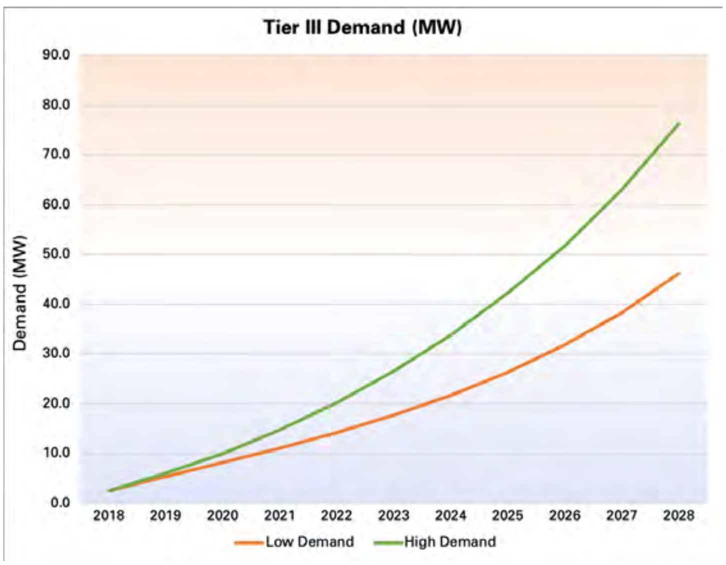

Figure 4-18. Tier III Demand: 2018–2028

Figure 4-18 illustrates the high and low estimates for overall our Tier III cumulative demand. The high model tops out at 76 MW, while the low model tops out at 46 MW.

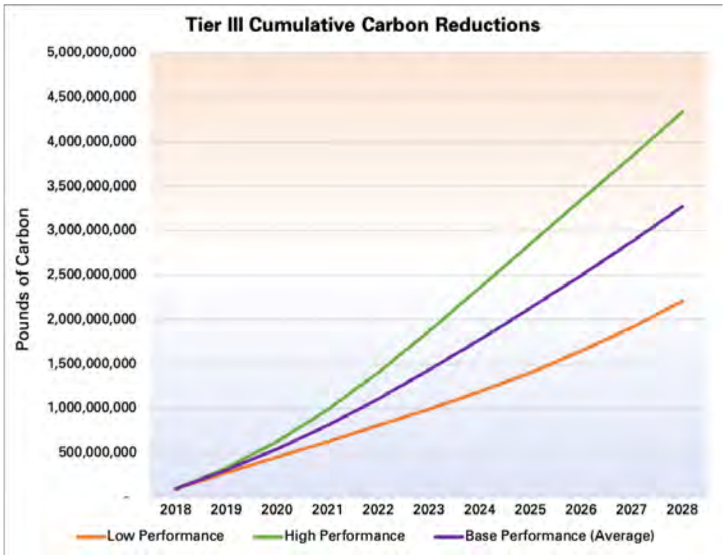

Figure 4-19. Tier III Cumulative Carbon Reductions: 2018–2028

Figure 4-19 illustrates the cumulative carbon Reductions. The high model achieves nearly 4.5 billion pounds of CO_2 reductions by 2028, while the low model approaches 2.5 billion pounds of CO_2 reductions in that timeframe.

Tier III Program Costs

The achievement of Tier III targets comes with associated costs. These costs are generated from a combination of the operations and maintenance costs associated with program administration, program promotion, the incentives that we will provide to customers to drive adoption of these energy transformation initiatives, and the cost of Tier II RECs, which can be retired to substitute for Tier III MWh.

Operations and Maintenance Costs. Labor costs represent the largest portion of program costs for Tier III. Costs reported for the 2017 Tier III program were based on 50% of the staff that supports our Energy Innovation Center. Fifty percent of average productive hours were multiplied by the fully loaded hourly rate to come up with cost. For the sensitivity analysis, all cases assume an annual one-FTE reduction of EIC headcount beginning in 2020. The fully loaded rate is escalated by 2% per year to account for inflation.

Promotion Costs. Costs in 2017 were $160,000, and 2018 promotional costs are expected to by $280,000. The budget for 2019 is $220,000. The sensitivity analysis for all ranges starts with the 2019 budget, and escalates annually by 5%.

Incentive Costs. we have a short history of how incentives depict the valuation of Tier III MWh. 2018 cost per Tier III MWh was $13.59. For purposes of the sensitivity analysis, we assumed that this would escalate by 5% per year.

Tier II RECs. Because Tier II RECs can be retired to offset MWh shortfalls in Tier III, they can represent a cost of Tier III MWhs missed in any year. The value of Tier II RECs is projected using Regional Class I RECs as a proxy. Table 4-11 shows the annual cost projections for these RECs.

Year	Cost
2019	$9.00
2020	$13.50
2021	$17.00
2022	$17.50
2023	$16.50
2024	$16.00
2025	$15.50
2026	$15.00
2027	$15.00
2028	$15.00

Table 4-11. Annual Regional Class I REC Costs

Three ranges are used for the sensitivity analysis, based on Tier III performance.

Low Tier III Performance. This range uses the Tier III rollup model that reflects low performance. It is based on the low range being achieved each year in each of the three programs—cold climate heat pumps, EVs, and C&I. This range assumes the Tier III target is missed each year, and the shortfall is assumed to be covered by Tier II RECs.

Baseline. This range models costs if Tier III targets are achieved each year.

High Tier III Performance. This range uses the high range from the Tier III rollup. It shows Tier III targets being met through 2026. In 2027 and 2028, Tier II RECs are used to cover the shortfall.

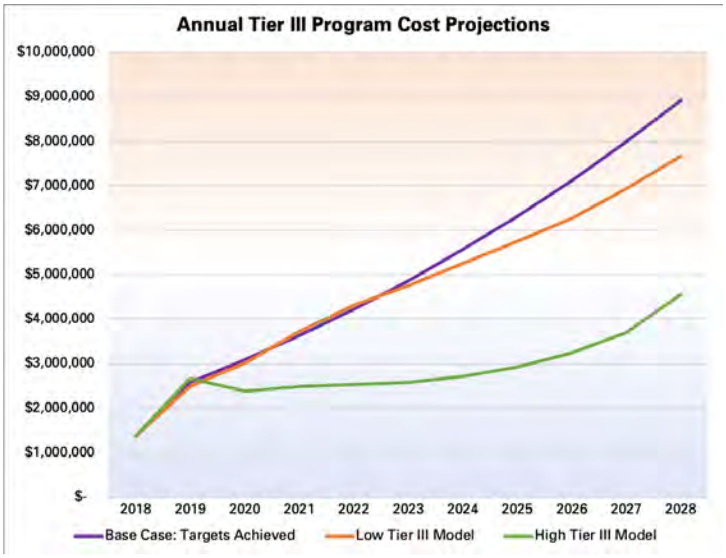

Figure 4-20. Tier III Annual Cost Projections: 2018–2028

Figure 4-20 shows the projected program costs under the three separate scenarios.

Given the divergent cost paths in this analysis, and the complex relationship between heat pump, EV, and C&I forecasts, the averaging of these models into a baseline scenario is likely to provide the most reasonable prediction of future performance of the overall Tier III program and associated costs. Table 4-12 illustrates annual costs under this scenario for the period from 2018 until 2028.

Year	Total Cost
2018	$1,369,862
2019	$2,583,401
2020	$3,086,712
2021	$3,629,185
2022	$4,221,756
2023	$4,864,612
2024	$5,563,637
2025	$6,316,706
2026	$7,116,219
2027	$7,986,585
2028	$8,923,977

Table 4-12. Tier III Cost By Year Baseline Scenario

Cooling and Heating Degree Days

Retail sales can also be forecasted against weather normalization. To do this, weather trends are analyzed over various periods of time. When this analysis was conducted on our service area, it was observed that the number of heating degree days has decreased over time, resulting in warmer winters. Concurrently, the number of cooling degree days has increased over that same time period, meaning that the summers are becoming warmer.

Figure 4-21 shows this trend over the past 30 years.

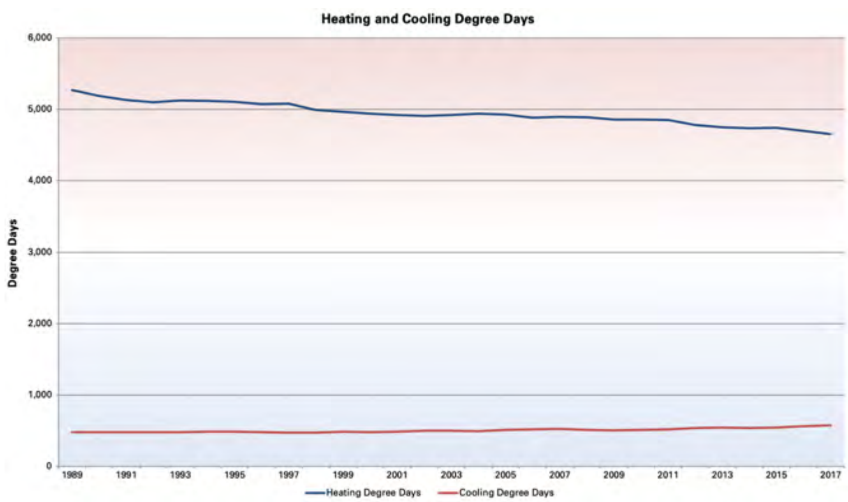

Figure 4-21. Trends in Heating and Cooling Degree Days

Heating degree days are trending down by about 0.4% annually, while cooling degree days are trending up by 1.0% annually. These trends are similar to the EIA's data for all of New England.

Table 4-13 shows the impact of these warming trends upon our forecast.

Year	Incremental (MWh)	Cumulative (MWh)
2018	1,097	1,097
2019	2,214	3,311
2020	549	3,860
2021	619	4,479
2022	671	5,150
2023	736	5,886
2024	805	6,691
2025	860	7,551
2026	930	8,481
2027	1,014	9,495
2028	1,089	10,584

Table 4-13. Incremental Impact of HDD and CDD Trends on Retail Sales Forecast

Note that the effect of heating and cooling degree days is incorporated in the growth found in Table 4-9.

CONSUMPTION TRENDS

All of the factors impacting load have a cumulative effect over the next ten years that shows downward pressure. Energy efficiency, appliance standards, and solar net metering all reduce load; economic and household growth, cold-climate heat pumps, and electric vehicles all increase load but not at a projected pace to offset reductions. Projected over ten years, the cumulative totals of these factors have a significant effect on load, and show how load is projected to decrease over the subsequent decade.

Load Affecting Factor	Cumulative Effect (MWh)
Cold-Climate Heat Pumps	56,374
Economic & Household Growth	132,272
Electric Vehicles	78,853
Electrification	35,782
Energy Efficiency	–237,609
Solar Net Metering	–93,628
Total	**-27,956**

Table 4-14. Cumulative Effect of Load Reducers and Increasers: 2018–2028

Table 4-14 details the ten-year cumulative total of each of these load increasing and decreasing factors, then their overall total effect on load. For those factors for which we conducted sensitivity analyses (EV, heat pumps, and C&I electrification), we used the baseline average result.