Chapter 2 - Burlington's Demand for Electricity

Burlington Electric Department ("BED")'s 2020 Long-Range Forecast for this IRP informs BED's resource planning to meet the forecasted total annual consumption of electric energy. This is referred to as the system energy forecast and is expressed in terms of kilowatt-hours ("kWh"), megawatt-hours ("MWh"), or gigawatt-hours ("GWh"). This system energy forecast is made up of forecasts of electric sales to consumers, BED company use, and associated distribution and transformer losses. Together, these forecasts comprise the energy requirements that must be supplied by BED to meet customer needs.

BED's projected load requirements are also based on the expected maximum rate of use of electricity ("peak demand"), measured in kW or MW. If BED does not successfully generate or purchase enough generation from other resources to transmit and distribute to its customers to meet peak demand, customer loads could need to be curtailed to prevent overloads and/or system failure.

Table 1 shows the BED energy and demand forecast, after accounting for the effects of future energy efficiency and behind-the-meter generation.

Table 1: Annual Energy Requirements & Peak Demand, 2019-2039

	2019	2024	2029	2034	2039	CAGR
Residential	81,171	82,702	87,053	95,864	107,315	1.4%
Commercial & Industrial	246,572	252,147	248,226	242,255	238,453	-0.2%
Street Lighting	2,160	1,976	1,792	1,608	1,424	-2.1%
Losses & Co. Use	6,499	6,675	6,622	6,518	6,475	0.0%
Total Energy Use (MWh)	336,402	343,500	343,693	346,245	353,667	0.3%
Peak Demand (MW)	64.5	65.4	65.4	65.4	66.0	0.1%

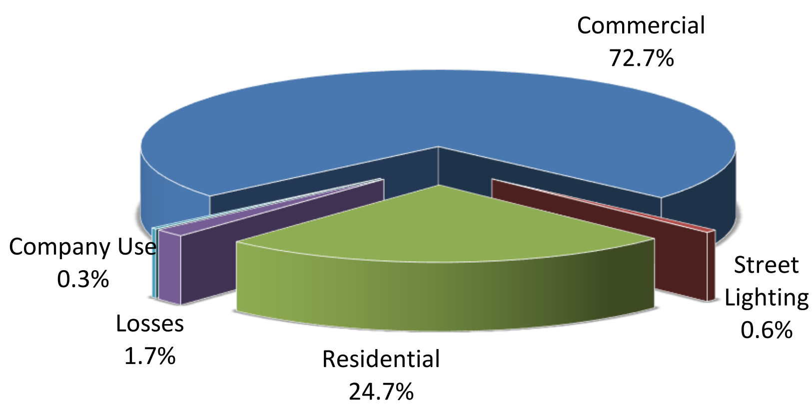
Over the next 20 years, base case system energy requirements average 0.3% annual growth with annual customer growth of 0.5%. Peak demand increases 0.1% annually over this period. In comparison, since 2010, system energy has declined on average 0.5%annually and peak demand has declined 0.1% per year. Positive forecasted energy requirements are largely the result of expected electric vehicle ("EV") sales' growth in the second half of the forecast period.

Background

BED provides electricity in its service territory of approximately 16 square miles, and the Burlington International Airport ("Airport"), located in South Burlington. BED is the third largest utility in Vermont, accounting for 6.1% of total retail kWh sales.

BED currently serves about 17,200 residential and 3,880 commercial customers. These customers required 341,204 MWhs of electricity during 2018 including roughly 334,417 MWh in sales and distribution losses and company (i.e. BED) use making up the remainder. The commercial customers account for the largest share of electricity use, with nearly 73%of the total (Figure 1). The residential class accounts for roughly 25%of the total energy requirements.

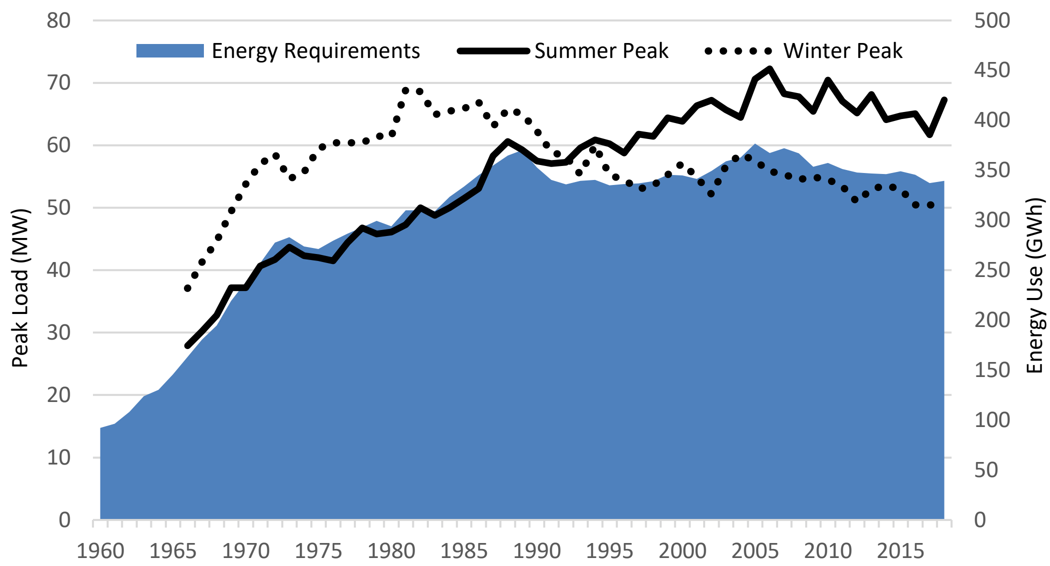
Figure 1: 2018 System Energy Requirements



Over the last 10 years, total kWh sales have been declining at a rate of 0.8%per year. This is a trend throughout Vermont and across much of the country. Utility efficiency programs have suppressed demand in all sectors, and the federal energy efficiency programs like Energy Policy Act of 2005 ("EPAct2005") and Energy Independence and Security Act ("EISA 2007"), have also played a key role in reducing energy use over this period. Figure 2 provides the long-term electricity use trends in Burlington. Overall, total electricity use in Burlington has increased by 2.3%per year since 1960, although this growth has not been uniform over time.

In the years prior to 1973, the utility industry benefited from a persistent decline in real electricity prices as this allowed for promoting "all electric living." Predictably, the proliferation of electric appliances and the use of electricity for space and water heating in the residential sector caused consumption per household in Burlington to rise dramatically. Electric space heating, virtually unheard of in 1960, was used in over 1,200 Burlington households by 1970. Total system energy use increased at a rate of 9.0%per year during this period.

Figure 2: Historic System Peak & Energy Requirements



Rising oil and coal prices and the delayed startup of Vermont Yankee contributed to higher power costs in the region by the early 1970s. By the end of 1973, the nation was in the midst of an energy crisis, and the era of aggressive load building was coming to an end. In New England, the next two decades would be characterized by sharply higher retail prices for electricity and moderating demand for power by customers. Utility regulators embraced the idea of seasonal rates, and utilities began offering conservation and load control programs.

Since 1989, the leveling off of electricity use can be attributed in large part to more vigorous demand-side management activities by the utility, but also has roots in fundamental demographic changes and changing economic conditions.

In 1993, Burlington's annual peak demand occurred in July. This was significant, since it was the first time BED had its annual peak demand occur during the summer. Beginning in the mid-1980s, the decline in the winter peak demand was attributed to the decline in the use of electricity for space heating and water heating. The summer peak load continued to rise, driven by the increasing use of air conditioning in the residential and commercial sectors. More recently, we have experienced a decline in both winter and summer peak demand, which can be attributed to energy efficiency programs and standards.

Burlington continues to be a summer peaking utility with significant load variation throughout the summer months; this variation is largely driven by air conditioning. Figure 3 shows the 2018 hourly net demand. Net demand – the total electric demand in the system minus customer-owned behind-the-meter generation – represents the demand that BED must meet with resources, contracts, or purchases from the ISO-NE spot market The summer of 2018 was much warmer than normal, with the maximum hourly demand occurring on July 2. The highest demand for electricity during the winter months occurred on January 15.

Figure 3: 2018 Hourly System Net Demand

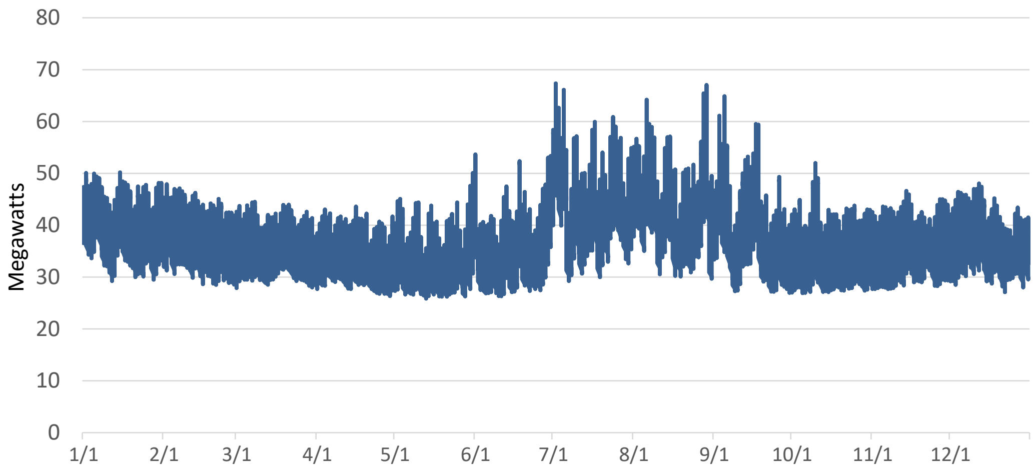
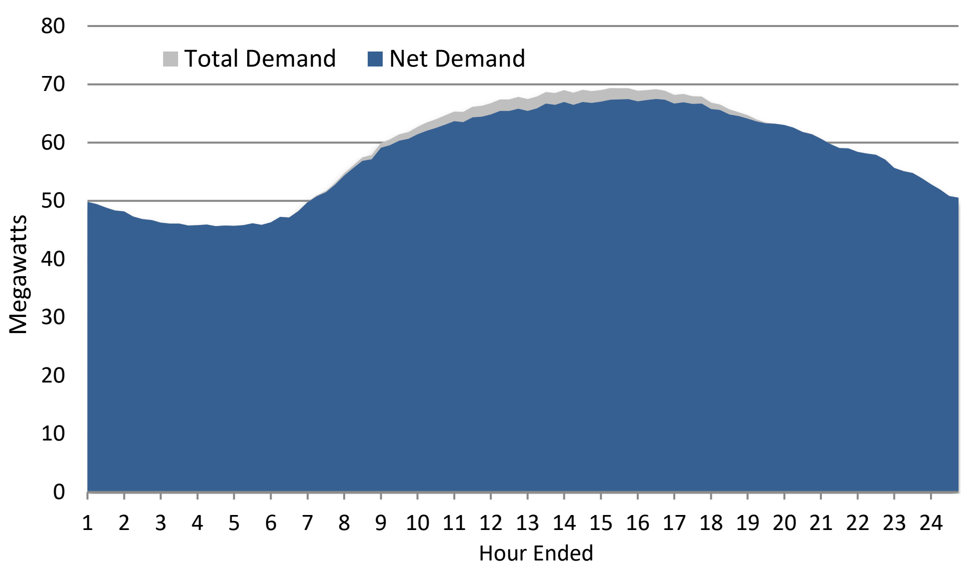


Figure 4 provides a view of the City's hourly demand on the summer peak day in 2018. The summer peak day is characterized by one daily peak period with load rising gradually until the early afternoon, before gradually declining after 5 pm. The summer peak demands occur most often between 2 and 5 pm, on days when the average daily temperature exceeds 80 degrees Fahrenheit. Burlington averages about 3-4 days per year with average daily temperature higher than 80 degrees Fahrenheit. The summer of 2018 was one of the warmer summers on record, with average daily temperatures exceeding 80 degrees on 12 different days, and the average temperature reaching a record level (88 degrees Fahrenheit) on the peak day.

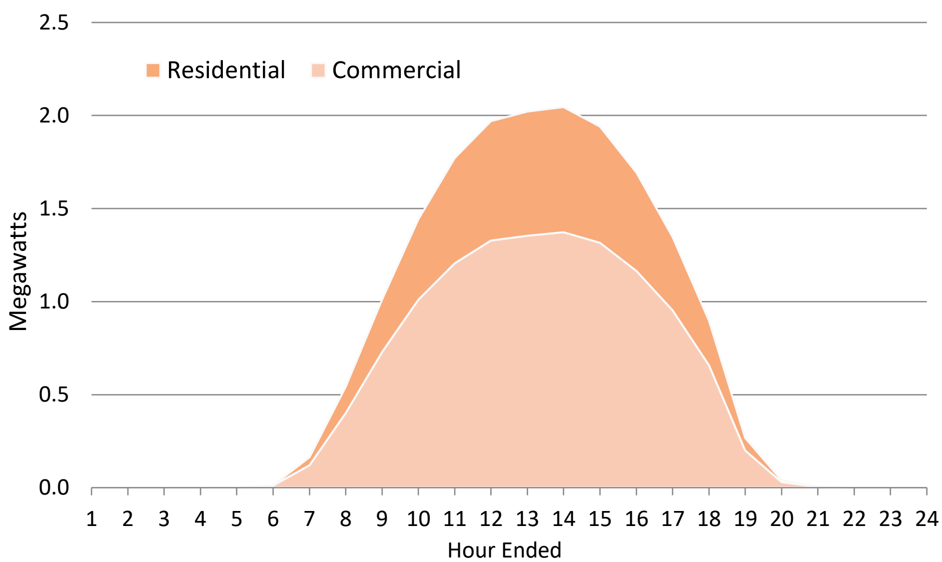
Figure 4: System Demand on July 2, 2018 (Peak Day)



The impact of behind-the-meter solar generation on peak demand is a function of the timing between solar generation and system hourly demand. On July 2, the maximum system demand reached 69.2 MWs at hour ended 3:00 pm. The maximum ***net*** demand (excluding the customer behind-the-meter generation) was 67.3 MWs, also occurring at hour ended 3:00 pm. The behind-the-meter solar generation reduced the system peak demand (-1.9 MW) but did not shift the peak hour.

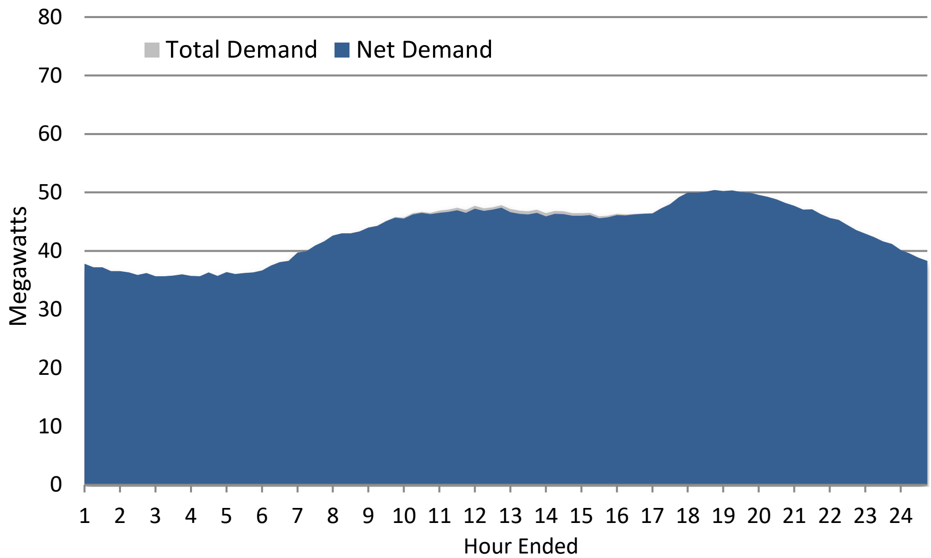
Figure 5 shows the total customer owned behind-the-meter solar generation in Burlington on that day. As the amount of solar generation on BED's system increases, the net peak demand will eventually shift to later in the day. On this day, it would have taken close to 8 megawatts of behind-the-meter solar generation to shift the peak hour to 7:00 pm.

Figure 5: Behind-The-Meter Solar Generation on July 2, 2018



During the winter months the system load increases rather abruptly in the morning, peaking by around noon, then drops slightly before increasing again after 4:00 pm, peaking around 6:00 or 7:00 pm. Solar PV capacity has no impact on the winter peak demand since the winter peak is in the evening hours when there is no solar generation.

Figure 6: System Demand on January 15, 2018 (Winter Peak Day)



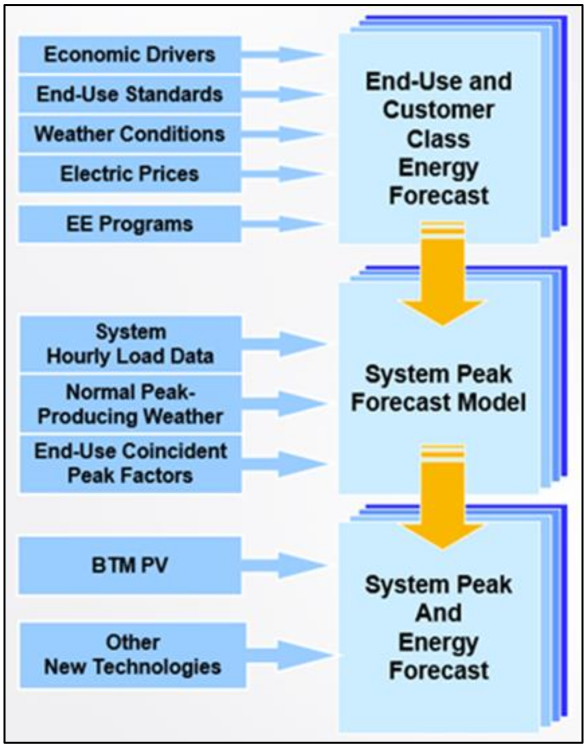
Forecast Approach

BED contracted with Itron, Inc. ("Itron") to develop a 20-year energy and demand forecast to support the IRP planning process.[1] The forecast was developed using the same methodology that was approved in BED's previous IRP, except that impacts from EV adoption was included in this forecast.

The system energy requirements and peak demand forecasts are derived using a "build-up" approach. This entails first developing residential and commercial forecast models that are then used to isolate heating, cooling, and non-weather sensitive end-use energy projections. End-use energy forecasts combined with peak-day weather conditions then drive system peak demand. Energy, peak, and hourly load profile forecasts are combined to generate a system baseline hourly load forecast. The baseline hourly load forecast is then adjusted for the impact of technologies including solar, EVs, and cold climate heat pumps. Figure 7 outlines the modeling approach.

[1] Itron's detailed report comprises Appendix A.

Figure 7: BED Long-Term Build-Up Model



The residential and commercial forecasts were based on Itron's Statistically Adjusted End Use ("SAE") modeling framework, which combines the end-use modeling concepts with traditional regression analysis techniques. One of the traditional approaches to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, the strength of econometric models is that they are well suited to identify historical trends and to project these trends into the future.

In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are driving energy use. By incorporating end-use structure into an econometric model, the SAE modeling framework captures the strengths of both approaches. For instance, by explicitly introducing trends in equipment saturation and equipment efficiency levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time and identify end use factors driving those changes.

The SAE models leverage the U.S. Energy Information Administration's ("EIA") Sector-Level End Use Saturation and Efficiency Forecast for the Northeast Region as well as information specific to Burlington. The result is a long-term forecasting framework that captures long-term structural changes, short-term driving factors of usage levels such as economic activity, electricity price, and weather, and their appropriate interactions.

Furthermore, the framework facilitates the disaggregation of the sector level sales forecasts into end use-level forecasts in support of further evaluation.

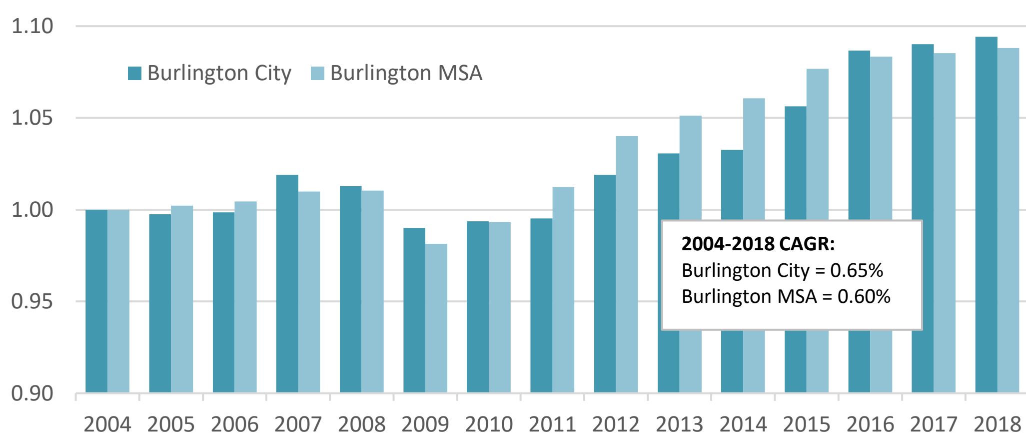
The residential and commercial forecast models were based on "reconstituted" monthly sales, where all behind-the-meter solar PV impacts were added back to the monthly billed sales. After the individual monthly forecasts were produced, the system load shape was adjusted to account for the impacts of existing and future behind-the-meter generation and EV adoption.

Base Case Assumptions

Several economic indicators were used as independent variables (forecast "drivers") in our energy forecasting process. For the residential class, income, population and number of households in the region were used as drivers. In the commercial sector, gross metro product and employment were used as drivers. These drivers are consistent with ones used in our previous IRP forecasts. The economic forecasting firm Moody's Analytics was the source for the forecast of these economic drivers. Moody's Analytics is a highly reputable firm in the macroeconomic forecasting arena with specialized competency in doing the work.

Economic forecasts were not available for the local area (Burlington City), so BED relied on forecasts for the Burlington/South Burlington Metropolitan Statistical Area ("MSA") as a proxy. The economies of Burlington City and the broader metropolitan area tend to be integrated and track fairly closely. For example, Figure 8 compares the employment growth rates for the City of Burlington and the Burlington MSA for the recent 15-year period. The year-to-year change and overall growth over the period was very similar.

Figure 8: Total Employment Growth by Region (2004 = 1.0)



BED's projected data is weather normalized. Historic daily weather data was available for the Burlington weather station for the period January 1978 to December 2018. Normal degree days were calculated using this data from the 20-year period 1999 to 2018. The heating and cooling degree variables were customized (from the typical 65-degree reference) separately for the residential and commercial sectors by evaluating daily kWh use and daily temperature. For the residential sector, cooling degree days were calculated with a 65-degree base, and heating degree days with a 60-degree base. The degree days were customized for the commercial sector in the similar fashion.

The residential sector incorporates saturation and efficiency trends for seventeen end uses. The commercial sector captures end-use intensity projections for ten end-use classifications across ten building types. The models rely on an analysis of EIA's Annual Energy Outlook forecast performed by Itron. EIA saturation projections were adjusted to reflect BED appliance saturation surveys and the mix of multi-family and single-family homes in Burlington. Care must be taken not to "double count" energy efficiency program impacts when using a methodology like SAE that accounts for efficiency trends on its own. To avoid double counting, efficiency savings projections were adjusted to reflect future efficiency savings embedded in the baseline sales forecast. The efficiency adjustment factors for each sector are estimated by incorporating historical efficiency savings as a model variable. For example, in the residential model, the efficiency savings variable is statistically significant with a coefficient of -0.20 indicating that 80.0% (1-.20) of future efficiency savings is embedded in the model; the efficiency adjustment factor is 0.20.

Once the sales forecasts are developed, the system load shape forecast flows from the class sales forecasts. The process is to use customer class load shapes and fit the forecasted sales requirement by customer class to these class load shapes. Historic class load shapes were developed using BED's AMI data.

Emerging technologies such as photovoltaic ("PV") systems, EVs, cold climate heat pumps, and other technologies will likely have an impact on future demand for electricity. Over the past few years, there has been an increasing penetration of customers owning solar photovoltaic generating systems in Burlington.

Class Sales Forecasts

Changes in economic conditions, prices, weather conditions, as well as appliance saturation and efficiency trends drive energy deliveries and demand through a set of monthly customer class sales forecast models. Monthly regression models are estimated for each of the following major revenue classes.

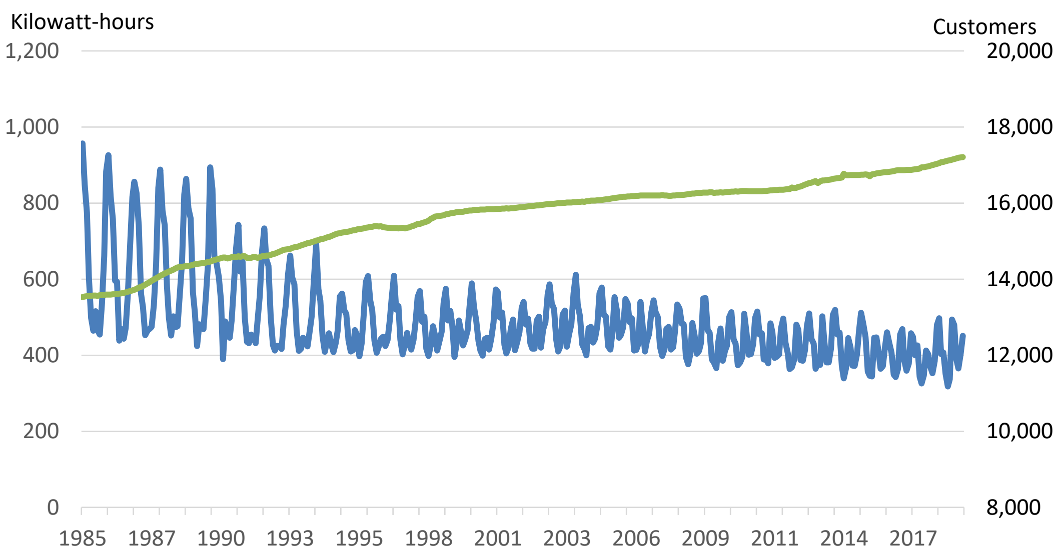
- Residential
- Commercial/Industrial
- Street Lighting

Residential Sector

The two main drivers of the residential forecast are the forecast of number of residential customers, and the forecast of use rate (electricity consumption per residential customer). The residential customers and use per customer are modeled separately and then the residential sales forecast is generated as the product of the customer forecast and the use per customer forecast.

Figure 9 shows the number of customers and the average monthly kWh use per customer for Burlington's residential sector for the period 1985 to 2018. Burlington has seen strong residential customer growth of 0.7% per year over the last 5 years, preceded by 15 years of growth rates averaging only 0.3% per year.

Figure 9: Residential Monthly Average kWh Use & Number of Customers



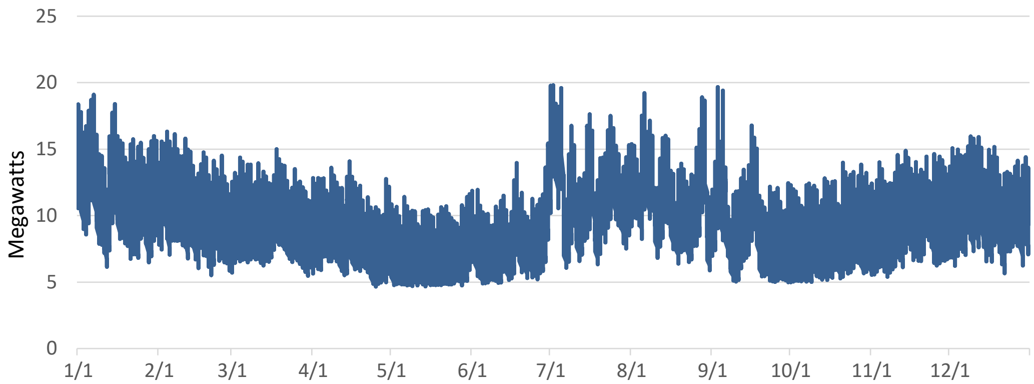
Declining use per customer reflects BED's history of energy efficiency, changing codes and standards, fuel switching, and end-use trends. Since 1985, residential use per customer has fallen more than 35%(from 7,533 kWh use per customer in 1985 to 4,889 kWh use per customer in 2018). The decrease has been particularly strong across the winter season, reflecting the impact of fuel switching and lighting efficiencies on usage.

By the end of 2018, there were 268 residential net-metering customers having a combined solar capacity of 1.1 MWs. The total solar PV generation in 2018 was 907,142 kWhs, lowering the average annual residential use per customer by 53 kWhs (1.1%).

Residential Load Shape

Residential electricity demand exhibits strong seasonal trends, with higher electricity use in the winter and summer months and minimum electricity use normally occurring during the spring and fall seasons. Demand levels during the winter and summer months tend to exhibit a significant daily variation in load, driven by extreme temperatures. The seasonal variability is demonstrated in Figure 10, which displays the residential hourly load profile for 2018.

Figure 10: 2018 Residential Hourly Net Demand



During 2018, the residential sector reached its highest (net) demand of 19,804 kWs during the hour ended 9:00 pm on July 2, 2018, which also happened to be the system peak day. The residential sector's maximum demand in the winter was not too far below the summer levels, reaching 19,102 kWs on January 7, 2018 at hour ended 7:00 pm.

Figure 11 and Figure 12 provide the residential sector "typical day" load profile plots for the summer and winter seasons. On average, residential loads tend to increase sharply during weekday mornings until around 8:00 am, followed by a levelling off or slight decline until 4:00 pm. After 4:00 pm, loads rise again peaking between 6:00 and 9:00 pm (depending on the season), and then taper off during the late evening hours. The weekend load profile is very similar to the weekday load profile, with the exception of the more gradual increase in the morning load. On winter and summer days where the temperature is extreme, the demand in all hours tends to be approximately 5 MWs higher than the average levels.

Figure 11: Residential Typical Day - Summer (Jun-Sep)

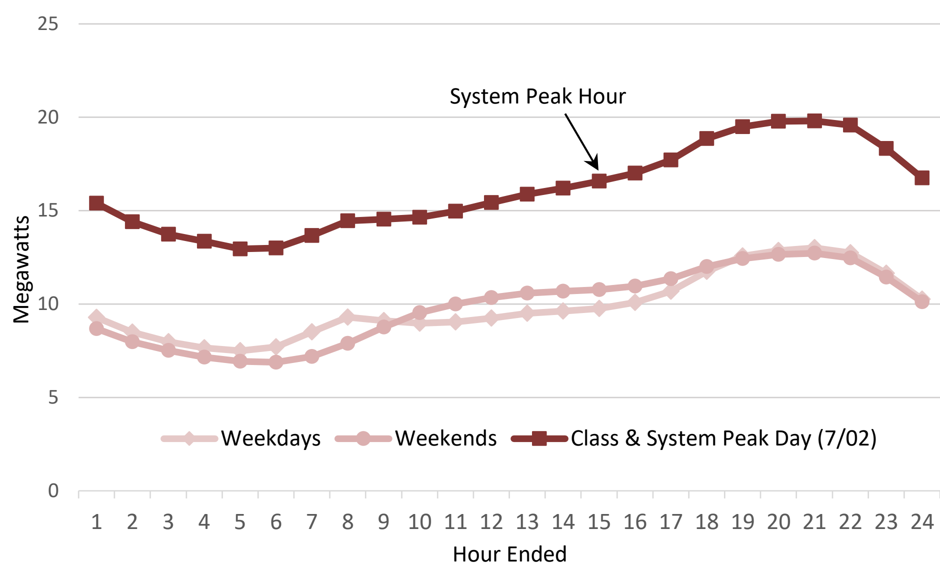
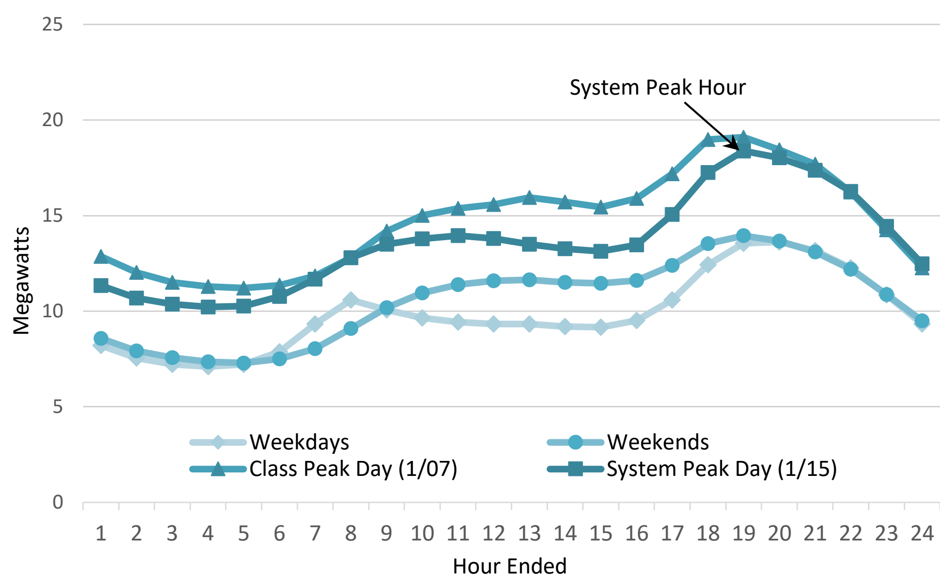


Figure 12: Residential Typical Day - Winter (Dec-Mar)



Residential Sales Forecast

The residential sales forecast is developed as a use-per-customer forecast multiplied by the forecasted number of customers. The residential use per customer is forecast using an SAE model. This model assumes that electricity use will fall into one of three categories: heating, cooling or other. The SAE model constructs variables to be used in an econometric equation where residential usage is a function of Xheat, Xcool and Xother variables.

The Xheat variable is derived by multiplying a heating index variable by a heating use variable. The heating index incorporates information about heating equipment saturation;

heating equipment efficiency standards and trends; and thermal integrity and size of homes. The heating use variable is derived from information related to days per month, heating degree-days, household size, personal income, and electricity prices.

The Xcool variable is derived by multiplying a cooling index variable by a cooling use variable. The cooling index incorporates information about cooling equipment saturation; cooling equipment efficiency standards and trends; and thermal integrity and size of homes. The cooling use variable is derived from information related to days per month, heating degree-days, household size, personal income, and electricity prices.

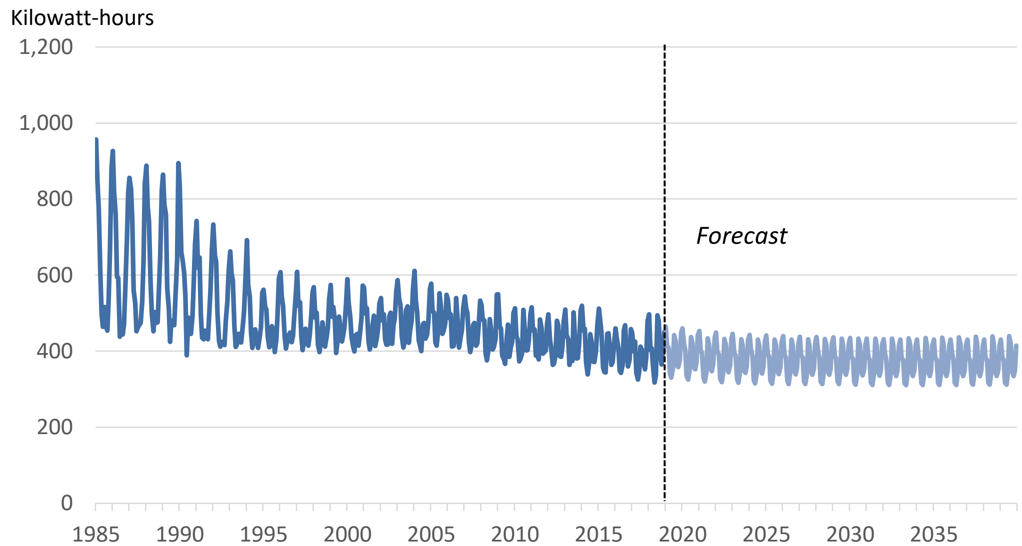
The Xother variable estimates the non-weather sensitive sales and is similar to the Xheat and Xcool variables. This variable incorporates information on appliance and equipment saturation levels, days per month, average household size, real personal income, and electricity prices.

The appliance saturations are based on historical trends from BED's residential customer surveys. The saturation forecasts are based on EIA forecasts and analysis by BED. The efficiency trends are based on DOE forecasts and Itron analysis. The thermal integrity and size of homes are for the Northeast Census Region and are based on DOE and Itron data and are calibrated to Burlington's mix of multi-family and single family housing units.

The economic and demographic assumptions that were used in the residential forecast models were supplied by Moody's Analytics, prepared in January 2019. The SAE model is estimated using over the period January 2010 to December 2018.

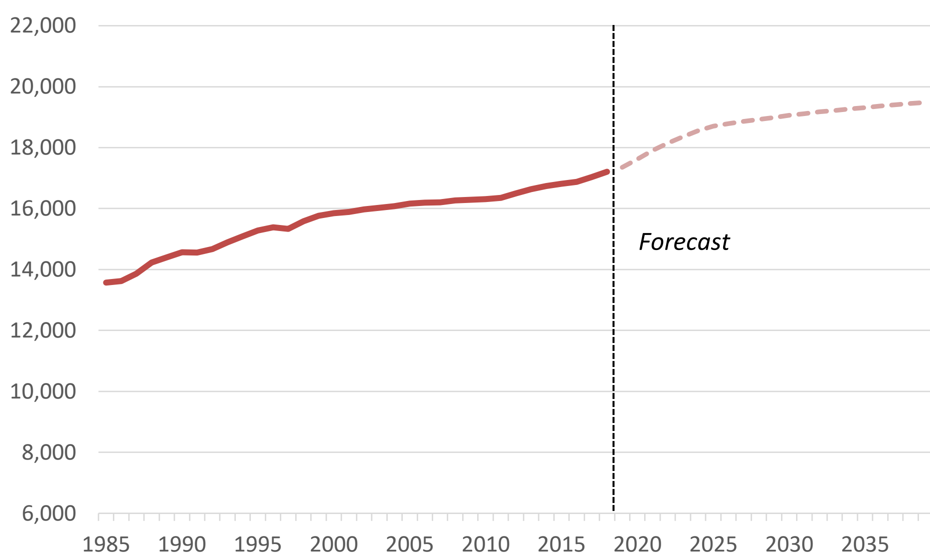
Figure 13 shows the residential average use forecast before making any adjustments for behind-the-meter generation and future EV adoption. Average use per customer is projected to decline further in the forecast period, albeit at a slightly slower rate. This is largely due to the continuing phase-out of the most common types of incandescent light bulbs mandated by the EISA and new end-use efficiency standards recently put in place by the DOE.

Figure 13: Monthly Residential kWh Use per Customer Forecast



The forecast of Burlington's residential customers is based on a monthly regression model using historical data from January 2010 to December 2018. The number of residential customers is forecasted using Burlington MSA housing unit projections as the major driver. Slightly stronger average customer growth rate in the period 2019-2025 is explained largely by the completion of a large residential project that is expected to add almost a thousand new customers over the next five years.

Figure 14: Residential Customer Forecast



Residential sales projections are then obtained by the combination of the customer projections and average use projections. With 0.3%decrease in average use and 0.6%increase in customer growth, residential sales average 0.3%growth between 2019 and 2039. Table 2 displays the annual residential sales forecast, excluding any impacts of behind-the-meter generation and EV adoption.

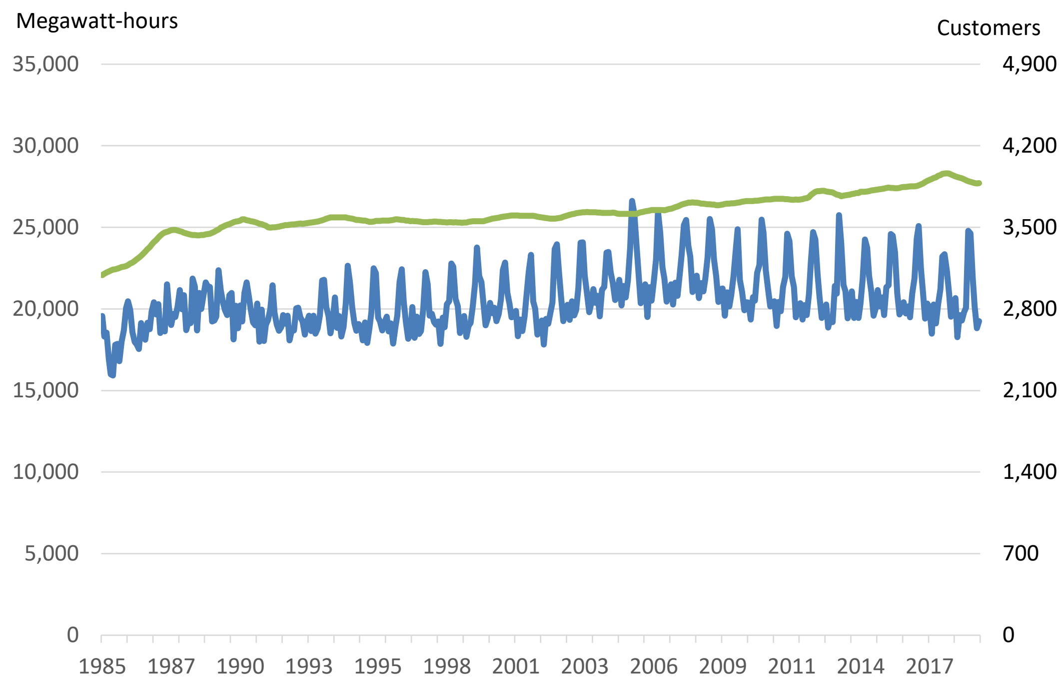
Table 2: Residential Sector Forecast (excluding PV and EV impacts)

Year	Total Sales (MWh)	% Chg.	Customers	% Chg.	Avg. Use (kWh)	% Chg.
2010	85,358	---	16,308	---	5,234	---
2011	84,876	-0.6%	16,350	0.3%	5,191	-0.8%
2012	83,671	-1.4%	16,502	0.9%	5,070	-2.3%
2013	85,481	2.2%	16,634	0.8%	5,139	1.4%
2014	83,628	-2.2%	16,741	0.6%	4,995	-2.8%
2015	83,479	-0.2%	16,810	0.4%	4,966	-0.7%
2016	82,422	-1.3%	16,876	0.9%	4,884	-1.6%
2017	80,590	-2.2%	17,032	0.9%	4,732	-3.1%
2018	85,334	5.9%	17,208	1.0%	4,959	4.8%
2019	82,057	-3.8%	17,353	0.8%	4,729	-4.6%
2020	82,452	0.5%	17,622	1.6%	4,679	-1.1%
2021	82,554	0.1%	17,902	1.6%	4,612	-1.4%
2022	83,128	0.7%	18,150	1.4%	4,580	-0.7%
2023	83,679	0.7%	18,354	1.1%	4,559	-0.5%
2024	84,512	1.0%	18,559	1.1%	4,554	-0.1%
2025	84,685	0.2%	18,702	0.8%	4,528	-0.6%
2026	84,859	0.2%	18,786	0.4%	4,517	-0.2%
2027	85,080	0.3%	18,860	0.4%	4,511	-0.1%
2028	85,555	0.6%	18,928	0.4%	4,520	0.2%
2029	85,613	0.1%	18,992	0.3%	4,508	-0.3%
2030	85,578	0.0%	19,058	0.3%	4,490	-0.4%
2031	85,632	0.1%	19,118	0.3%	4,479	-0.3%
2032	85,957	0.4%	19,173	0.3%	4,483	0.1%
2033	85,902	-0.1%	19,223	0.3%	4,469	-0.3%
2034	86,118	0.3%	19,268	0.2%	4,469	0.0%
2035	86,366	0.3%	19,315	0.2%	4,471	0.0%
2036	86,861	0.6%	19,363	0.2%	4,486	0.3%
2037	86,911	0.1%	19,407	0.2%	4,478	-0.2%
2038	87,152	0.3%	19,447	0.2%	4,482	0.1%
2039	87,346	0.2%	19,484	0.2%	4,483	0.0%
’10-‘18		0.0%		0.7%		-0.6%
’19-‘29		0.4%		0.9%		-0.5%
’19-‘39		0.3%		0.6%		-0.3%

Commercial Sector

BED’s commercial sector includes Small General Service, Large General Service, and Primary Service customer classifications. In 2018, this sector accounted for only 18%of total customers but 74%of the total kWh- sales. Figure 15 provides monthly MW sales and customer history for the commercial sector.

Figure 15: Commercial Monthly kWh Sales & Customers

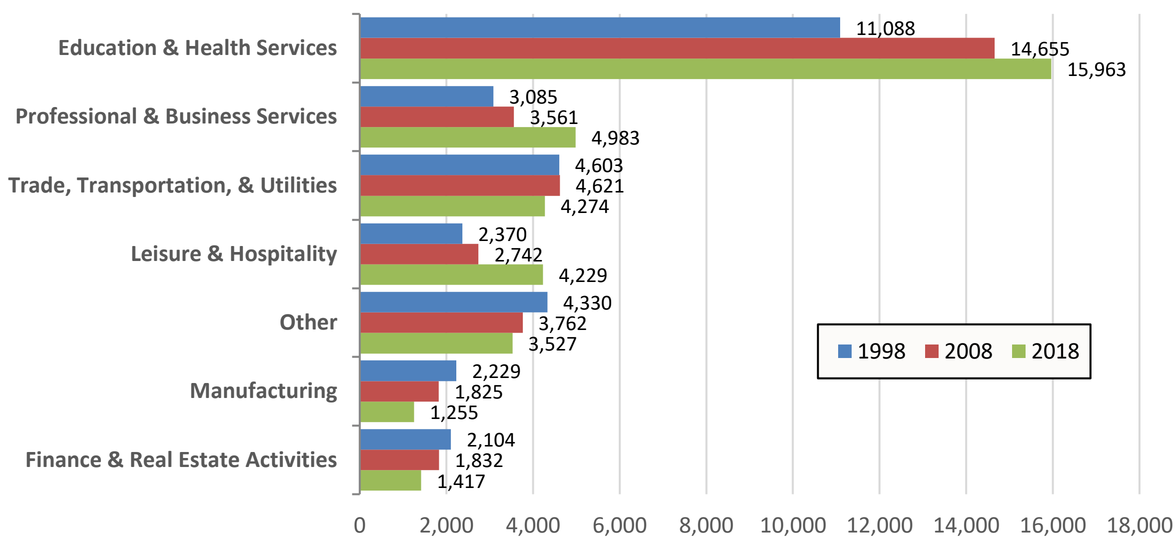


During the 20-year period prior to 1990, the commercial sector was experiencing 2.8%sales growth per year. Since then, commercial sector sales have remained relatively flat. This pattern can be attributed to changing economic conditions and energy efficiency programs and standards. Commercial sector load growth is linked to residential customer growth as demand for services, including healthcare, education, retail, food stores, and restaurants expand with population growth. However, as with the residential sector, changing codes and standards, and end-use trends have caused commercial sales to decline slightly in the last 10 years.

The major recessions have had a significant impact on employment in Burlington, particularly in the manufacturing sector. Manufacturing has traditionally been vital to Burlington because it creates well-paying jobs, draws investment into the area, and strengthens other sectors of the economy. Presently only 3.5%of Burlington's jobs are in the manufacturing sector – down from 15.3%in 1980. Two of BED's largest manufacturing customers left the City between 1990 and 2006, resulting in a significant loss of sales during that period.

Figure 16 provides a look at the employment trends by sector in Burlington over the last 20 years. The services sector, which includes education and health care services, represents one of the fastest growing employment categories in Burlington. UVM and the UVM Medical Center are the largest employers in the City, highlighting the importance of health and education services to both the growth and level of employment, as well as to electricity sales.

Figure 16: Burlington City Employment by Sector



There were 88 commercial net-metering (or group net-metering) BED customers by the end of 2018, having a combined solar capacity of 1.94 MW. The behind-the-meter solar impact on commercial sales in 2018 was 1,950,240 kWh (0.8%).

By the end of 2018, there were 88 commercial net-metering customers having a combined solar capacity of 1.9 megawatts. The total commercial solar PV generation in 2018was 1,950,240 kWs, offsetting commercial sales by 0.8%.

Commercial Load Shape

Figure 17 provides a plot of the aggregate hourly load for the commercial sector for 2018. We see increased loads during the summer months, which can be attributed to increased cooling requirements for these customers. The loads are quite consistent from day-to-day during the other times of the year, showing a consistent weekly pattern, with higher weekday loads and lower loads on weekends and holidays.

The commercial sector reached a maximum load of 50,619 KW on August 29, 2018, hour ending 3 pm, which was coincident with the second highest system peak of the summer. During the system peak hour, the load was 23%higher than the typical summer weekday load for this sector at this hour.

Figure 17: Commercial Sector: 2018 Hourly Load Profile

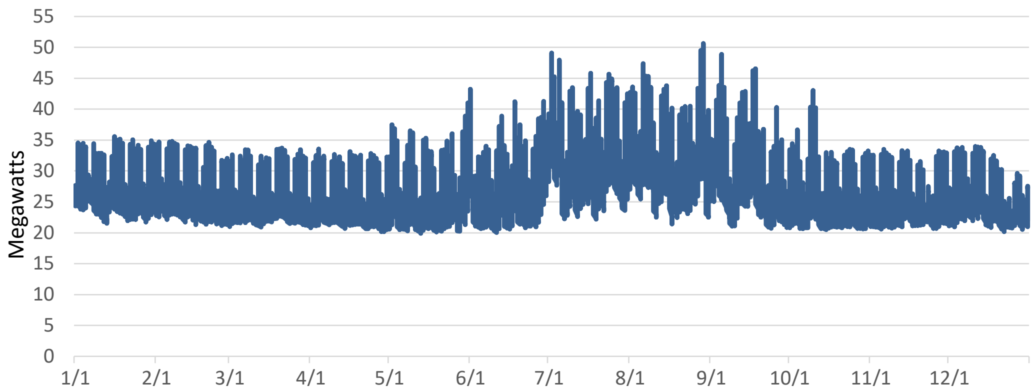


Figure 18 and Figure 19 provide the commercial sector "typical day" load profile for the summer and winter periods during 2018. During the weekdays, the commercial sector's load profile is characterized by one peak period, regardless of the season. During the day, loads increase sharply between 6:00 am and 12:00 pm, remain at high levels until about 4 pm, before gradually tapering off into the evening hours. During the summer months the commercial sector typically peaks around 2:00 or 3:00 pm during the weekdays, and slightly earlier in the winter months. Weekend loads are much lower in both the summer and winter months.

Figure 18: Commercial Typical Day - Summer (Jun-Sep)

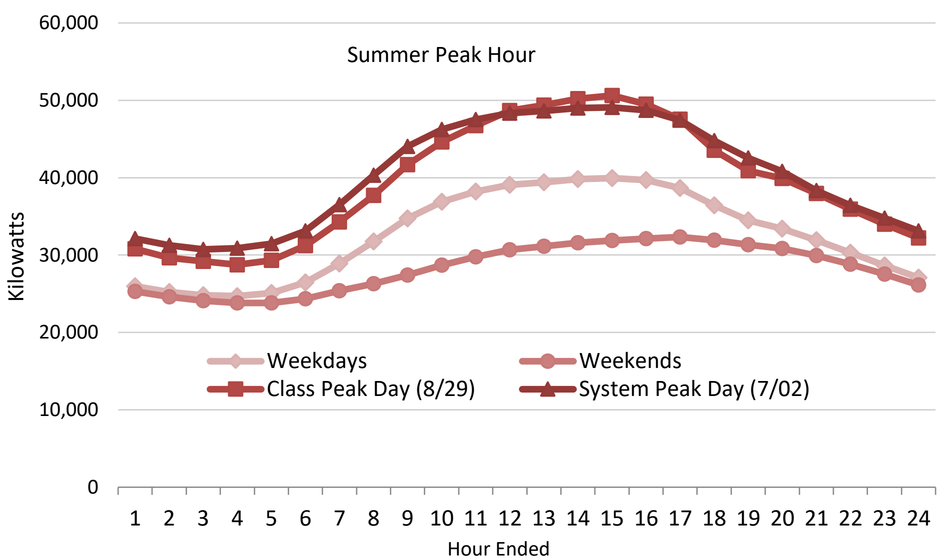
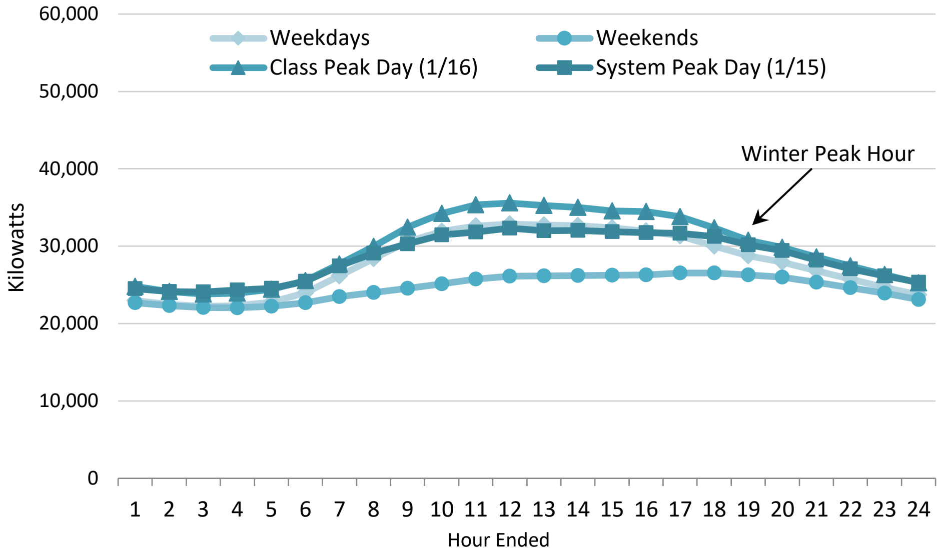


Figure 19: Commercial Typical Day - Winter (Dec-Mar)



Commercial Sales Forecast

Long-term commercial energy sales are forecasted using a SAE model. These models are similar to the residential SAE models, where commercial usage is a function of Xheat, Xcool and Xother variables.

As with the residential model, Xheat is determined by multiplying a heating index by a heat use variable. The variables incorporate information on heating degree-days; heating equipment saturation; heating equipment operating efficiencies; square footage; number of days in the month; commercial output and electricity price.

The Xcool variable uses measures similar to the Xheat variable, except it uses information on cooling degree-days and cooling equipment, rather than those items related to heating load. The Xother variable measures the non-weather sensitive commercial load. It uses non-weather sensitive equipment saturations and efficiencies, as well as billing days, commercial output and electricity price information.

The saturation, square footage and efficiencies are from the Itron base of DOE data and forecasts. The saturations and related items are from EIA's 2018 Annual Energy Outlook. The commercial output and employment data were provided by Moody's Analytics. The equipment stock and square footage information are for the Northeast Census Region, adjusted to Burlington.

The SAE is a linear regression for the period January 2010 through December 2018. As with the residential SAE model, the effects of EPAct, EISA, ARRA and EIEA2008, and other federal policies impacting end use efficiency are captured in this model.

BED's energy service engineers are in continual contact with the Burlington's large commercial customers about their needs for electric service. These customers relay information about load additions and reductions. This information is compared with the load forecast to determine if the commercial models are adequately reflecting these changes. If the changes are different from the model results, then add factors may be used to reflect those large changes that are different from those from the forecast models' output. Burlington recently lost sales due to a couple larger accounts (Burlington Town Center, and G.S. Blodgett). It is expected that sales will return as new customer enter these locations. In addition, there have been recent large additions at the University of Vermont, and others that are still expected (e.g., Tarrant Center), and these impacts will be applied as adjustment to the forecast.

Commercial sales are overall flat through the forecast period; improvements in end-use and building efficiency offset the impact of customer and economic growth. Table 3 shows the annual MWh sales forecast for the commercial sector, excluding any impacts from existing and future solar generation.

Table 3: Commercial Sector Forecast (excluding PV impacts)

Year	Total Sales (MWh)	% Chg.	Customers	% Chg.	Avg. Use (kWh)	% Chg.
2010	260,236	---	3,742	---	69,549	---
2011	255,266	-1.9%	3,737	-0.1%	68,302	-1.8%
2012	254,867	-0.2%	3,814	2.1%	66,833	-2.2%
2013	252,547	-0.9%	3,780	-0.9%	66,804	0.0%
2014	254,165	0.6%	3,821	1.1%	66,512	-0.4%
2015	258,489	1.7%	3,843	0.6%	67,268	1.1%
2016	256,346	-0.8%	3,898	1.4%	65,757	-2.2%
2017	250,821	-2.2%	3,945	1.2%	63,577	-3.3%
2018	249,734	-0.4%	3,878	-1.7%	64,392	1.3%
2019	249,064	-0.3%	3,893	0.4%	63,985	-0.6%
2020	251,154	0.8%	3,888	-0.1%	64,601	1.0%
2021	252,894	0.7%	3,880	-0.2%	65,173	0.9%
2022	255,635	1.1%	3,893	0.3%	65,667	0.8%
2023	255,422	-0.1%	3,905	0.3%	65,404	-0.4%
2024	255,834	0.2%	3,916	0.3%	65,336	-0.1%
2025	254,911	-0.4%	3,925	0.2%	64,942	-0.6%
2026	253,993	-0.4%	3,934	0.2%	64,556	-0.6%
2027	253,162	-0.3%	3,943	0.2%	64,206	-0.5%
2028	253,243	0.0%	3,951	0.2%	64,089	-0.2%
2029	252,183	-0.4%	3,960	0.2%	63,678	-0.6%
2030	250,716	-0.6%	3,969	0.2%	63,171	-0.8%
2031	249,432	-0.5%	3,977	0.2%	62,720	-0.7%
2032	248,998	-0.2%	3,984	0.2%	62,499	-0.4%
2033	247,389	-0.6%	3,991	0.2%	61,992	-0.8%
2034	246,504	-0.4%	3,997	0.2%	61,670	-0.5%
2035	245,687	-0.3%	4,004	0.2%	61,364	-0.5%

2036	245,556	-0.1%	4,011	0.2%	61,223	-0.2%
2037	244,343	-0.5%	4,018	0.2%	60,809	-0.7%
2038	243,790	-0.2%	4,026	0.2%	60,561	-0.4%
2039	243,879	-0.2%	4,033	0.2%	60,109	-0.4%
’10-‘18		-0.5%		0.5%		-0.9%
’19-‘29		0.1%		0.2%		-0.0%
’19-‘39		-0.1%		0.2%		-0.3%

Streetlighting

There are approximately 3,420 streetlights in the city of Burlington, and they accounted for less than 1%of total retail sales in 2018 (2,155 MWh). Since 2010, BED has increased efforts to replace streetlight fixtures with LED fixtures. By the end of 2018, more than 1,929 streetlights (56%) were converted to LED fixtures, resulting in a decline in street lighting sales of more than 29%during the period. Street lighting sales are fitted with a simple regression model driven by outdoor lighting energy intensity and seasonal variables. Between 2019 and 2039, street lighting sales are projected to decline by 2.1%per year.

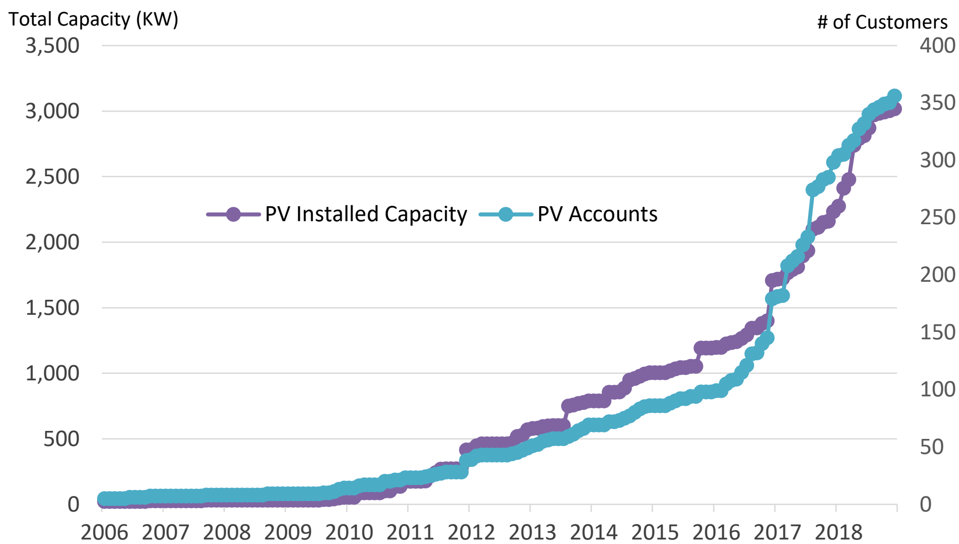
Adjustments for New Technologies

After class sales forecasts were developed, adjustments were made to account for the impacts of solar PV and EV adoption. The following section describes an overview of these adjustments, with further details provide in the Itron report in Appendix A.

Solar Forecast

The BED energy and peak forecast incorporates the impact of expected behind the meter PV adoption. Although relatively small in magnitude compared to the rest of Vermont, BED has experienced an uptick growth in the number and size of PV systems over the past two years. Part of the jump was due to customers racing to beat changes in net metering laws that reduced system incentives. While some of the recent adoption is incentive-driven, continuing system cost declines will drive future long-term adoption. Figure 20 shows the recent trends in PV adoption. By the end of 2018, BED had 356 net-metering customers, with a total solar capacity of 3.0 MWs and an annual reduction in sales of 2,857 MWs (0.8%of total BED sales).

Figure 20: Solar PV Adoption in City of Burlington



The PV adoption models (residential and commercial) relate the share of customers that have adopted solar systems to simple payback through a cubic model specification. The payback calculation is based on total installed cost, annual savings from reduced energy bills and incentive payments for total generation. With declining system costs and incentives, we are expecting to see solar adoption increase to 1,088 residential customers (5.6%penetration) and 177 commercial customers (4.4%penetration).

The installed solar capacity is the product of the solar customer forecast and the assumed average system size, for both the residential and commercial classes. The average assumed sized is 4.0 kWs for residential systems and 22 kWs for commercial systems, which is the average system size for all systems installed through 2018. The capacity forecast is then translated into a monthly generation forecast by applying monthly solar load factors to the capacity forecast. The monthly load factors are derived from a typical PV load profile for Burlington VT. The forecasted PV shape is from the National Renewable Energy Laboratory ("NREL") and represents a typical meteorological year ("TMY").

Table 4 shows the PV capacity forecast and expected annual generation impacts. By 2039, the solar capacity is expected to reach 8.3 MWs, providing approximately 10,491 MWhs of generation per year. The number of PV customers represents the number of customers who either install solar locally, and those who are part of a community solar array.

Table 4: Solar PV Forecast

	2019	2024	2029	2034	2039
Residential PV Customers	295	711	811	977	1,088
% of Total Residential Customers	1.7%	3.8%	4.3%	5.1%	5.6%
Commercial PV Customers	91	134	144	155	177
% of Total Commercial Customers	2.3%	3.4%	3.7%	3.9%	4.4%
Installed Capacity (MW)	3.2	5.8	6.5	7.4	8.3
Generation MWhs	3,947	7,255	8,013	9,132	10,279

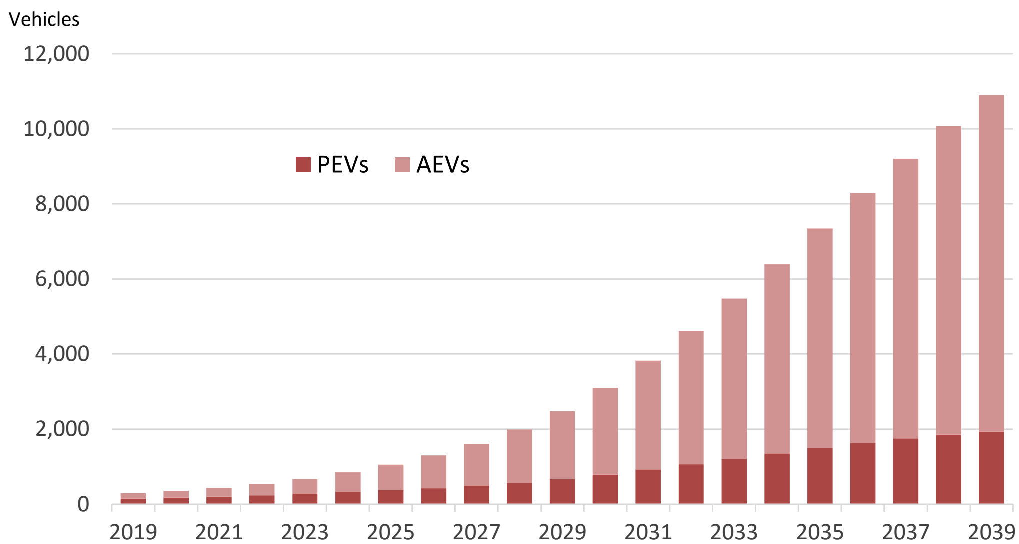
Electric Vehicle Forecast

For the first time, BED has integrated its forecast models with explicit individual forecasts of EV adoptions. At the time of the forecast there were 222 registered all EVs ("AEVs") and plug-in hybrid EVs ("PEVs") in Burlington. With 25,335 total registered light-duty vehicles, AEV/PEVs account for less than 1%of all vehicles on the road. While AEV/PEVs currently represent a small percentage of vehicles, improvements in charging infrastructure and continued state and federal incentives will ensure their increased adoption rate.

To quantify the impacts of EVs on the system over the 20-year period, BED reviewed EV forecasts from numerous sources and chose an EV adoption forecast based on a recent Bloomberg New Energy Finance forecast of AEV/PEV sales as a percentage of total new vehicle sales. Currently, AEV/PEV sales account for 2-3%of new vehicle sales nationally, this is forecasted to increase to nearly 60%by 2039. The forecast also accounts for the changing mix of AEV and PEV sales(currently the mix is approximately 50/50), but AEV sales are forecasted to increase to more than 80%of all AEV/PEV sales by 2039.

For the service area, the EV forecast involves a significant increase in the number of vehicles through 2039. Figure 21 shows the cumulative number of EVs, which is projected to increase from 222 to nearly 11,000 by 2039. The EVs will contribute more than 25,000 MWhs in energy demand growth in Burlington by 2039.

Figure 21: Projected Number of EVs



EVs' impact on the BED system profile will depend on when owners choose to charge their vehicles. Off-peak charging can be promoted by providing time of use ("TOU") incentive electric rates for vehicle owners. The forecast assumes two different charging profiles; a traditional profile in which vehicles begin to charge as drivers return to their homes, and an incentive profile in which charging is delayed to later in the evening with the use of a TOU incentive rate. BED assumes that 80% of the AEV energy will be charged based on the incentive profile and 20% on the traditional charge profile.

Table 5: EV Forecast

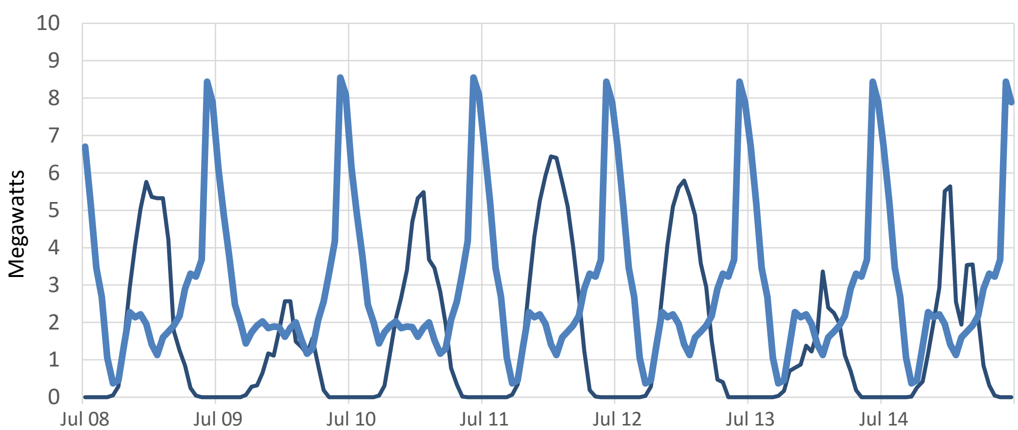
	2019	2024	2029	2034	2039
Total Number of Vehicles	25,552	27,327	27,965	28,371	28,688
Number of AEVs	145	519	1,809	5,035	8,967
% AEV	0.6%	1.9%	6.5%	17.7%	31.3%
Number of PEVs	149	325	666	1,356	1,935
% PEV	0.6%	1.2%	2.4%	4.8%	6.7%
AEV/PEV MWhs	569	1,758	5,496	14,629	25,411

System Load Shape Forecast

After developing the forecasts of monthly energy sales by customer class, a forecast of hourly system loads is developed in three steps. First, a monthly peak forecast is developed. The monthly peak model uses historical peak-producing weather and incorporates the impact of weather on peak loads through several weather variables that drive heating and cooling usage. The weather variables include the average temperature on the peak day. The peak forecast is based on average monthly historical peak-producing weather. Next, class hourly load forecasts are derived by combining class load profiles with class sales forecasts. Class hourly profiles are expressed as a function of daily Heating Degree Days ("HDD") and Cooling Degree Days ("CDD"), binary for day of the week, month, seasons and holidays, and hours of light. Class sales forecasts are then combined with these hourly profile forecasts and adjusted for line losses to create a baseline load profile.

The baseline load profile forecast is then adjusted for solar PV and EV adoption. PV reduces system load and demand while EVs add to the baseline system load. Figure 22 shows projected PV and EV loads for the July peak week in 2039.

Figure 22: Solar & EV Load Impacts in July 2039



By 2039, EVs add 8.4 MW of load at 11:00 pm and behind-the-meter solar reduces load by 5.8 MW at 1:00 pm. The adjusted system load and projected peaks are derived by adding the PV and EV hourly forecasts. The combined impact of these adjustments moves the net system peak to hour 7:00 pm.

Over the next twenty years, base case system energy requirements average 0.3%annual growth with customer growth of 0.5%. Peak demand increases 0.2%annually over this period. In comparison, since 2010, system energy has declined on average 0.5%annually and peak demand has declined 0.1%on average. Positive forecasted energy requirements are largely the result of expected EV sales growth in the second half of the forecast period.

Table 6 shows the BED energy and demand forecast, after accounting for the effects of future energy efficiency and net-metering.

Table 6: Energy & Peak Forecast

Year	Energy (MWh)	% Chg.	Summer Peak (MW)	% Chg.	Winter Peak (MW)	% Chg.
2010	358,868	---	70.4	---	52.2	---
2011	353,211	-1.6%	65.8	-6.5%	53.5	2.5%
2012	350,753	-0.7%	63.6	-3.3%	50.9	-4.9%
2013	349,150	-0.5%	67.2	5.7%	53.1	4.3%
2014	348,338	-0.2%	64.1	-4.6%	53.5	0.8%
2015	350,950	0.7%	64.7	0.9%	53.0	-0.9%
2016	347,309	-1.0%	65.2	0.8%	50.5	-4.7%
2017	338,936	-2.4%	61.7	-5.4%	49.7	-1.6%
2018	341,234	0.7%	67.3	9.1%	50.3	1.2%
2019	336,402	-1.4%	64.5	-4.1%	51.0	1.4%
2020	338,299	0.6%	64.8	0.4%	50.9	-0.3%
2021	339,933	0.5%	65.2	0.6%	51.7	1.6%
2022	342,348	0.7%	65.4	0.3%	51.7	0.0%
2023	342,126	-0.1%	65.2	-0.2%	51.9	0.3%
2024	343,500	0.4%	65.4	0.3%	52.0	0.2%
2025	343,029	-0.1%	65.4	-0.1%	51.8	-0.3%
2026	342,657	-0.1%	65.3	0.0%	51.8	0.1%
2027	342,650	0.0%	66.3	1.1%	51.9	0.1%
2028	343,789	0.3%	65.5	-1.3%	51.9	0.0%
2029	343,693	0.0%	65.4	-0.1%	51.7	-0.4%
2030	343,418	-0.1%	65.3	-0.2%	51.6	0.0%
2031	343,637	0.1%	65.2	-0.1%	51.6	0.0%
2032	345,036	0.4%	65.3	0.1%	51.9	0.4%
2033	345,130	0.0%	65.2	-0.1%	51.8	-0.1%
2034	346,245	0.3%	65.3	0.0%	51.8	0.0%
2035	347,589	0.4%	65.3	0.1%	51.9	0.0%
2036	349,961	0.7%	65.5	0.3%	52.2	0.7%
2037	350,755	0.2%	65.6	0.2%	52.6	0.7%
2038	352,314	0.4%	65.8	0.4%	52.8	0.4%
2039	353,667	0.4%	66.0	0.3%	52.7	-0.1%
'10-'18		-0.6%		-0.4%		-0.4%
'19-'29		0.2%		0.1%		0.1%
'19-'39		0.3%		0.1%		0.2%

Alternative Forecast Scenarios

BED uses scenarios that represent possible futures that could unfold over the next 20 years. The role of the scenario is not to predict the future, but to offer us the opportunity to use an imagined future as a dress rehearsal. In this IRP, BED defined two electrification scenarios – each is to achieve net zero emission targets by specific target years – 2030 and 2040; the 2030 scenario is the more aggressive scenario.

Synapse Energy Economics was contracted to develop a net zero energy roadmap for the City of Burlington, and provided electrification impacts relative to our business as usual scenario. Table 7 and Table 8 provide estimates of the additional MWh impacts expected under the two electrification scenarios.

Table 7: Impact of Net Zero 2040 Scenario Relative to the BAU Scenario

Impact		2019	2024	2029	2034	2039
Res Electric Space Heating	*MWh*	1,313	20,186	38,009	42,099	45,350
Res Electric Water Heating	*MWh*	566	9,037	19,851	22,746	22,059
Res Electric Space Cooling	*MWh*	200	2,138	4,092	5,093	5,718
Res Efficiency	*MWh*	(234)	(789)	(853)	(884)	(919)
Electric AEV Vehicles	*MWh*	8	3,895	13,098	17,610	17,480
Electric PEV Vehicles	*MWh*	10	2,465	7,390	9,549	9,069
Res Behind the Meter Solar	*MWh*	(93)	(581)	(878)	(1,385)	(1,619)
Com Electric Space Heating	*MWh*	1,499	17,657	26,706	31,016	31,452
Com Electric Water Heating	*MWh*	177	1,767	3,622	5,108	6,013
Com Electric Cooking	*MWh*	590	9,165	21,398	33,593	37,807
Com Efficiency	*MWh*	(699)	(3,879)	(6,090)	(7,803)	(9,431)
Com Behind the Meter Solar	*MWh*	(82)	(805)	(1,289)	(1,552)	(1,921)
Total	***MWh***	**3,255**	**60,256**	**125,056**	**155,190**	**161,058**

Table 8: Impact of Net Zero 2030 Scenario Relative to the BAU Scenario

Impact		2019	2024	2029	2034	2039
Res Electric Space Heating	*MWh*	3,662	47,218	60,695	57,027	51,605
Res Electric Water Heating	*MWh*	689	11,233	21,867	22,743	21,871
Res Electric Space Cooling	*MWh*	433	3,939	5,500	5,883	5,973
Res Efficiency	*MWh*	(234)	(789)	(853)	(884)	(919)
Electric AEV Vehicles	*MWh*	53	6,570	26,345	33,318	28,400
Electric PEV Vehicles	*MWh*	49	3,906	9,699	9,336	5,772
Res Behind the Meter Solar	*MWh*	(93)	(581)	(878)	(1,385)	(1,619)
Com Electric Space Heating	*MWh*	1,801	36,070	46,421	47,930	41,164
Com Electric Water Heating	*MWh*	174	1,861	3,810	5,896	5,878
Com Electric Cooking	*MWh*	590	9,165	21,398	33,593	37,807
Com Efficiency	*MWh*	(699)	(3,879)	(6,090)	(7,803)	(9,431)
Com Behind the Meter Solar	*MWh*	(82)	(805)	(1,289)	(1,552)	(1,921)
Total	***MWh***	**6,343**	**113,908**	**186,625**	**204,102**	**184,580**

With a strong increase in cold climate heat pump adoption, peak demand shifts from the summer months to winter months. By 2030, the aggressive electrification scenario results in a peak demand that is more than double the business as usual peak demand forecast. Figure 23 and Figure 24 compare the hourly load shapes for the years 2030 and 2039 for each of the scenarios.

Figure 23: Scenario Load Comparison in 2030

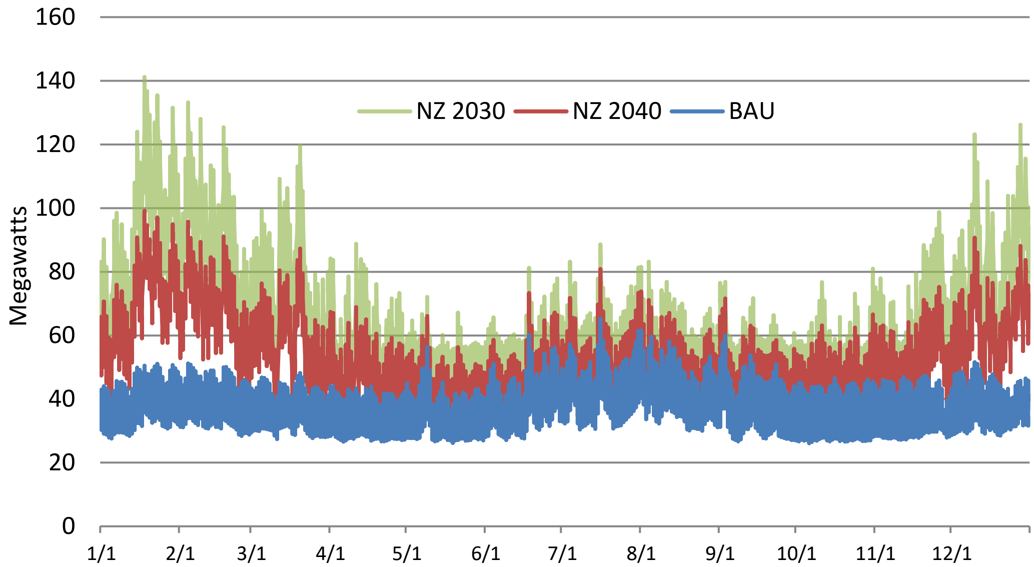


Figure 24: Scenario Load Comparison in 2039

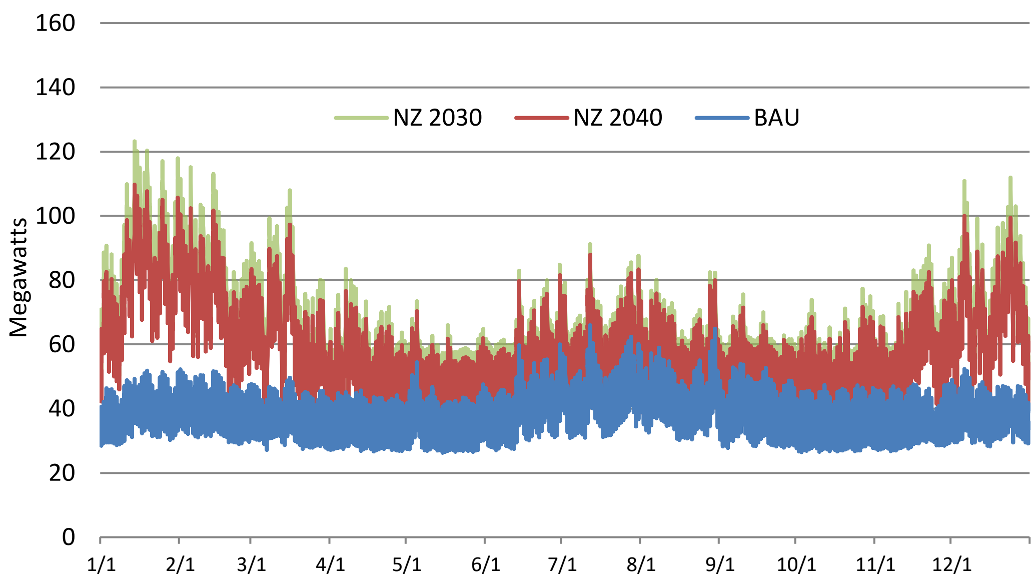


Figure 25 and Figure 26 provide a look at the peak day load shape in 2030 and 2039 for the Net Zero 2030 scenario. The load shape is characterized by dual peak periods occurring in the morning around 8:00 or 9:00 am, and in the evening at 11:00 pm.

Figure 25: 2030 Peak Day (1/18) assuming the NZ2030 Scenario

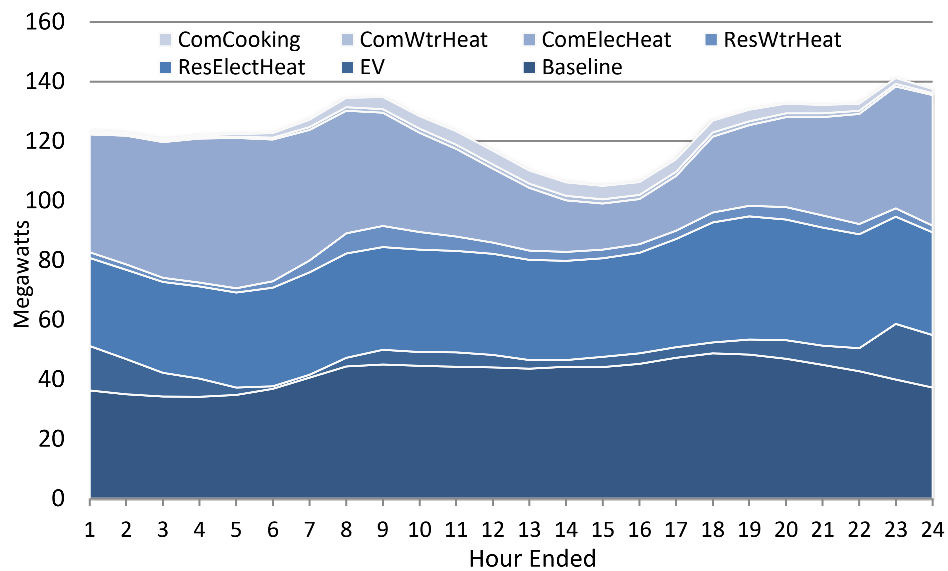
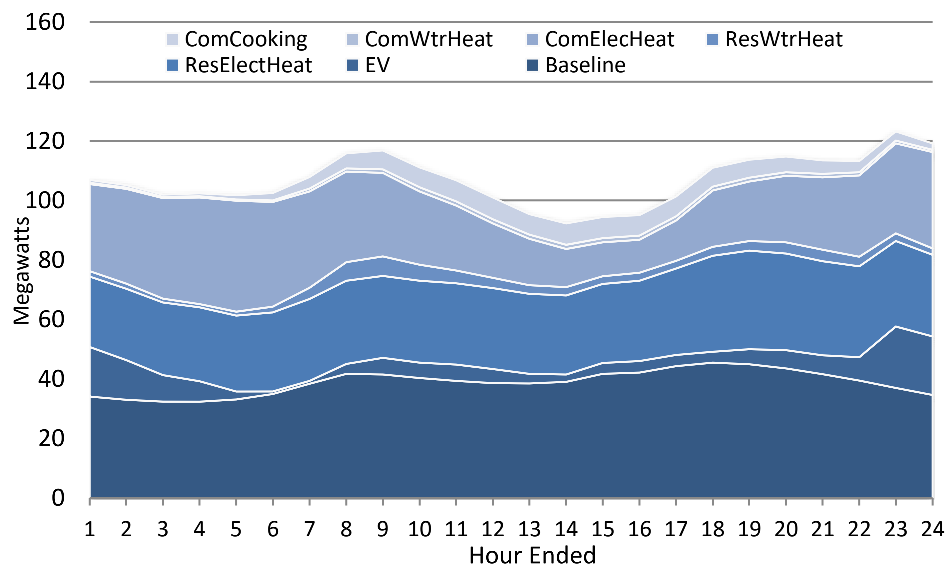


Figure 26: 2039 Peak Day (1/14) assuming the NZ2030 Scenario



Weather was not included as a sensitivity case for the system energy forecast because weather patterns tend to be sporadic and lean toward an average over the long term. The business as usual peak scenario was also evaluated using extreme peak day temperature (a one in ten chance of occurring). This resulted in peak loads that were about 3.7%higher than peaks under average peak weather conditions. Table 9 provides a final summary of the peak and energy forecasts for the various scenarios.

Table 9: System Peak & Energy Forecast Scenarios

	System Energy (MWH)			System Peak (MW)			
Year	BAU	NZE 2040	NZE 2030	BAU 50/50	BAU 90/10	NZE 2040	NZE 2030
2019	336,402	339,784	342,871	64.5	67.2	64.9	65.4
2020	338,299	347,394	365,940	64.8	67.5	65.7	67.3
2021	339,933	359,635	390,726	65.2	67.9	66.9	74.6
2022	342,348	376,142	417,098	65.4	68.1	68.4	85.7
2023	342,126	388,429	436,852	65.2	68.0	70.2	95.9
2024	343,500	403,762	457,413	65.4	68.2	75.1	102.8
2025	343,029	418,187	474,330	65.4	68.2	79.8	109.4
2026	342,657	431,557	488,349	65.3	68.1	84.3	114.2
2027	342,649	444,481	500,181	66.3	69.2	88.9	118.1
2028	343,789	457,867	511,237	65.5	68.3	91.5	120.3
2029	343,693	467,801	529,370	65.4	68.3	96.2	126.5
2030	343,418	475,770	559,027	65.3	68.2	99.1	141.2
2031	343,637	483,133	556,901	65.2	68.1	101.6	139.2
2032	345,036	490,715	554,908	65.3	68.2	102.4	135.5
2033	345,130	495,738	551,198	65.2	68.1	103.4	133.1
2034	346,245	499,275	548,188	65.2	68.1	106.4	132.9
2035	347,589	501,376	544,274	65.3	68.2	106.4	129.8
2036	349,961	503,328	540,124	65.5	68.4	106.0	126.1
2037	350,755	505,876	538,026	65.6	68.5	106.9	124.7
2038	352,314	509,573	537,093	65.8	68.6	109.0	124.4
2039	353,667	511,314	534,837	66.0	68.7	109.8	123.2
20-Year CAGR:	0.25%	2.06%	2.25%	0.11%	0.11%	2.66%	3.22%

Figure 27 and Figure 28 compare energy and demand net zero scenario forecasts against the business as usual case.

Figure 27: System Energy Forecast Scenarios

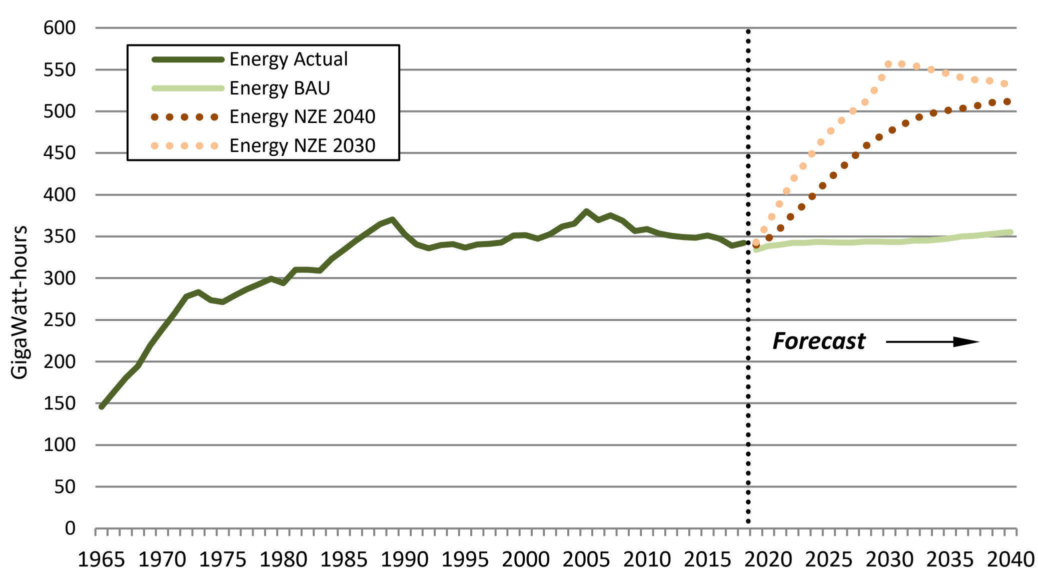


Figure 28: System Peak Demand Scenarios