City of Burlington Electric Department
2023 Integrated Resource Plan

Prepared for the Vermont Public Utility Commission
November 1, 2023

Photo courtesy of Hula Lakeside, a geothermally heated and cooled building
Lakeside Ave., Burlington, Vermont

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Executive Summary

Pursuant to 30 V.S.A. § 218c, the City of Burlington, Vermont Electric Department ("BED") submits its 2023 Integrated Resource Plan ("IRP") for review and approval. In the sections that follow, BED describes its decision-making framework to meet its customers' "need for energy services, after safety concerns are addressed, at the lowest present value life-cycle costs, including environmental and economic costs through a strategy of combining investments and expenditures on energy supply, transmission and distribution capacity and distribution efficiency and comprehensive energy efficiency programs."[1] Economic costs identified in this IRP have been fully analyzed with due regard to:

"the greenhouse gas inventory developed under the provisions of 10 V.S.A. § 582;
the State's progress in meeting its greenhouse gas reduction goals;
the value of the financial risks associated with greenhouse gas emissions from various power sources; and
consistency with section 8001 (renewable energy goals) of this title."[2]

As further summarized in Chapter 4, BED's comprehensive energy efficiency programs include a set of coordinated investments and program expenditures designed to "meet the public's need for energy services through efficiency, conservation, or load management across all of our customer classes."[3] Investments in efficiency include all known direct and indirect costs incurred to implement such efficiency programs, as well as all known direct and indirect customer and societal benefits, such as environmental impacts and health effects. This plan also discusses issues related to environmental justice and energy equity, as well as the distribution of potential environmental benefits that may result from the decisions BED chooses to make in the future.[4]

Objectives

The primary objective for this IRP is to describe the processes, procedures, and tools that BED relies on to make investment decisions, manage risks, and ensure the delivery of safe, reliable, cost-effective energy services in a manner that is consistent with Vermont's energy policies and plans.[5] Consistent with BED's [strategic direction](), this IRP also demonstrates how BED will continue to:

- Engage with its customers and the community;

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[1] 30 V.S.A. §218c.
[2] 30 V.S.A. §218c.
[3] See Case 22 – 2954, Order of 9/26/2023.
[4] Act 154 (2022).
[5] 30 V.S.A. §202(f).

- Strengthen the reliability and safety of our electric energy delivery systems;
- invest in our people, processes, and technology;
- innovate to reach net zero energy, and;
- manage our budget and operational risks responsibly.

This IRP satisfies the requirements of Vermont's energy policies and plans for the following reasons:

- It identifies key input variables and risks that could impact operations;
- It describes how BED will manage those identified risks;
- It documents how BED can reliably meet the energy needs of its customers, after safety concerns are addressed, at the lowest present value lifecycle costs; and
- It highlights a series of priority action steps to be taken in the future.

In presenting this IRP to the Public Utility Commission ("Commission") for review, we are mindful of the ever-changing nature of the electric utility industry. Policies and planning procedures continue to evolve as technology advances. The range of investment options to balance supply and demand are expanding at an increasing rate as new generation, load control, energy storage, and other communications technologies become available and affordable. As distributed energy resources are deployed in ever-greater numbers throughout Vermont, BED (and other distribution utilities) must plan for and build a more advanced energy delivery system, a system that is no longer monolithic and centralized but is instead distributed, resilient, flexible, and dynamic.

The IRP process provided BED the opportunity to consider the range of implications of its energy delivery systems and plan for its construction based on the decision-making framework, analytical methodologies, and tools described herein. Our intent is to build a system or systems that can be optimized to the greatest extent possible across spatial and temporal dimensions, and, most importantly, a system that supports our mission to "serve the energy needs of our customers in a safe, reliable, affordable, sustainable, and socially responsible manner."

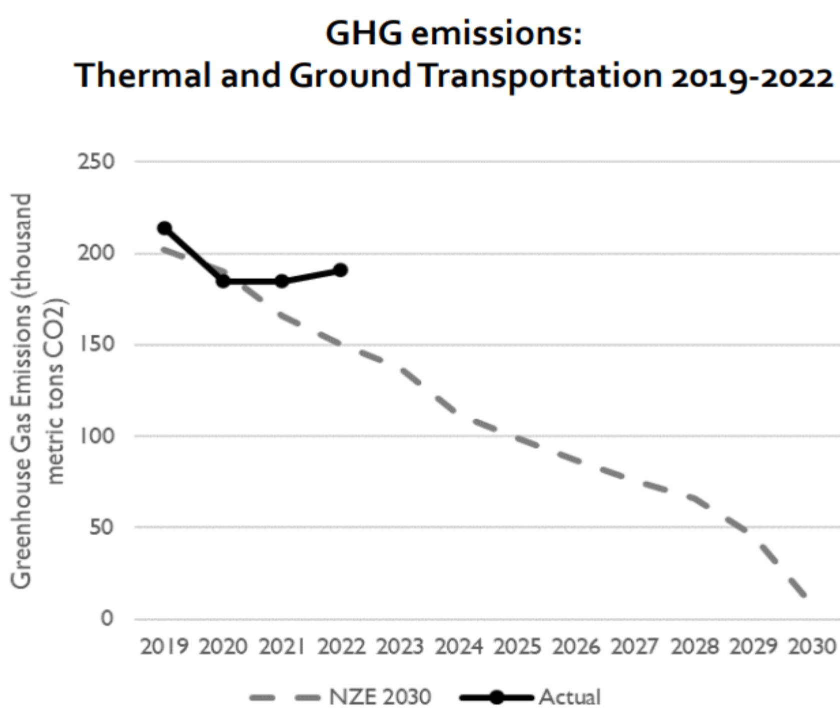
Net Zero Energy Roadmap Update

The City of Burlington adopted BED's Net Zero Energy Roadmap ("NZE Roadmap") in September 2019. The NZE Roadmap highlighted four comprehensive pathways for eliminating fossil fuels in the building and ground transportation sectors by 2030 or 2040. Those pathways focused on:

- Efficient electric buildings,
- Electric vehicles,
- District Energy, and;
- Alternative transportation.

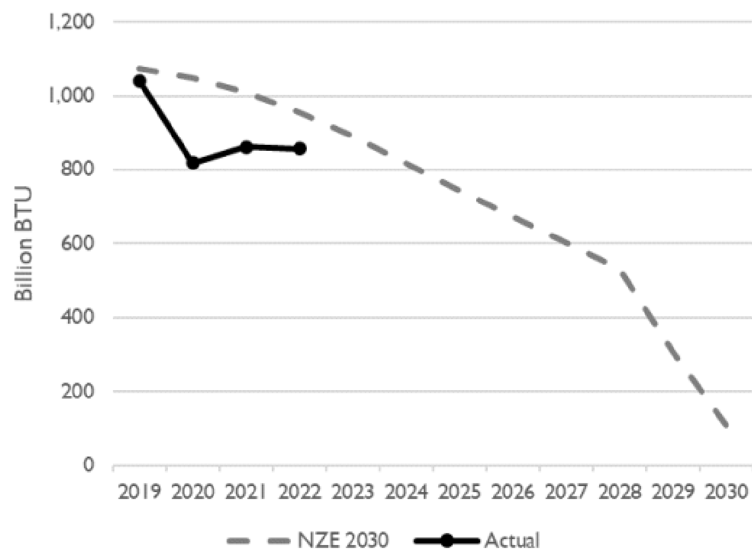
In 2022, BED updated the key metrics associated with progress toward the NZE Roadmap. That update found that while progress in fossil fuel reductions have been significant, more work is necessary to fully achieve net zero energy ("NZE") by 2040. Burlington's emissions, while down 11.2% in 2022 relative to 2018, have rebounded relative to pandemic-impacted 2020, as shown in Figure 0-1 below. Much of the increase is attributable to increased commercial natural gas consumption as businesses re-opened, as well as warmer than usual weather patterns (GHG emissions were not weather-normalized), and completion of several new commercial construction projects.

Figure 0-1: Burlington thermal and ground transportation greenhouse gas emissions



Reductions in gas and diesel consumption, however, are ahead of original projections. As shown in Figure 0-2, transportation-related fuel consumption in 2022 was 10.6% lower than the 2019 NZE Roadmap forecast due primarily to increased electric vehicle ("EV") adoption and lower vehicle miles travelled coming out of the 2020 pandemic.

Figure 0-2: Burlington gasoline and diesel fuel consumption



While the challenges to achieving NZE are substantial, BED is steadfast in its commitment to encouraging customers to eliminate fossil fuel use across the electric, thermal, and ground transportation sectors by strategically electrifying, managing demand, realizing efficiency gains, and expanding local renewable generation while increasing system resilience.

For purposes of this IRP, however, BED assumes that the current pace of future customer adoption of beneficial electrification, weatherization, and other clean energy initiatives will not occur on the timeline described in the NZE Roadmap. Rather, the findings and recommendations of this IRP reflect a base case scenario for load growth. The base case scenario assumes current adoption rates of beneficial electrification technologies (e.g., EVs and heat pumps) continue along a similar trajectory as in the recent past (i.e., 2022 and 2023) for the next several years, which is relatively modest compared to 2020 (which was an exceptional Tier III performance year). Flat to modest load growth means that with planned investments in generation resources, purchased power arrangements and infrastructure upgrades will also be flat to modest relative to a NZE scenario. The base case scenario anticipates that peak demand for energy is likely to remain well below the 140 MW winter peak scenario projected in the NZE Roadmap. A base case scenario of 69.9MW remains critically important for planning purposes, however, as it is the most likely scenario for which BED needs to plan to satisfy its resource adequacy requirements under 30 V.S.A. §218c. The results of our base case scenario also serve as a point of comparison to higher levels of beneficial electrification adoption even if current adoption levels are less than the rate necessary to achieve NZE by 2042.

Thus, this IRP includes high case and low case scenarios for load growth. Under the high case scenario, we assume that the City of Burlington nearly reaches its NZE goals by 2042 in the transportation and residential heating sectors. The high case scenario assumes stable-to-improving economic conditions (i.e., stable employment levels, increasing levels of new construction/housing starts, and favorable interest rates), continued federal and state financial support and, finally, a growing acknowledgement by all customers of the connection between human-generated carbon emissions and severe climate disruptions. The low case scenario assumes current trends falter slightly due to any number of reasons, such as higher than expected inflation and/or lower employment levels.

While BED remains committed to help the City achieve the NZE Roadmap goals, we also acknowledge that progress will require a significant shift in how the community thinks about and consumes energy in the thermal and ground transportation sectors. Making the transition to an NZE city will require policy changes, enhanced incentives, and significant investment in new technology. Several key factors that could accelerate this transition are beyond BED's control, including the pace of change for electric transportation and heating technologies, federal policies such as fuel economy standards and tax incentives, federally funded grants, state policy initiatives including whether Vermont or the region prices carbon, and the potential for non-linear adoption rates for technology as prices come down.

One significant, positive development is the federal government's Inflation Reduction Act of 2022 ("IRA"). Under the IRA, federal income tax credits and other benefits are being made available to foster the development and deployment of clean energy technologies to dramatically reduce greenhouse gas emissions in line with the Paris Agreement of 2015. The IRA represents an inter-generational investment of enormous magnitude. Federal funding in the form of tax credits and grants is expected to bring climate-friendly technology costs down 40% over the next dozen years. As costs decline, the steeper the rate of beneficial electrification adoption. BED expects that the effects of the IRA, as well as other Vermont-specific policies such as the Clean Cars initiative, will be profound but take time to reveal themselves in the data. In the meantime, BED shares responsibility with other Vermont stakeholders and distribution utilities to continue funding effective programs, such as Tier III, energy efficiency, and dynamic distributed energy resources, to maintain Vermont's momentum toward a cleaner energy system and economy.

With the filing of this IRP, BED also acknowledges its responsibility to identify and effectively address social and racial justice issues in our community. It is imperative that our energy programs and services continue to be available, accessible, and affordable to all our customers. In coordination with our City partners, BED has been consistently working on its strategic objective to "ensure all programs are equitable and accessible, with a priority given to low-to-moderate income, rental, black, indigenous, and people of color (BIPOC), immigrant, and refugee populations." If all customers have equitable opportunities to participate in our energy services, our City-wide energy goals become more attainable.

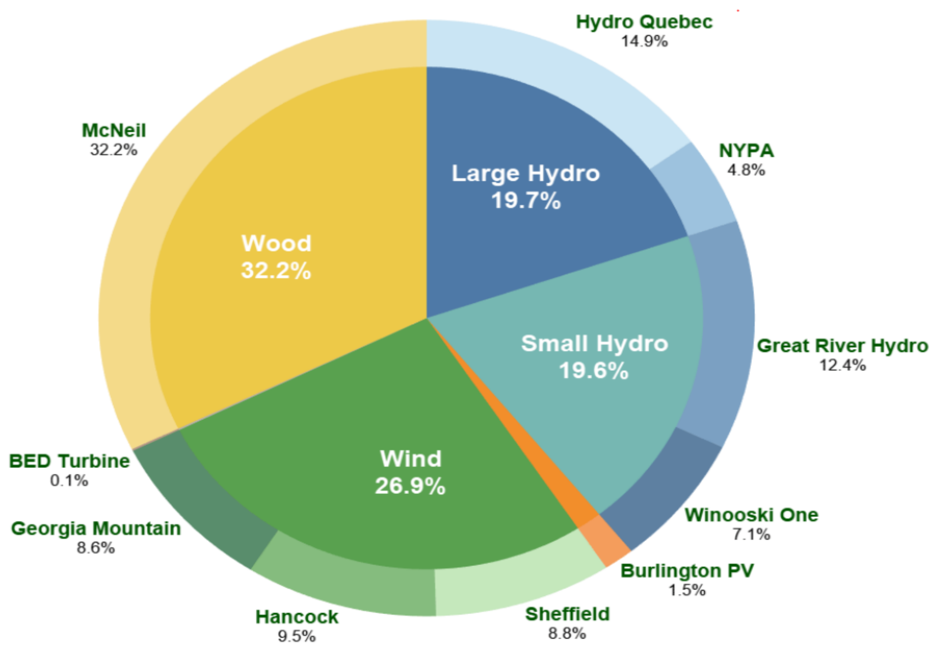
Utility Facts

The following facts about BED provide additional context for the IRP and BED's aggressive clean energy goals that reflect the community's environmental ethos.

- Burlington Electric Department was first established in 1905 as a municipal utility to lower the cost of electricity for residences and the City's streetlights.
- The total population of Burlington is approximately 44,743.[6] The City is widely considered to be the economic, cultural, and educational hub of the State of Vermont, as many Vermonters and tourists commute into the City to work, shop, and attend events.
- BED serves approximately 21,600 customers: 17,700 residential customers and 3,900 commercial customers.
- BED's service area spans approximately 16 square miles, including the Burlington International Airport.
- BED is rated A3 (stable) by Moody's Investors Service (as of August, 25, 2021). This rating is attributed to a diverse local economy and strong demand base, competitive electric rates, and diverse, renewable power supply.
- BED is the majority owner (50%) and operator of the Joseph C. McNeil Generating Station ("McNeil Station"), a 50 MW biomass-fired steam generation plant that commenced operations in June 1984. In 2008, the McNeil Station's joint owners installed state-of-the-art pollution control equipment that reduced local NOx emissions and allowed for the sale of high-value renewable energy credits ("RECs"). With the proceeds from REC sales, BED was able to achieve a two-year payback on its investment in pollution controls.
- With BED's purchase of the Winooski One hydroelectric facility in 2014, the City of Burlington's 15-year quest to source 100% of its electrical needs from renewable resources was achieved. Importantly, BED is recognized as being 100% renewable post-REC sales and purchases as well.
- BED's generation mix (before REC sales) includes biomass, large hydro, small hydro, wind, and solar, as shown in Figure 0-3.

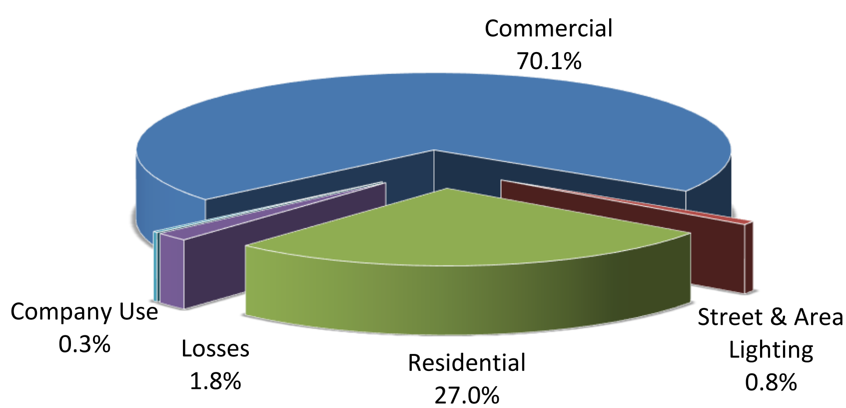
[6] US 2020 Decennial Census.

Figure 0-3: BED Energy Supply by Source (2022)



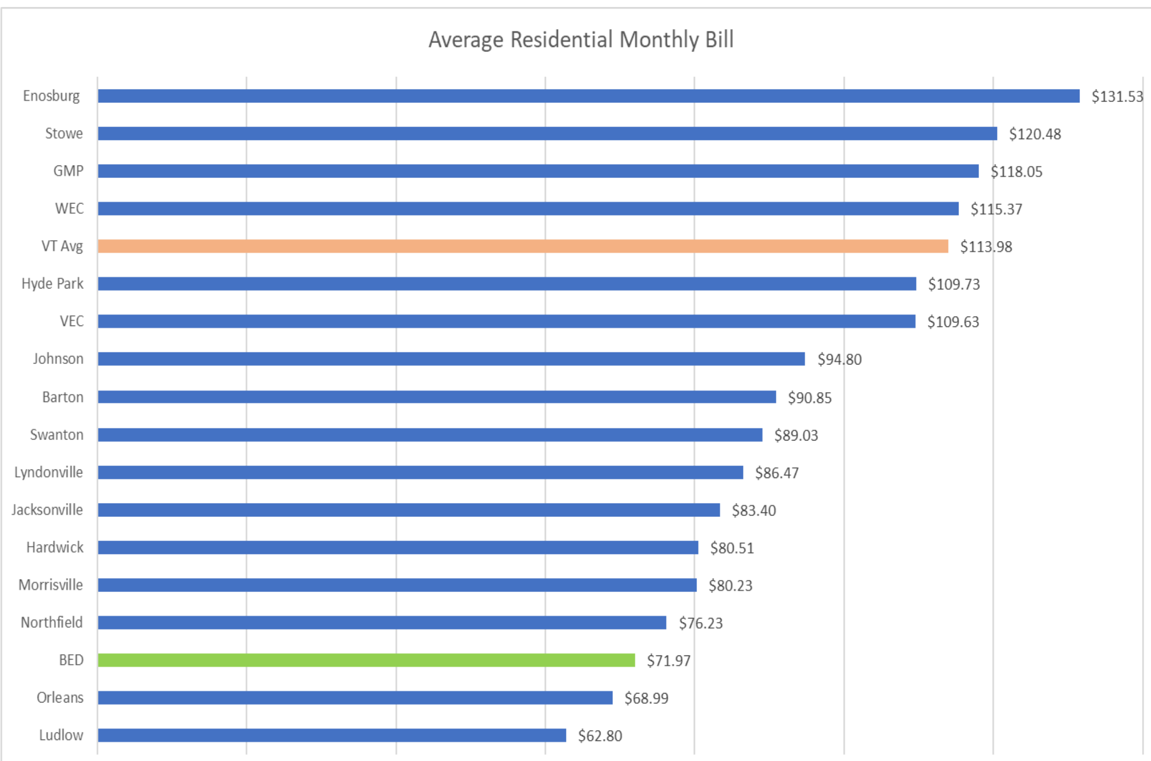
- In 2022, BED's total energy use (including losses) amounted to 327,660 MWh, a 4% increase over pandemic-impacted 2020 when BED submitted its last IRP. Peak demand reached 63.29 MW (summer). Despite the increase, energy use has been declining annually over the last 10 years by as much as 0.7%. Reductions in sales can largely be attributed to changes in the general economy, strong energy efficiency programs, and new appliance standards.
- Commercial customers account for the largest share of BED's electricity use, nearly 70% of the total. Residential customers account for roughly 27% of total energy requirements as shown in Figure 0-4.

Figure 0-4: 2022 System Energy Requirements



- BED's 20 largest commercial accounts account for nearly 50% of the city's total energy load.
- On average, most residential customers use less than 427 kWh per month and incur $72 in monthly electric bills[7] – about the same as a typical cellular telephone bill.
- In 1990, the City of Burlington's voters approved an $11.3 million BED revenue bond to fund demand-side management programs, making BED the first "energy efficiency utility" in the state.
- Electric use since 1960 has increased 2.2% annually, although this growth has not been uniformly distributed over time.
- Investments in energy efficiency over the last 20 years have helped to essentially flatten load growth.
- 60% of BED's residential customers rent their homes.
- 70% to 75% of BED's commercial customers lease their building space.
- Because a high percentage of BED's customers are college students, 35% of BED's accounts turn over to new customers each year.
- As shown in Figure 0-5, in 2022, the average BED monthly residential bill amount of roughly $72 per customer was the third-lowest in the state.[8]

Figure 0-5: Average Monthly Residential Electric Bill by VT electric utility, 2022



[7] See BED's EEU efficiency charge filings, Case 23 – 1985.
[8] Source data compiled from VEIC's Energy Efficiency Charge reports; see Case No. 23 - 1985.

2020 IRP Memorandum of Understanding

As a condition for approval of its 2020 IRP[9], BED agreed to:

a) Engage the Department of Public Service ("Department" or "DPS"), beginning at least six months prior to the IRP filing deadline, to discuss IRP methods, contents, and to share drafts. BED and the Department recognize that timely prefiling engagement by all parties can expedite preparation of the plan and contribute to the Department's timely review of the IRP, and;
b) BED will update the "Economic Impact of McNeil Station" study for its next IRP.

BED affirms that it has been meeting with the Department regularly since January 2023 to discuss IRP methods and contents and to share preliminary drafts of each IRP chapter. Also, an updated "Economic Impact of McNeil Station" report is included as an Appendix to this IRP.

Summary of Key Findings

Burlington's Demand for Electricity

Long-term energy requirements and peak demand forecasts are essential inputs into the planning process. The output from these analyses informs BED on the range of total energy and capacity that may be needed to provide reliable electric service. For this IRP, energy and capacity forecasts are based on statistically adjusted end-use models, developed by ITRON, that rely on historical data related to regional economic growth, weather patterns, seasonality, net metering generation, housing starts, business formation, and customer usage and behaviors. The MWh sales forecast includes projected sales of EVs and heat pumps as customers adopt these technologies over time.

As shown in Table 0-1, BED's base case scenario energy requirements are expected to remain relatively flat, increasing by 0.6% annually (after accounting for the effects of future energy efficiency programs, electrification, and behind-the-meter generation). Meanwhile, peak demand is expected to increase 0.5% annually by 2042.

Table 0-1: Annual Energy Requirements & Peak Demand, 2019-2039

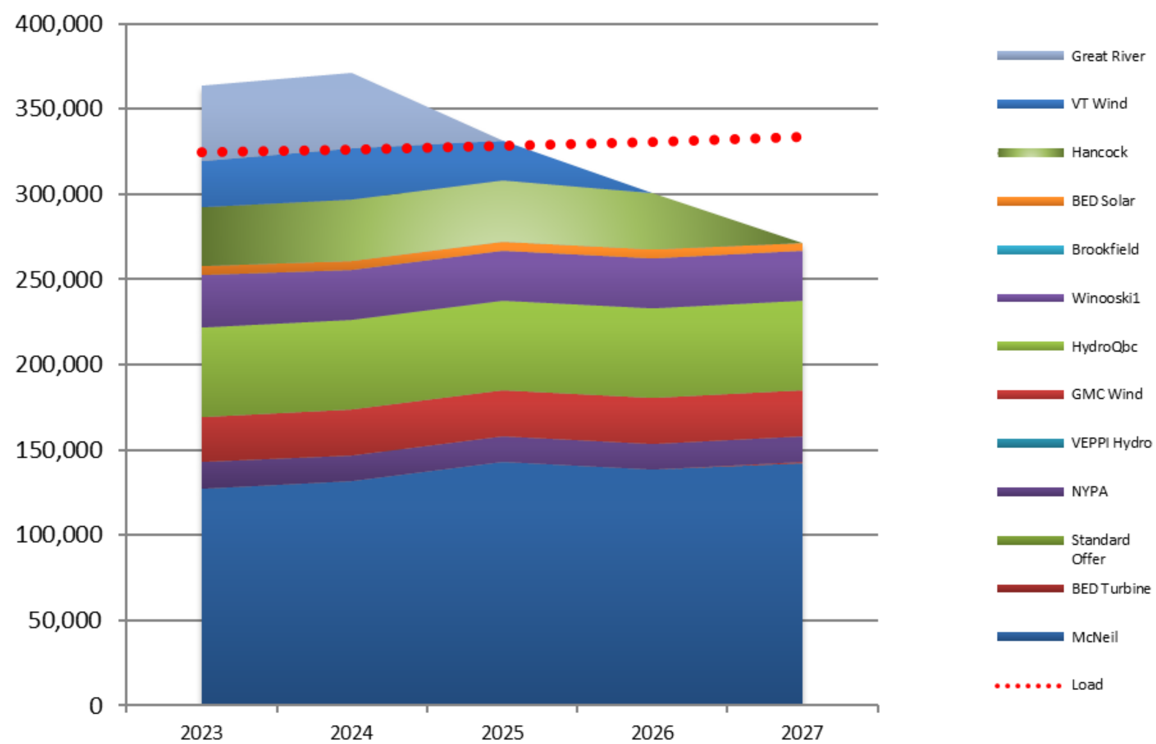
	2022	2027	2032	2037	2042	CAGR
Residential	88,513	95,785	106,289	116,993	130,878	2.0%
Commercial & Industrial	229,576	226,114	225,962	226,476	230,796	0.0%
Street Lighting	2,066	2,159	2,159	2,159	2,159	0.2%
Losses & Co. Use	7,505	7,176	7,233	7,433	7,841	0.2%
Total Energy Use (MWh)	327,660	331,134	341,543	352,962	371,573	0.6%
Peak Demand (MW)	63.29	63.6	65.8	67.5	69.9	0.5%

[9] Case 17-0638, Petition of BED for approval of its 2016 Integrated Resource plan, final order of 11/15/2017.

Generation & Supply Alternatives

Under base case assumptions, BED anticipates that its need for energy will exceed existing owned and contracted energy resources by 2025 even absent NZE activities due to contract expirations rather than load growth. Prior to 2025, BED possesses sufficient renewable energy to meet or exceed its base case load projections. BED will need to supplement its energy resources through new power agreements beginning in 2025 to retain its 100% renewability. Absent such action, purchase of energy in the spot market would occur "automatically" but would not represent renewable energy. As illustrated in Figure 0-6, the energy gap results from expiration of the Great River Hydro contract in 2024. Extensions of existing contracts are a distinct possibility.

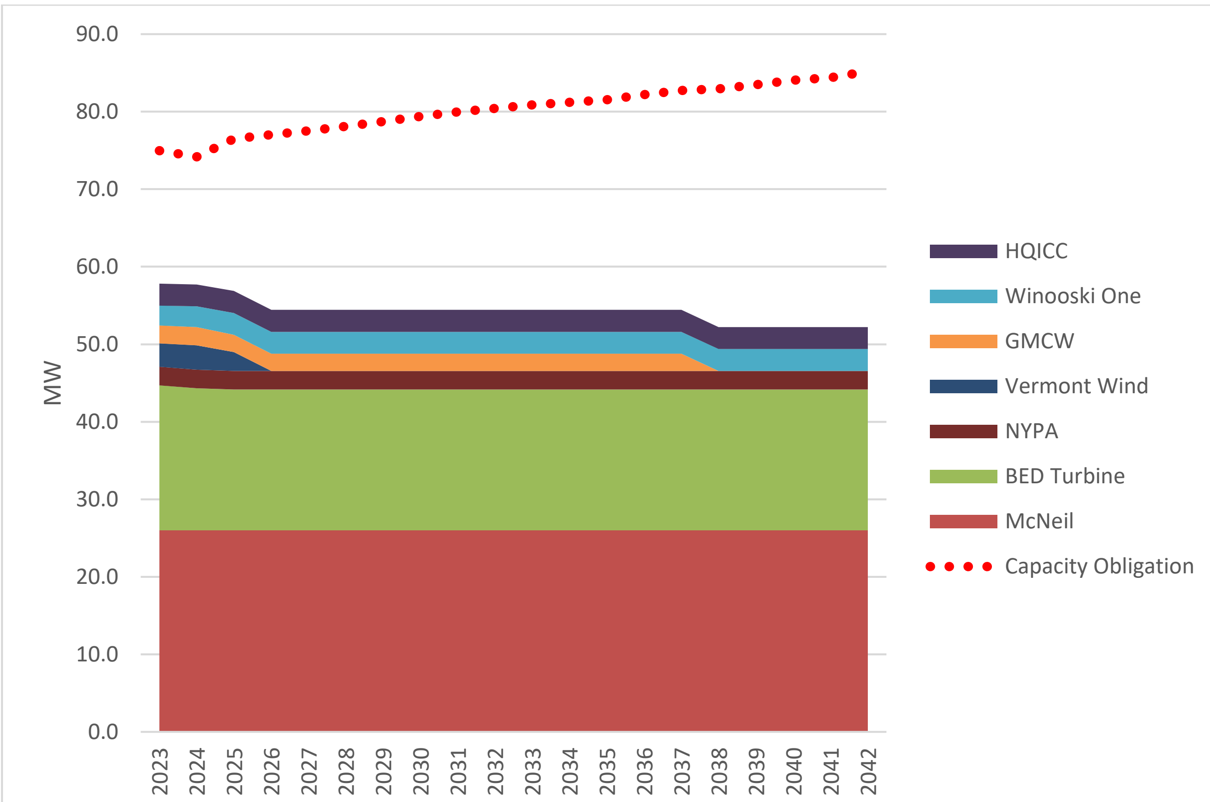
Figure 0-6: Forecasted Load v. Projected Supply Resources as of June 2023



Presently, BED either controls or contracts for capacity resources that are sufficient to satisfy approximately two-thirds of its capacity obligation, inclusive of the 15% reliability margin imposed on all distribution utilities by the Independent System Operator-New England ("ISO-NE"). Of the resources that BED controls, two facilities provide most of our capacity resources: BED's 25 MW share of the 50 MW McNeil Station and BED's 25 MW gas turbine.

As shown in Figure 0-7, BED's capacity obligation is approximately 75 MW today but grows slightly to about 85 MW over the next several years. Thereafter, our capacity obligation is expected to remain relatively flat, unless customer adoption of beneficial electrification measures exceeds current expectations. BED's capacity position is similar to that of many Vermont distribution utilities and we anticipate the capacity shortfall will persist. Potential means of addressing this shortfall include contracting for energy that includes the associated capacity, building another traditional peaking facility like BED's existing gas turbine, or, perhaps most promisingly, exploring the potential for capacity provided by battery storage technologies.

Figure 0-7: BED Projected Capacity Position as of June 2023



Transmission & Distribution

BED is committed to providing the highest system reliability, power quality, and system efficiency to its customers, and has excellent performance in this respect. This commitment is backed up by continual investments in distribution upgrades and process improvements to maintain BED's high quality of service.

Like other utilities, BED tracks power interruptions and outages. An interruption of power is considered an "outage" when an event exceeds five minutes. BED's system reliability is measured by the system average interruption frequency index ("SAIFI") and customer average interruption duration index ("CAIDI"), pursuant to Commission Rule 4.900. Each year, BED analyzes outage information on the City's distribution circuits, identifies the worst performing circuits, and then updates the distribution action plan accordingly to improve service performance across the system.

In 2022, BED's SAIFI was 1.06 interruptions per customer, significantly better than the service quality and reliability target performance of 2.1 interruptions per customer. BED's CAIDI in 2022 was to 0.67 hours, well below the target performance of 1.2 hours. Figures 0-8 and 0-9 below show historical data for BED's SAIFI and CAIDI, respectively. BED's system energy losses are extremely low as well, at just 1.83% on average. BED's reliability and system losses metrics are generally superior to those of any other Vermont utilities.

Figure 0-8: BED Historical SAIFI Values

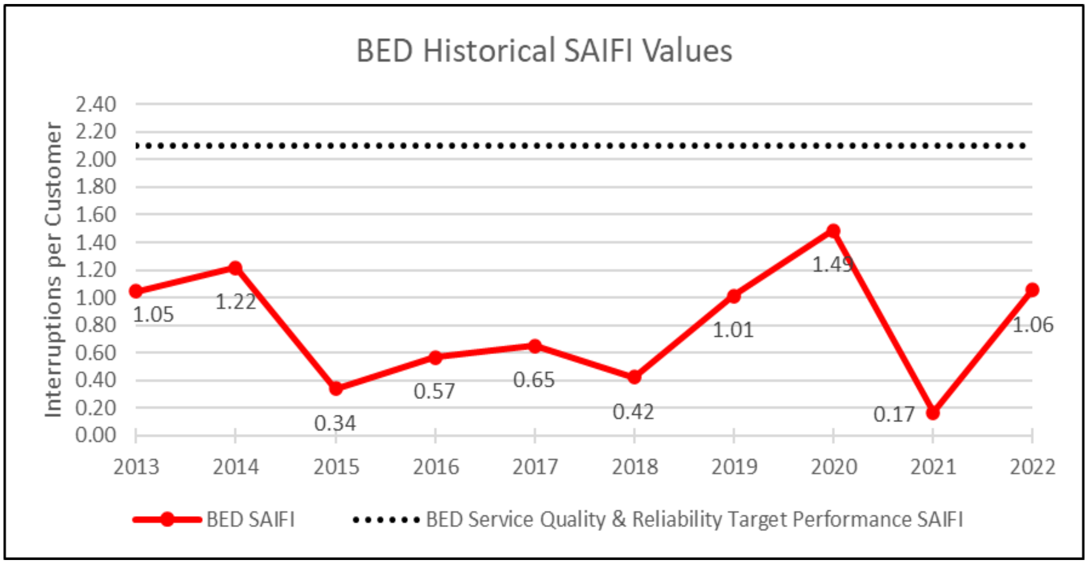
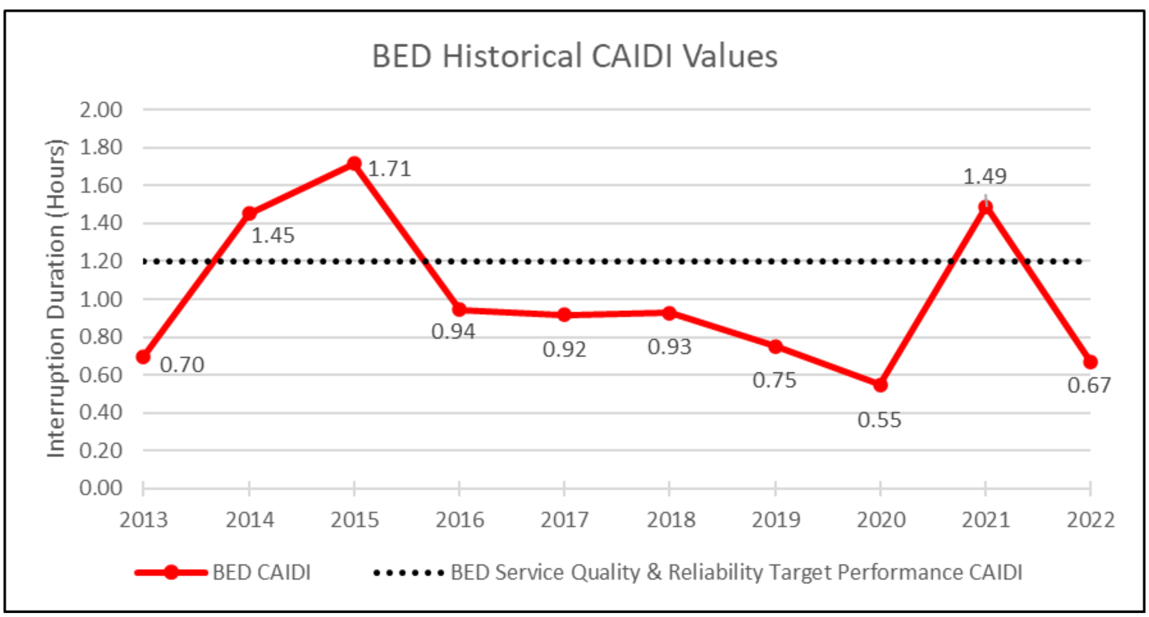


Figure 0-9: BED Historical CAIDI Values

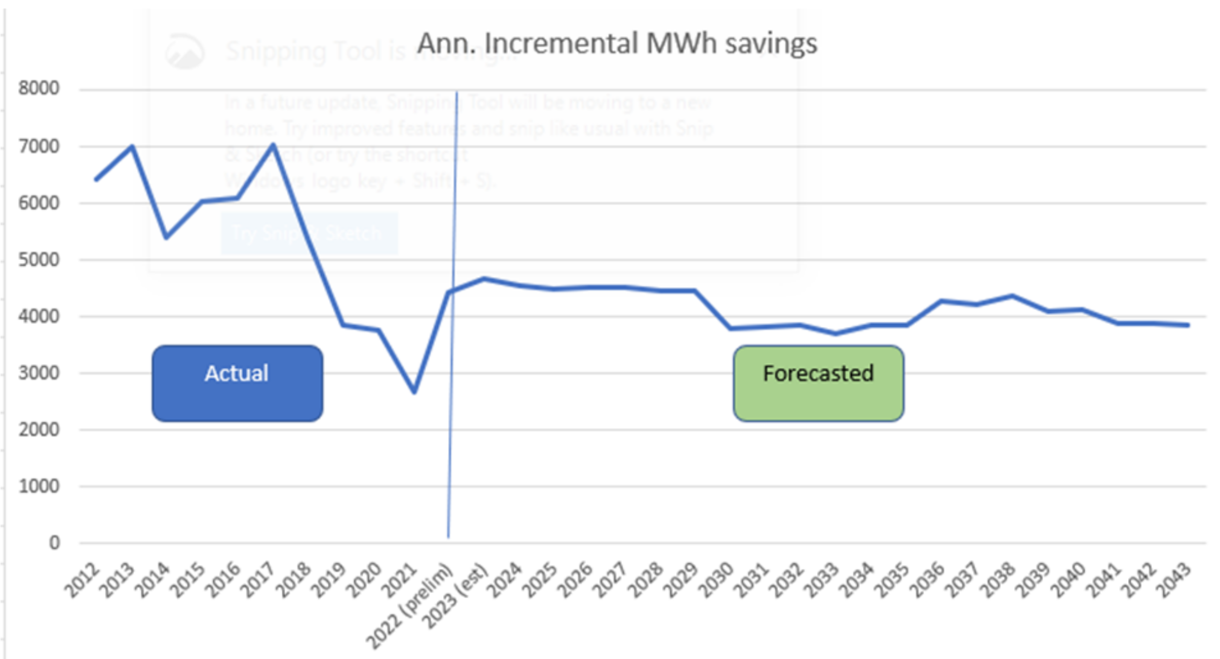


Comprehensive Energy Services

To effectively address the energy needs of our customers, BED combines traditional electric energy efficiency with beneficial electrification services in a comprehensive, customer-centric manner. Combining these services has multiple beneficial effects such as lowering the cost of traditional electric savings by spreading delivery costs over additional services, reducing greenhouse gas emissions while lowering customer's energy bills, and improving grid utilization as customers begin to consume electricity during off-peak times by managing the load impacts of strategic electrification.

With the recent approval of our 2024–2026 demand resource plan, BED expects its efficiency programs will reduce loads by roughly 4,500 MWh annually, as shown in Figure 0-10. The expected levelized cost of such savings should range between $0.04 and $0.06 per kWh.

Figure 0-10: Electric Energy Efficiency Historical vs. Forecasted Portfolio-Wide



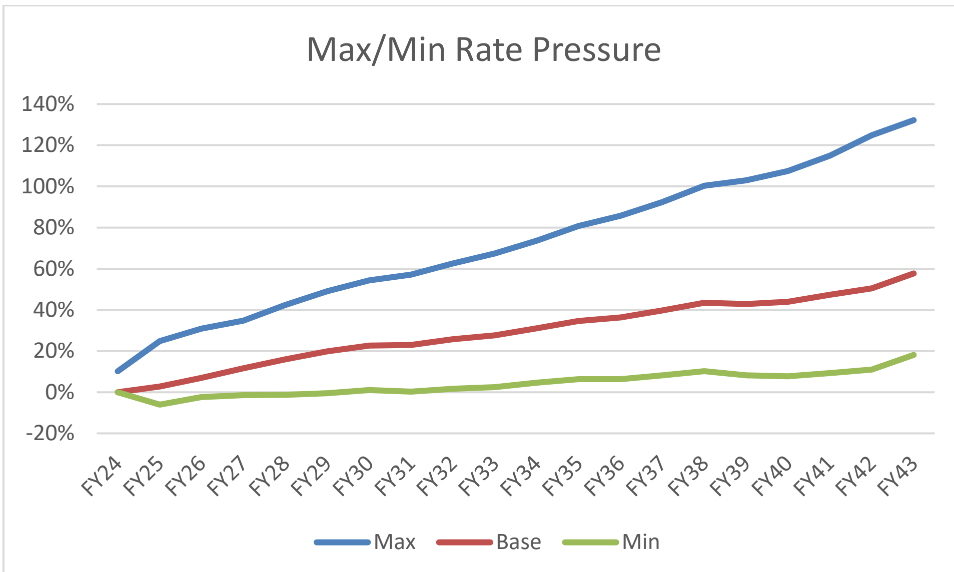
On the other hand, beneficial electrification programs may increase electrical loads if new technologies are adopted in significant numbers, potentially offsetting a portion of the forecasted savings. Under the base case scenario, however, BED does not expect adoption of such technologies to materially increase load in the near future.

Financial Assessment and Potential Rate Pressure

This chapter discusses the risks that could result in increased rates over time and BED's assessment of how much upward pressure each known risk could exert on electric rates. The primary risks evaluated were inflation; energy, capacity, and transmission costs; and REC values. Different combinations of these key variables change the level of pressure on BED's rates over time.

The potential range of rate pressures resulting from changes in our assumptions for these key risk variables are depicted in Figure 0-11, below. The "Max" line represents BED's assessment of the direction and magnitude of potential rate increases (or upward rate pressure) assuming all of the key variables trended toward the worst case scenario. The "Min" line represents the opposite. The compounding effect of changes in input risk variables could result in significant pressure to increase rates in the future, even with the substantial hedging that BED currently undertakes with respect to energy and RECs. On the other hand, the lowest potential pressure on rates would result from sustained high REC prices.

Figure 0-11: Potential rate pressure, FY24-FY43



This method of looking at cost pressures has the merit of recognizing that cost increases that are accompanied by increases in sales and thus revenue may actually reduce pressure on the need to increase rates. It also provides BED the opportunity to evaluate whether future decisions tend to increase or decrease rate pressure, as well as to understand which variables may be out of BED's control in whole or in part.

Decision Processes

In this chapter, BED addresses the complexity of achieving its dual objectives—complying with 30 V.S.A §218c regulations and assisting Burlington in transitioning to NZE—within an uncertain and dynamic environment. The chapter focuses on the decision-making process, with an evaluation of risks and decisions for behind-the-meter (BTM) energy storage as an illustrative example. It explains how BED would decide to proceed with such an investment based on the best available information. Additionally, it introduces a basic decision tree methodology for evaluating multiple concurrent decisions.

It is important, however, to note that BED does not attempt to use IRP decision methodology for all organizational decisions. Use of the level of rigor discussed in the Decision Processes chapter is particularly warranted when:

1. The decision is of a large magnitude
2. The decision is subject to significant uncertainty
3. Alternative competing options (including doing nothing) are viable as well.

Net Zero Energy Roadmap Implications

As in our 2020 IRP, this IRP contains an analysis of BED's incremental cost of service (and associated revenues) under two NZE scenarios. One scenario assumes that peak demand increases to 102.8 MW. The other assumes a 120 MW peak demand scenario.

As noted above, BED does not believe the current rate of beneficial electrification adoption will result in peak demand of more than 69.9 MW anytime soon. Nevertheless, our current NZE analyses confirmed our earlier analyses that despite the need for substantial distribution grid upgrades and increased costs for purchased power and transmission services, higher beneficial electrification adoption actually reduces pressure on BED to increase future rates as incremental revenues provide additional contributions toward existing fixed costs. Our NZE strategy also provides for greater opportunities to implement flexible load management programs that could potentially reduce regional transmission and peak demand costs, while increasing marginal revenues, provided end use rates for EVs and heat pumps are not discounted too steeply.

Although our conclusions are consistent with our previous findings in 2020, margins of additional contributions between the projected rate path and the costs to serve each MWh of load are reduced due to changing power cost levels and timing and increased construction costs associated with distribution upgrades. These updated conclusions underscore the importance of our key planning objectives to limit peak load impacts wherever possible, while also working with customers to increase the overall energy efficiency of their buildings and ground transportation needs. BED will also need to anticipate when increases in demand for power will occur and have in place a distribution network capable of reliably supporting that demand when it occurs.

Planning Priorities & Action Steps

Table 0-2 summarizes the priority actions that BED will take in the next several years, in accordance with our strategic plan:

Table 0-2: Action Steps

Functional Area	Priority Actions
Distribution & Operations	Continue to focus on normal capital replacement and improvement activities in support of system reliability and efficiency. Monitor any potential changes in peak load levels and load shapes to determine how beneficial electrification may impact BED's capacity to deliver the energy needs of our customers cost effectively. Implement a new advanced distribution management system ("ADMS").
Generation	Maintain and/or improve reliability of existing generating assets through maintenance programs. Investigate opportunities to improve the efficiency and value of our generating resources.
Power Supply & Planning	Maintain 100% renewability Seek options to renew and/or extend existing renewable energy contracts at favorable prices. Monitor the evolving market for storage for opportunities to deploy storage cost effectively within BED's service territory. Continue to monitor/participate in changes in tariffs and market rules that would impact the value of BED's resources. Continue encouraging customers to adopt beneficial electrification measures in support of NZE and to ensure equitable access to all electrification programs for all customers.
Energy Services	Focus on the delivery of comprehensive energy services aimed at reducing fossil fuel consumption and the greenhouse gas emissions associated with such consumption. Such delivery extends beyond traditional electric efficiency services to include technical assistance and incentives for beneficial electrification measures.

	Help customers address their building weatherization/thermal needs by coordinating services with VGS, where appropriate, or providing incentives through our weatherization partners to customers heating their buildings with nonregulated fuels or electric resistance technologies.
Customer Care/ Engagement	Provide service to customers that surpasses their expectations for meeting their energy-related questions and needs.
Finance & Rates	Continue to closely monitor financial performance inclusive of operational and capital budgets, credit rating factors, and other key financial indicators. Improve long-range financial forecasts to inform planning and decision-making. Continue to research the feasibility of implementing additional innovative rate designs.
Information Services	Continued conversion of core utility and business systems to more modern platforms under BED's "IT Forward" project. Continued cyber threat monitoring and enhancing BED's cybersecurity capabilities.
Sustainability & Workforce Development	Support and guide BED's various departments in designing new programs and identifying new opportunities to ensure that BED's efforts are equitable and accessible to all customers. Continue working with partner organizations dedicated to workforce training and development.
Safety, Risk Management, and Facilities	Continued investment in BED equipment and facilities in support of NZE. Maintain a safe working environment and manage exposures to risks through insurance products and other mitigation techniques. Participate in the risk assessment related to pilot projects and devices.
Net Zero Energy & other Pilot program research	Advance the City's NZE goal by working collaboratively with City and State officials and other stakeholders to establish effective supporting policies and regulations. Pursue several new and existing innovative products and services to better serve our customers, particularly in the area of flexible load management.

1. Burlington's Demand for Electricity

Burlington Electric Department ("BED")'s 2023 Long-Range Energy and Demand Forecast for this Integrated Resource Plan ("IRP") informs BED's resource planning to meet the forecasted total annual consumption of electric energy. The system energy forecast is made up of forecasted 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, expressed in terms of kilowatt-hours ("kWh"), megawatt-hours ("MWh"), or gigawatt-hours ("GWh"). BED's projected load requirements are also based on the expected maximum rate of use of electricity ("peak demand"), measured in kilowatts ("kW") or megawatts ("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 may need to be curtailed to prevent overloads and/or system failure.

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

Table 1-1: Base Case Annual Energy Requirements & Peak Demand, 2022-2042

	2022	2027	2032	2037	2042	CAGR
Residential	88,513	95,785	106,289	116,993	130,878	2.0%
Commercial & Industrial	229,576	226,114	225,962	226,476	230,796	0.0%
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Peak Demand (MW)	63.29	63.6	65.8	67.5	69.9	0.5%

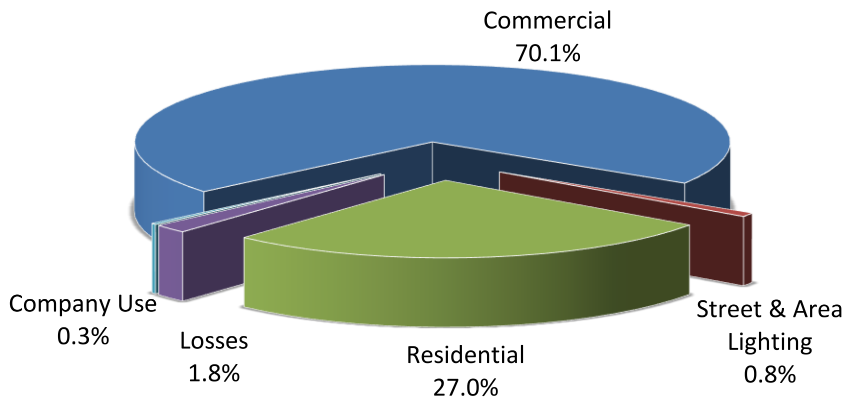
Over the next 20 years, base case system energy requirements average 0.6% annual growth with annual residential customer growth of 0.5%. Peak demand increases 0.5% annually over this period. In comparison, since 2010, both system energy and peak demand have declined on average 0.7% annually. Positive forecasted energy requirements are largely the result of expected electric vehicle ("EV") sales growth, electrification of bus service, and cold climate heat pumps in the second half of the forecast period.

Background

BED provides electricity in its service territory of the City of Burlington, approximately 16 square miles, as well as the Burlington International Airport located in South Burlington. BED is the third largest utility in Vermont, accounting for 6.1% of the state's total retail kWh sales.

BED currently serves approximately 17,700 residential and 3,900 commercial customers. BED's customers required 327,660 MWh of electricity during 2022, including roughly 320,779 MWh in sales with distribution losses and company (i.e., BED) use making up the remainder. The commercial customers account for the largest share of electricity use, with 70% of the total (Figure 1-1). The residential class accounts for 27% of the total energy requirements.

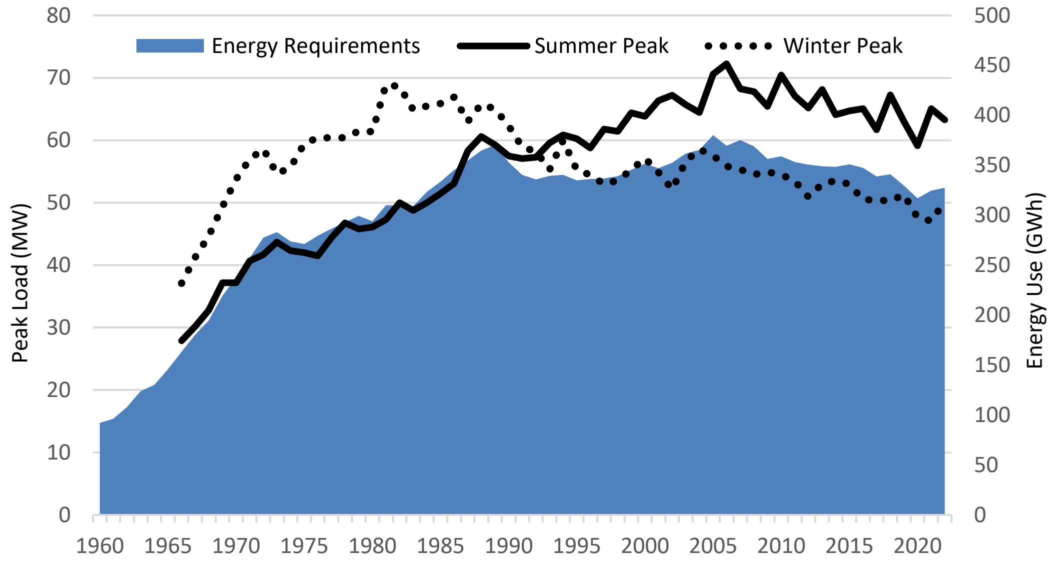
Figure 1-1: 2022 System Energy Requirements



Over the last 10 years, BED's total kWh sales have been declining at a rate of 0.7% per year. This is a trend throughout Vermont and across much of the country. Utility efficiency programs have suppressed demand in all sectors, and federal energy efficiency programs such as the Energy Policy Act of 2005 ("EPAct2005") and the Energy Independence and Security Act ("EISA 2007"), have also played a key role in reducing energy use over this period. Figure 1-2 provides the long-term electricity use trends in Burlington. Overall, total electricity use in Burlington has increased by 2.2% 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, and this promoted "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 an average rate of 10% per year during this period.

Figure 1-2: Historical BED 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 BED and to fundamental demographic changes and changing economic conditions.

In 1993, Burlington's annual peak demand occurred during the summer instead of the winter for the first time. Beginning in the mid-1980s, winter peak demand began to decline with 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, BED has 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, which is largely driven by air conditioning. Figure 1-3 shows the 2022 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. In 2022, the maximum hourly demand occurred on August 30. The highest demand for electricity during the winter months occurred on January 29.

Figure 1-3: 2022 Hourly BED System Net Demand

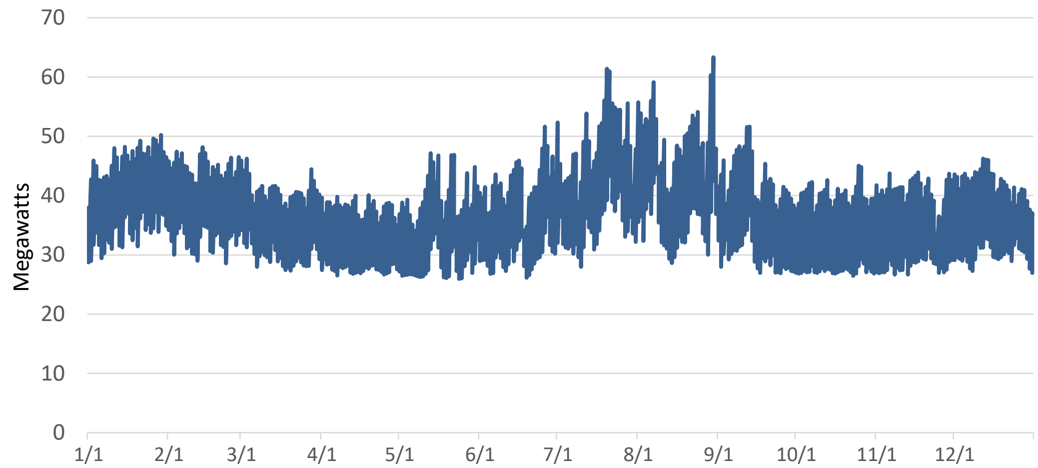
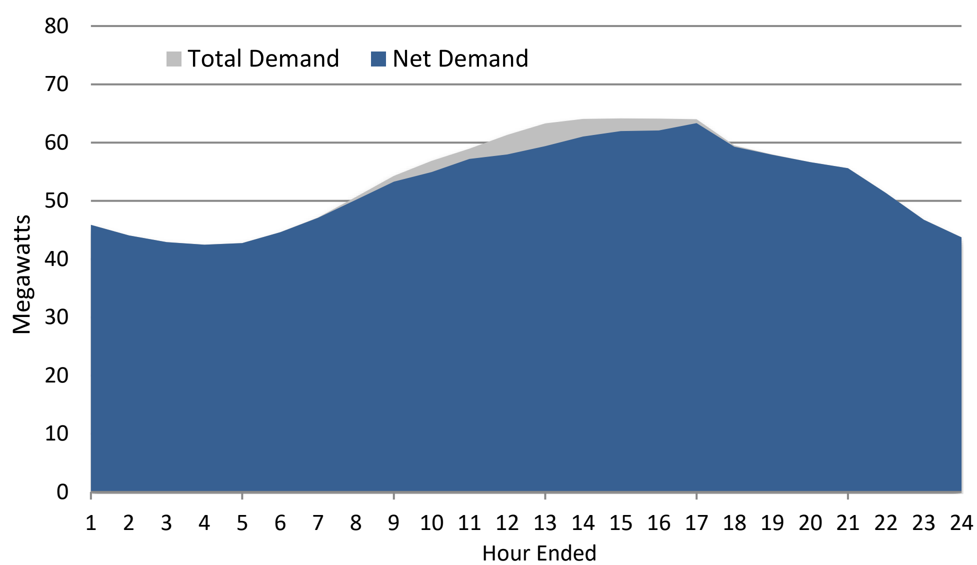


Figure 1-4 provides a view of the BED's hourly demand on the summer peak day in 2022. The summer peak day is characterized by load rising gradually until the early afternoon, reaching a peak period, and gradually declining after 5 pm. The summer peak demands occur most often between 2 and 5 pm, on days when the average daily temperature exceeds 80 degrees Fahrenheit. Burlington averages about three to four days per year with average daily temperature higher than 80 degrees Fahrenheit. During the summer of 2022, average daily temperatures in Burlington exceeded 80 degrees on three different days and were exactly 80 degrees on three other days.

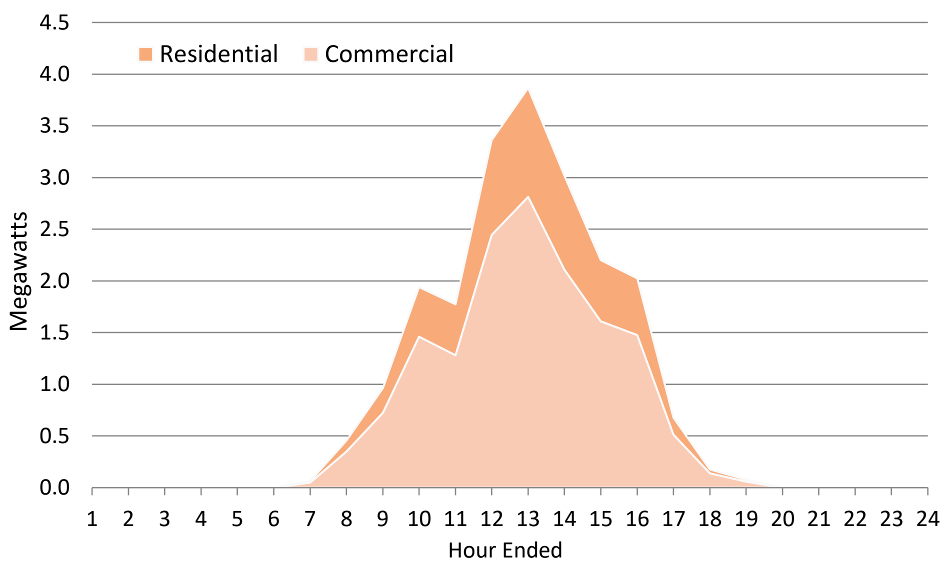
Figure 1-4: BED System Demand on August 30, 2022 (Peak Day)



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 August 30, 2022, the maximum system demand reached 64.14 MW at hour ended 3:00 pm. The maximum ***net*** demand (excluding the customer behind-the-meter generation) was 63.33 MW, however, occurring at hour ended 5:00 pm. The behind-the-meter solar generation reduced the system peak demand by 0.81 MW and shifted the peak hour from hour ended 3:00 pm to hour ended 5:00 pm.

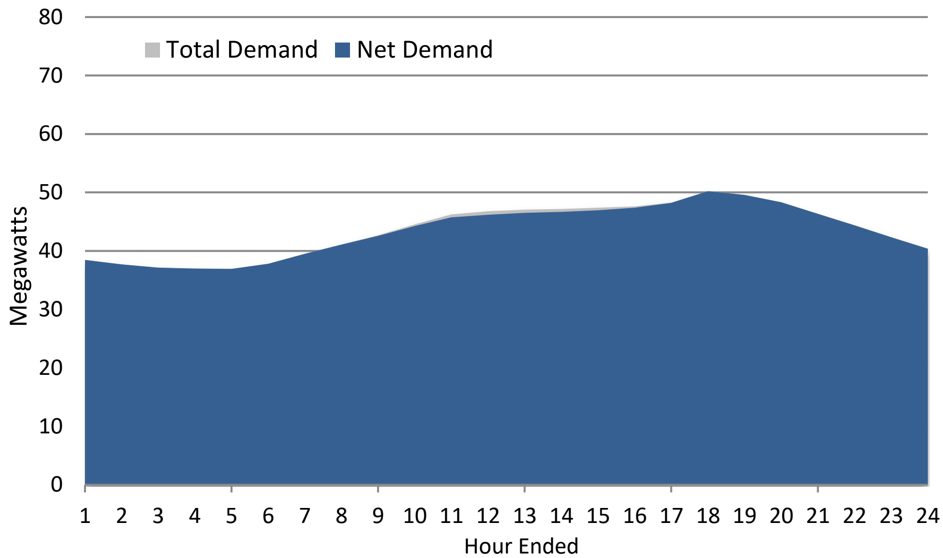
Figure 1-5 shows the total customer-owned behind-the-meter solar generation in Burlington on August 30, 2022.

Figure 1-5: BED Behind-The-Meter Solar Generation on August 30, 2022



During the winter months, on weekdays the system load increases rather abruptly in the morning, peaking 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 1-6 shows the BED's hourly demand on the winter peak day in 2022, January 29. Because this was a Sunday, the load shape is slightly different, without a drop during the midday hours.

Figure 1-6: System Demand on January 29, 2022 (Winter Peak Day)



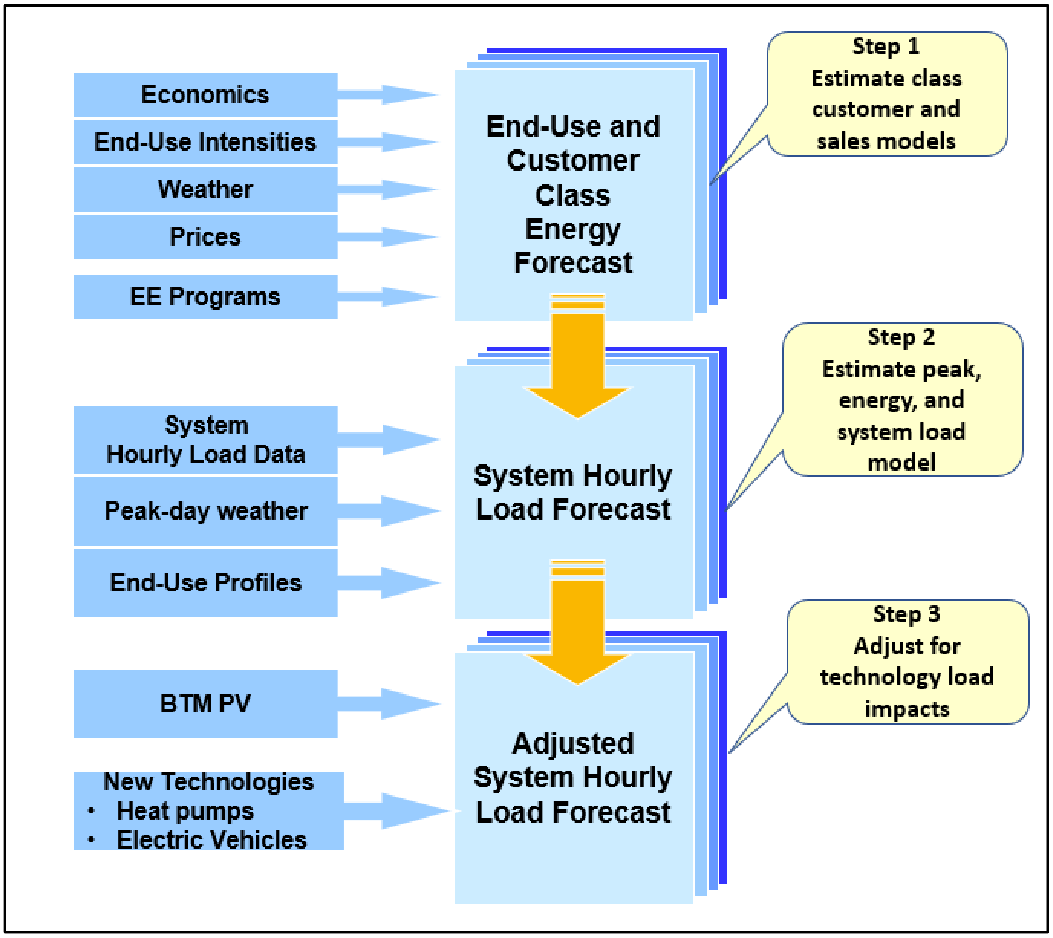
Forecast Approach

BED contracted with Itron, Inc. ("Itron") to develop a 20-year energy and demand forecast to support the IRP planning process.[10] The forecast was developed using the same methodology that was approved in BED's previous IRP, except that impacts from EV and cold climate heat pump adoption were 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 class 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 1-7 illustrates the modeling approach.

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

Figure 1-7: 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.

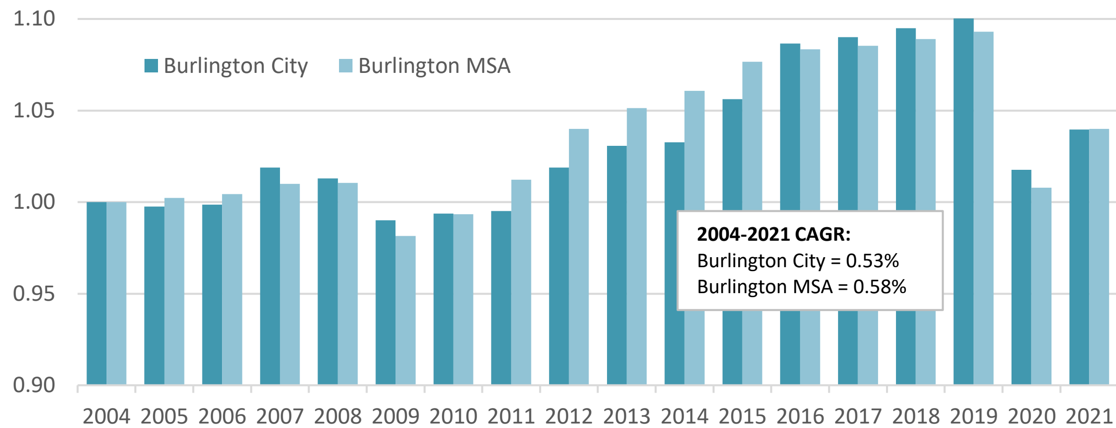
The residential and commercial forecast models were based on "reconstituted" monthly sales, where all behind-the-meter solar PV impacts were added back to the monthly billed sales. After the individual monthly forecasts were produced, the system load shape was adjusted to account for the impacts of existing 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, household income and number of new households were the primary drivers. In the commercial sector, regional output (gross metropolitan area 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 1-8 compares the total employment growth rates for the City of Burlington and the Burlington MSA for the recent 17-year period. The year-to-year change and overall growth over the period was very similar.

Figure 1-8: Total Employment Growth by Region (2004 = 1.0)



BED's projected data is weather-normalized. Historical daily weather data was available for the Burlington weather station at the Burlington International Airport for the period January 1976 to December 2021. Degree days trends were calculated using this data from the period 1989 to 2021. 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. For the commercial sector, cooling degree days were calculated with a 55-degree base and heating degree days with a 50-degree base.

The residential sector incorporates appliance 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 residential 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, 80% of future efficiency savings is estimated to be embedded in the model, so the efficiency trend is adjusted downward by 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 advanced metering infrastructure ("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, an increasing number of customers have installed solar photovoltaic generating systems in Burlington.

Class Sales Forecasts

Changes in economic conditions, prices, weather conditions, as well as efficient 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.

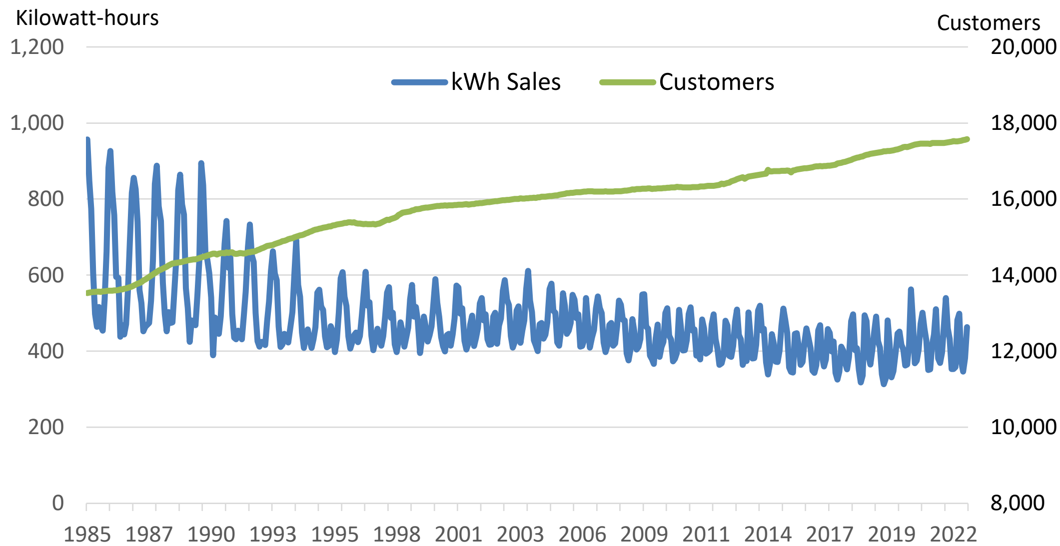
- Residential
- Commercial/Industrial
- Street Lighting

Residential Sector

The two main drivers of the residential forecast are the forecast number of residential customers and the forecast 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 1-9 shows the number of customers and the average monthly kWh use per customer for Burlington's residential sector for the period 1985 to 2022. Burlington has seen steady growth of 0.6% per year on average in the number of residential customers over the last 5 years, including a year of low growth in 2021 (likely due to the effects of the COVID-19 pandemic). Excluding 2021, the average annual growth in number of residential customers from 2017 to 2022 is 0.76%. For the 15 years prior, the number of BED residential customers grew by only 0.4% per year on average. Average monthly kWh use per customer, however, has fallen more than 35% from 7,666 kWh use per customer in 1985 to 5,040 kWh use per customer in 2022, due to energy efficiency, changing codes and standards, fuel switching, and end-use trends. The decrease has been particularly strong across the winter season, reflecting the impact of fuel switching and lighting efficiencies on usage.

Figure 1-9: Residential Monthly Average kWh Use & Number of Customers

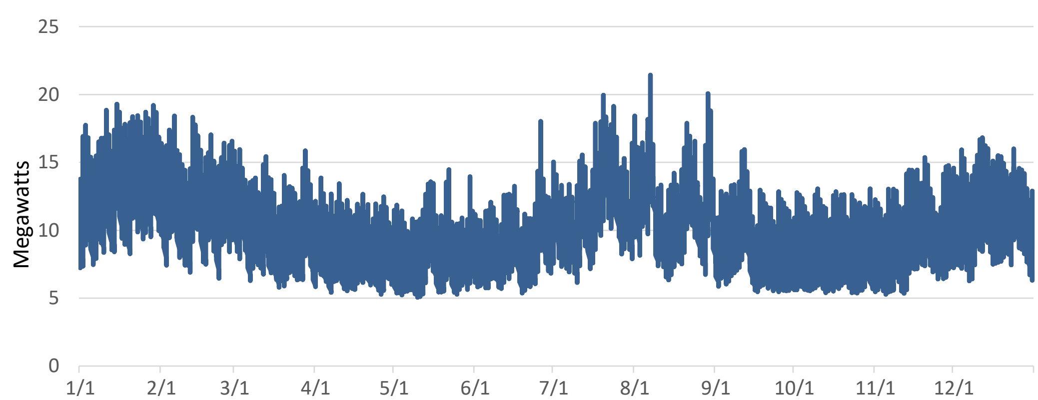


The development of residential net-metering facilities also impacts residential customer use calculations. By the end of 2022, there were 390 residential net-metering customers having a combined solar capacity of 1.8 MW. The total solar PV generation in 2022 was 1,629,009 kWhs, lowering the average annual residential use per customer by 93 kWh (1.8%).

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 1-10, which displays the residential hourly load profile for 2022.

Figure 1-10: 2022 Residential Hourly Net Demand



During 2022, the residential sector reached its highest (net) demand of 21,427 kW during the hour ended 7:00 pm on August 7 (which was not the system peak day). The residential sector's maximum demand in the winter was 19,291 kW on January 15 at hour ended 7:00 pm.

Figure 1-11 and Figure 1-12 provide the residential sector "typical day" load profile plots for the summer and winter seasons in 2022. On average, residential loads tend to increase sharply during weekday mornings until around 8:00 am, followed by a leveling 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 MW higher than the average levels.

Figure 1-11: Residential Typical Day – 2022 Summer (Jun-Aug)

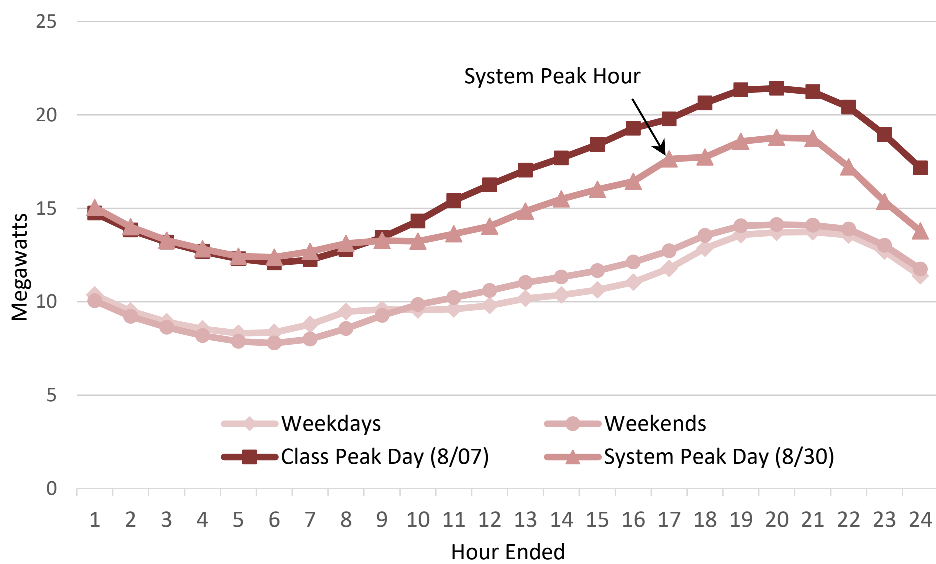
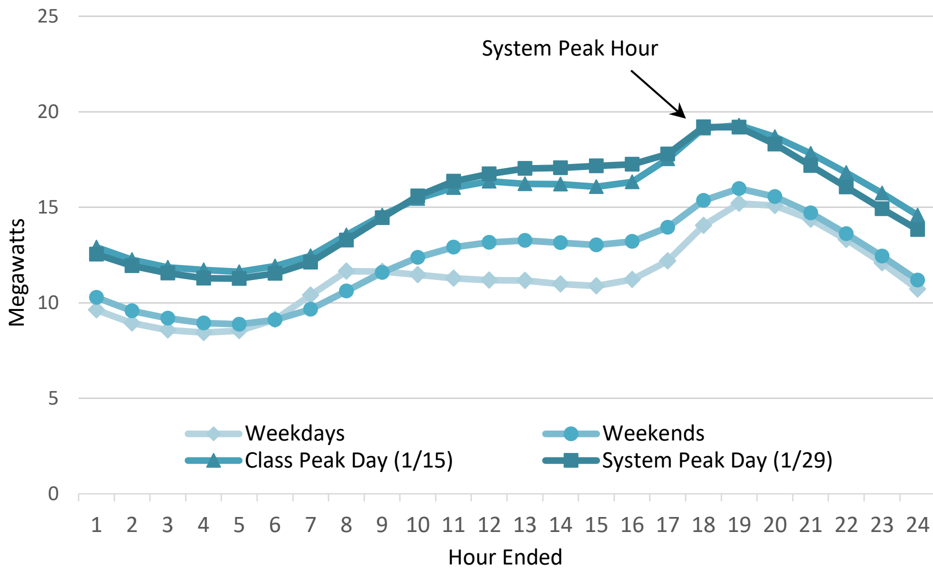


Figure 1-12: Residential Typical Day – 2022 Winter (Jan-Mar)



Residential Sales Forecast

As described above, 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 an annual equipment index variable by a heating use variable. The equipment 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 equipment index variable by a cooling use variable. The cooling equipment 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.

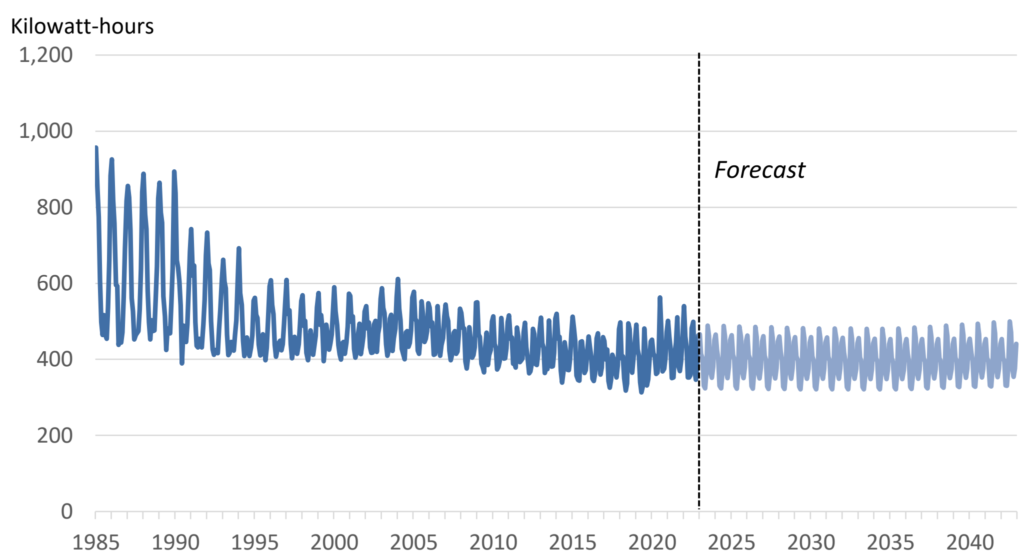
The Xother variable estimates the non-weather sensitive sales and is similar to the Xheat and Xcool variables. This variable incorporates information on appliance and equipment saturation levels, days per month, average household size, real personal income, and electricity prices.

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 November 2022. The SAE model is estimated using over the period January 2012 to October 2022.

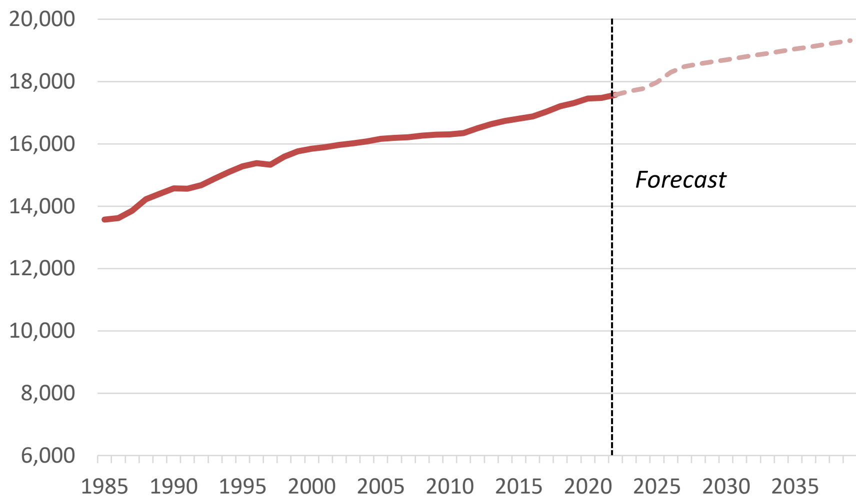
Figure 1-13 shows the residential average use forecast before making any adjustments for behind-the-meter generation and future EV or heat pump adoption. Average use bottomed out in 2017 and increased significantly in 2020 as the state implemented a work at home mandate in response to the COVID-19 pandemic. Since 2020, average use has been declining but a small rate. Average use is projected to remain at somewhat higher base level in the forecast period as a relatively large share of households continue to work from home.

Figure 1-13: Monthly Residential kWh Use per Customer Baseline Forecast



The forecast of Burlington's residential customers shown in Figure 1-14 is based on a monthly regression model using historical data from January 2012 to November 2022. The number of residential customers is forecasted using Burlington MSA housing unit projections as the major driver.

Figure 1-14: Residential Customer Forecast



Residential sales projections are then obtained by the combination of the customer projections and average use projections. With flat average use and 0.5% increase in customer growth, residential sales average 0.5% growth between 2023 and 2042. Table 1-2 displays the baseline annual residential sales forecast, excluding any impacts of behind-the-meter generation and EV and heat pump adoption.

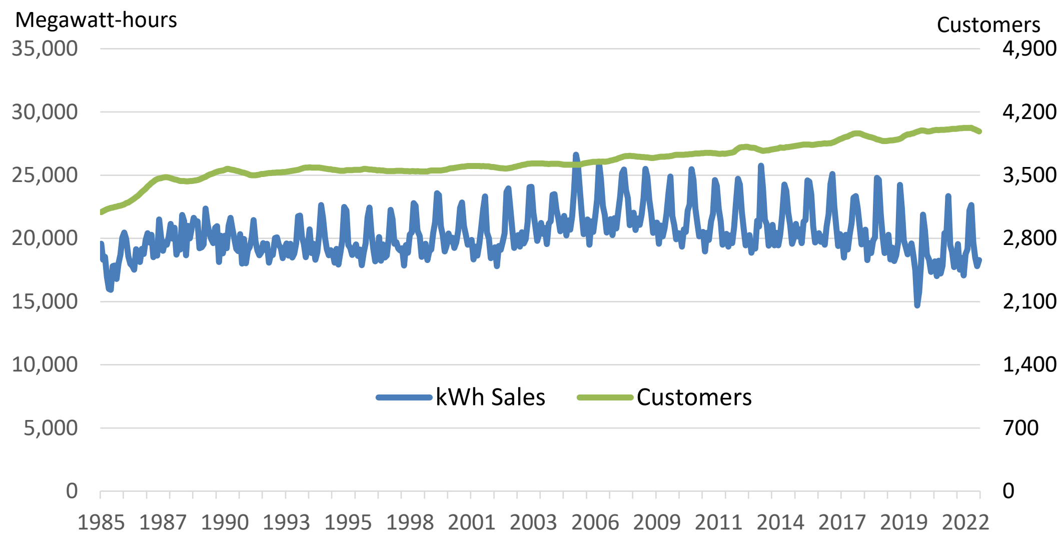
Table 1-2: Residential Sector Baseline Forecast (excluding PV and EV and HP impacts)

Year	Total Sales (MWh)	% Chg.	Customers	% Chg.	Avg. Use (kWh)	% Chg.
2023	87,070		17,696		4,920	
2024	87,500	0.5%	17,774	0.4%	4,923	0.1%
2025	88,104	0.7%	17,976	1.1%	4,901	-0.4%
2026	89,507	1.6%	18,293	1.8%	4,893	-0.2%
2027	90,189	0.8%	18,484	1.0%	4,879	-0.3%
2028	90,612	0.5%	18,559	0.4%	4,882	0.1%
2029	90,569	0.0%	18,633	0.4%	4,861	-0.4%
2030	90,857	0.3%	18,701	0.4%	4,858	-0.1%
2031	91,090	0.3%	18,769	0.4%	4,853	-0.1%
2032	91,545	0.5%	18,837	0.4%	4,860	0.1%
2033	91,564	0.0%	18,905	0.4%	4,844	-0.3%
2034	91,735	0.2%	18,973	0.4%	4,835	-0.2%
2035	92,069	0.4%	19,041	0.4%	4,835	0.0%
2036	92,778	0.8%	19,109	0.4%	4,835	0.4%
2037	93,131	0.4%	19,178	0.4%	4,856	0.0%
2038	94,358	0.7%	19,246	0.4%	4,870	0.3%
2039	94,358	0.7%	19,315	0.4%	4,885	0.3%
2040	95,125	0.8%	19,384	0.4%	4,907	0.5%
2041	95,433	0.3%	19,453	0.4%	4,906	0.0%
2042	96,008	0.6%	19,522	0.4%	4,918	0.2%
'23-'42		0.52%		0.52%		0.00%

Commercial Sector

BED's commercial sector includes Small General Service, Large General Service, and Primary Service customer classifications. In 2022, this sector accounted for only 18% of total customers but 70% of the total kWh-sales. Figure 1-15 provides monthly MW sales and customer history for the commercial sector. The steep decline in MW sales in 2020 is a result of the COVID-10 pandemic.

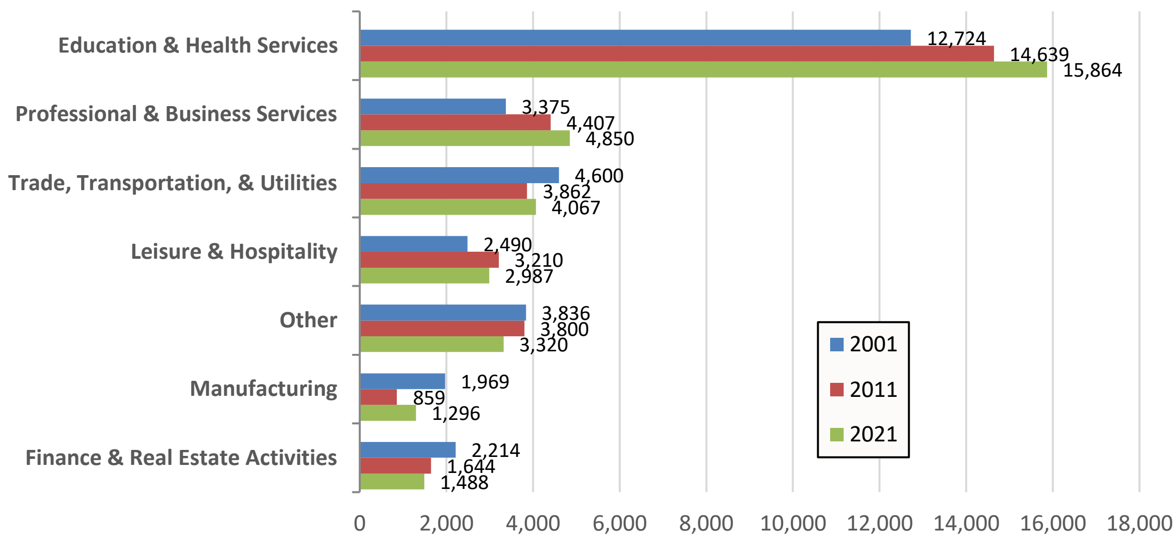
Figure 1-15: Commercial Monthly kWh Sales & Customers



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 the loss of several large manufacturing customers (between 1990 and 2006, and again in 2017 and 2021), changing economic conditions, and energy efficiency programs and standards. Commercial sales decreased significantly in 2020 due to the COVID-19 pandemic, and while there has been some recovery, sales appear to be leveling off. 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. Economic recessions also have 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. As of 2021, 3.8% of Burlington's jobs are in the manufacturing sector – down from 15.3% in 1980.

Figure 1-16 shows 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 1-16: Burlington City Employment by Sector[11]



There were 88 commercial net-metering customers by the end of 2022, having a combined solar capacity of 3.77 MW. The total commercial solar PV generation in 2022 was 4,540,474 kWhs, offsetting commercial sales by 2.0%.

Commercial Load Shape

Figure 1-17 provides a plot of the aggregate hourly load for the commercial sector for 2022. 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 44,499 KW on August 30, 2022, hour ending 2:00 pm, one hour earlier than the overall system peak hour.

[11] U.I. Covered Employment & Wages (vtlmi.info)

Figure 1-17: Commercial Sector: 2022 Hourly Load Profile

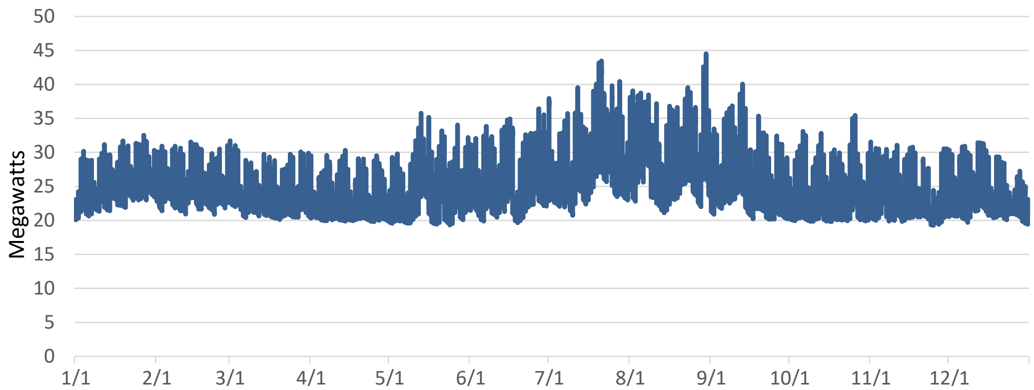


Figure 1-18 and Figure 1-19 provide the commercial sector "typical day" load profile for the summer and winter periods during 2022. During the weekdays, the commercial sector's load profile is characterized by one peak period, regardless of the season. During the day, loads increase sharply between 6:00 am and 12:00 pm, remain at high levels until about 4:00 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 1-18: Commercial Typical Day - Summer (Jun-Sep)

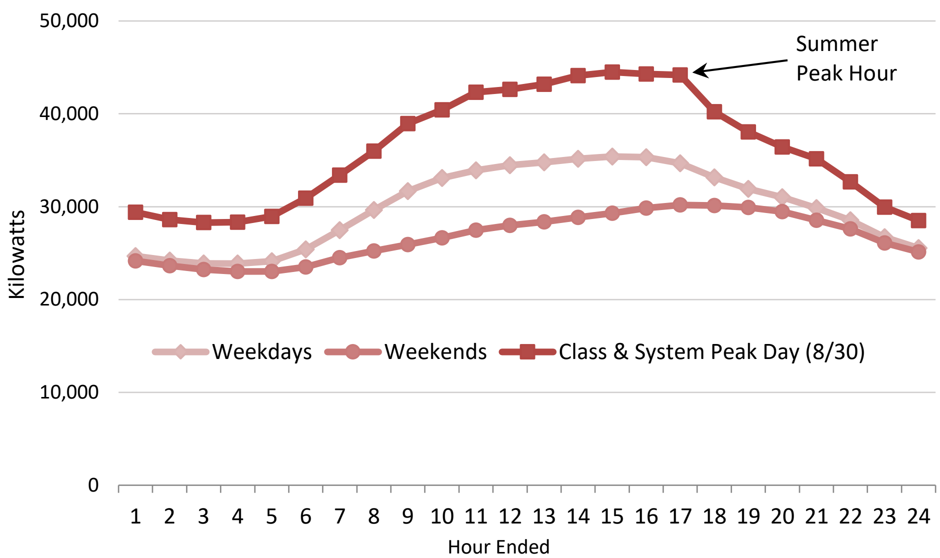
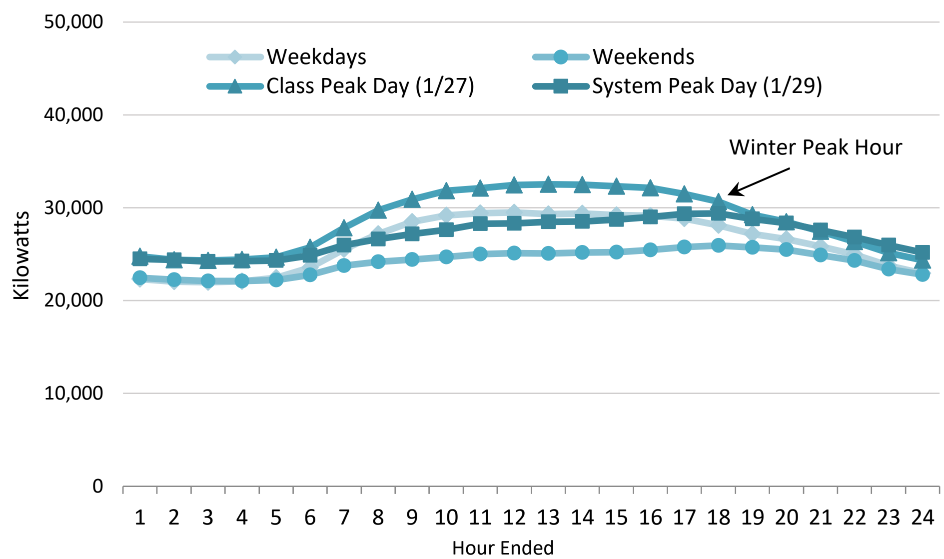


Figure 1-19: Commercial Typical Day - Winter (Dec-Mar)



Commercial Sales Forecast

Like the residential 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 equipment 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 2022 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 2012 through November 2022. As with the residential SAE model, the effects of EPAct, EISA, American Reinvestment & Recovery Act, 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 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 of larger businesses shutting down or moving out of the City (e.g., Burlington Town Center, G.S. Blodgett, Koffee Kup Bakery). It is expected that sales will eventually return as new customers occupy 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 adjustments to the forecast.

Commercial sales are relatively flat through the forecast period; improvements in end-use and building efficiency offset the impact of customer and economic growth. Table 1-3 shows the annual MWh sales forecast for the commercial sector, excluding any impacts from existing and future solar generation, EV adoption, and heat pump adoption.

Table 1-3: Commercial Sector Baseline Forecast (excluding EV, PV, and HP impacts)

Year	Total Sales (MWh)	% Chg.	Customers	% Chg.	Avg. Use (kWh)	% Chg.
2023	231,280		3,980		58,108	
2024	230,906	-0.2%	4,016	0.9%	57,490	-1.1%
2025	230,051	-0.4%	4,034	0.4%	57,026	-0.8%
2026	229,651	-0.2%	4,051	0.4%	56,695	-0.6%
2027	229,316	-0.1%	4,064	0.3%	56,426	-0.5%
2028	229,558	0.1%	4,076	0.3%	56,322	-0.2%
2029	228,658	-0.4%	4,087	0.3%	55,946	-0.7%
2030	227,878	-0.3%	4,098	0.3%	55,609	-0.6%
2031	227,232	-0.3%	4,108	0.3%	55,310	-0.5%
2032	227,284	0.0%	4,119	0.3%	55,181	-0.2%
2033	226,297	-0.4%	4,129	0.3%	54,802	-0.7%
2034	225,794	-0.2%	4,140	0.3%	54,540	-0.5%
2035	225,529	-0.1%	4,151	0.3%	54,337	-0.4%
2036	226,126	0.3%	4,161	0.3%	54,342	0.0%
2037	225,596	-0.2%	4,172	0.3%	54,077	-0.5%
2038	225,799	0.1%	4,182	0.3%	53,988	-0.2%
2039	226,076	0.1%	4,193	0.3%	53,917	-0.1%
2040	226,722	0.3%	4,204	0.3%	53,933	0.0%
2041	226,369	-0.2%	4,214	0.3%	53,713	-0.4%
2042	226,699	0.1%	4,225	0.3%	53,654	-0.1%
'23-'42		-0.10%		0.31%		-0.42%

Streetlighting

There are approximately 3,630 streetlights in the city of Burlington, and they accounted for less than 1% of total retail sales in 2022 (2,690 MWh). Since 2010, BED has increased efforts to replace streetlight fixtures with LED fixtures. As of 2022, more than 2,400 streetlights (67%) have been converted to or installed as LED fixtures, resulting in a decline in street lighting sales of more than 52% since 2010. Street lighting sales are fitted with a simple regression model driven by outdoor lighting energy intensity and seasonal variables. Between 2023 and 2042, street lighting sales are projected to be flat as the impact of new streetlight installations is mitigated by increasing efficiency.

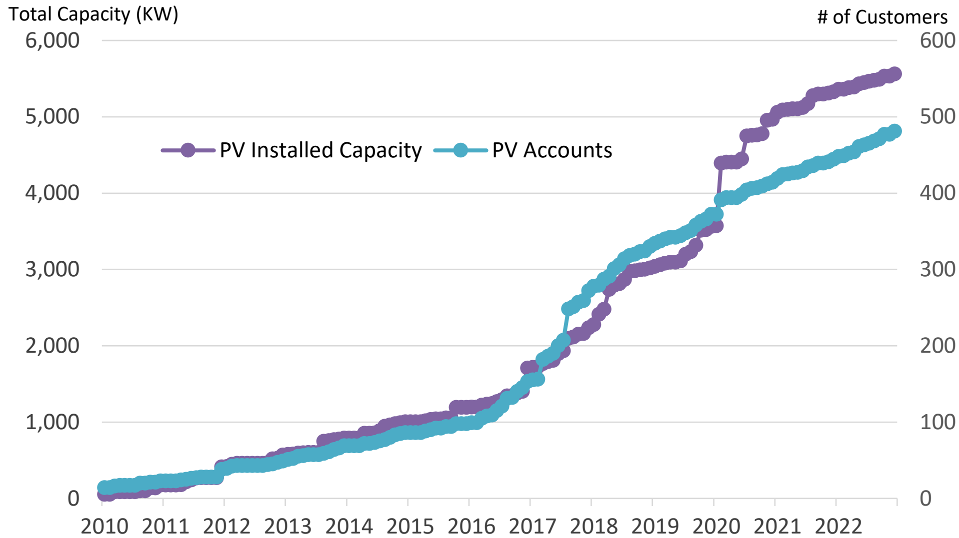
Adjustments for New Technologies

After residential and commercial customer 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 significant growth in the number and size of PV systems installed 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 continue to drive future adoption. Figure 1-20 shows the recent trends in PV adoption. By the end of 2022, BED had 481 net-metering customers, with a total solar capacity of 5.56 MWs and an annual reduction in sales of 6,169 MWhs (1.9% of total BED sales).

Figure 1-20: 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 1,110 residential customers (6.3% penetration) and 170 commercial customers (4.1% 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 4.5 kW for residential systems and 43.2 kW for commercial systems, which is the average system size for all systems installed through 2022. 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 1-4 shows the PV capacity forecast and expected annual generation impacts. By 2042, installed solar capacity within BED territory is expected to reach 12.4 MWs, providing approximately 15,404 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 group net-metering system.

Table 1-4: Solar PV Forecast

	2023	2028	2032	2038	2042
Residential PV Customers	413	616	778	982	1,110
% of Total Residential Customers	2.3%	3.3%	4.1%	5.1%	5.6%
Commercial PV Customers	90	118	137	159	170
% of Total Commercial Customers	2.3%	2.9%	3.3%	3.8%	4.0%
Installed Capacity (MW)	5.8	7.9	9.5	11.4	12.4
Generation MWhs	7,175	9,839	11,787	14,106	15,404

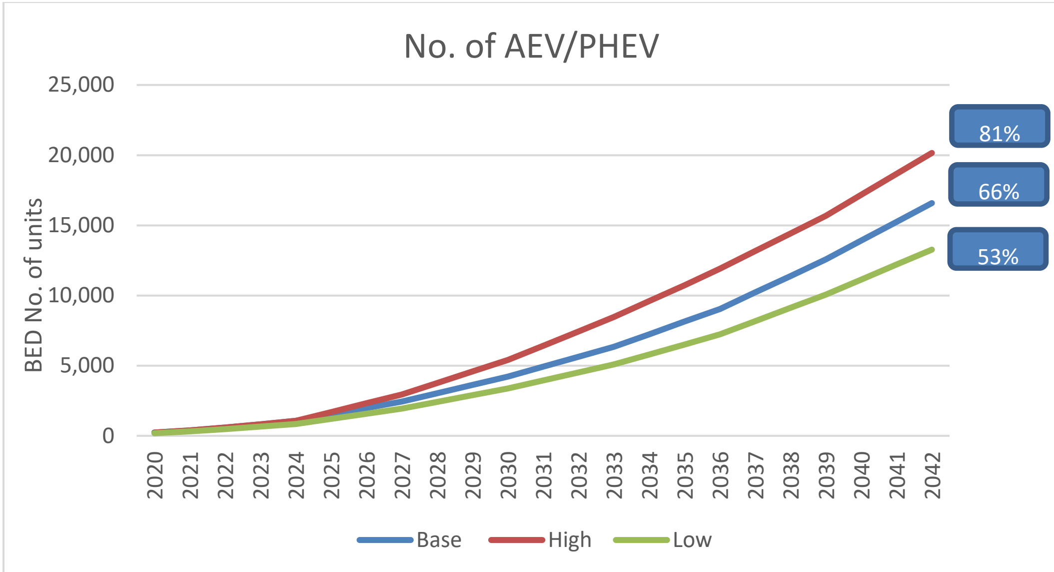
Electric Vehicle Forecast

As done in its 2020 IRP, BED integrated into its long-term planning models explicit forecasts of EV adoption in Burlington. In 2022, there were approximately 575 all-electric vehicles ("AEVs") and plug-in hybrid EVs ("PHEVs") registered in Burlington. With 25,500 total registered light-duty vehicles, AEV/PHEVs account for less than 2.5% of all vehicles on the road in Burlington. While AEV/PHEVs currently represent a small percentage of the registered vehicles, AEV/PHEV adoption is forecasted to continue to increase over the planning period because:

- AEV/PHEV technology is improving;
- Operating an AEV costs less than a traditional vehicle;
- Range anxiety has been declining as the number of EV chargers has expanded and vehicle ranges increase; and,
- Continued financial support in the form of state/federal/utility incentives have significantly improved the upfront cost competitiveness of AEVs/PHEVs.

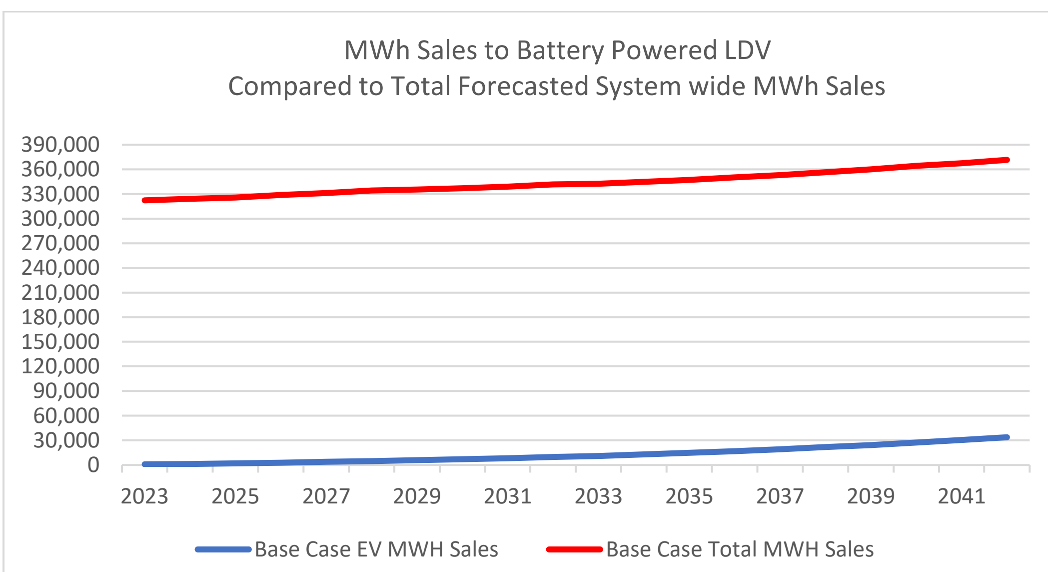
The AEV/PHEV vehicle forecast was developed internally by BED staff. It was based primarily on BED's historical Tier III adoption rates (from CY2017 - CY2022), DriveElectric VT's statewide forecasts for VELCO, and the Vermont Agency of Natural Resources' rules restricting the sale of new fossil-fuel driven light duty vehicles by 2035. In BED's view, AEV/PHEV saturation is anticipated to increase from 2.5% of total registered vehicles to 66% (or more) under base case assumptions, as shown in Figure 1-21.

Figure 1-21: Projected AEV/PHEV growth in Burlington



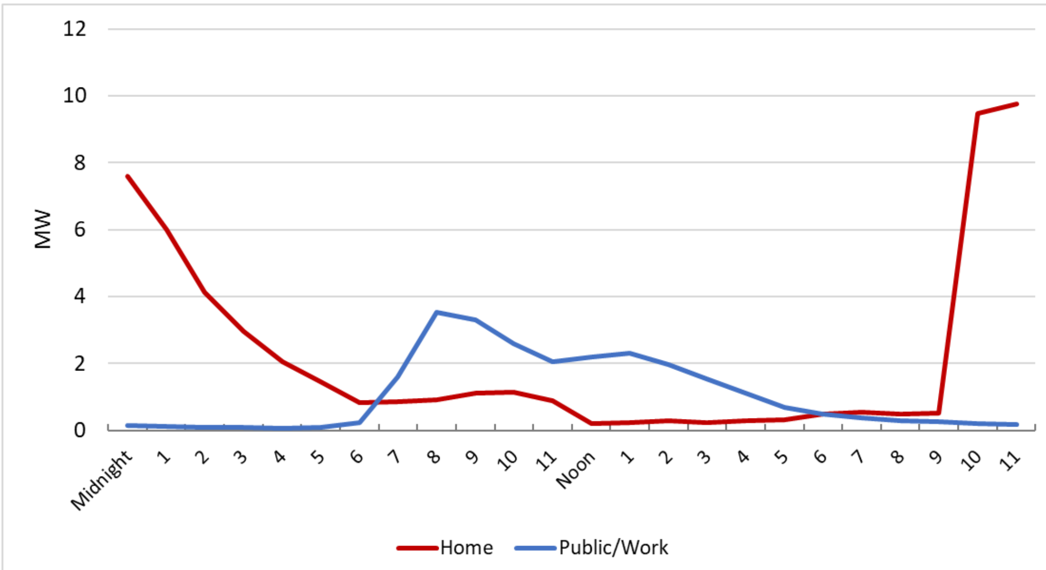
As the number of registered EVs in Burlington increase, so too will MWh sales. As shown in Figure 1-22 below, MWh sales to households who own one more EVs is expected to increase from 800 MWh annually during 2023 to slightly over 33,700 MWhs annually in 2042. Under this scenario, EV-related sales will represent just under 10% of total base case MWh sales. BED also expects additional MWh sales to other types of electric vehicles over the planning period. Such electric sales include sales to non-BED customers using publicly available EV chargers, workplace EV chargers, and electric buses. Together, MWh sales to these other types of EV uses amount to no more than 5,000 MWh annually by 2042 under base case assumptions.

Figure 1-22: Forecast MWh Sales to Battery-Powered Light-Duty Vehicles and Forecast Total MwH Sales



BED expects that the system-wide impact of EVs will be minimal over the planning period under base case assumptions. Our expectation is based on the successful implementation of BED's EV rate credit program, which has been offered since 2017. As of October 2023, 232 households are enrolled in the EV rate credit program and have agreed to charge their vehicles between 10:01 PM and 12:00 noon the next day. Figure 1-23 illustrates the charging profile of a typical household on the EV rate credit program.

Figure 1-23: Typical charging profile of BED EV rate customer



For planning purposes, BED assumed 80% of households participating in BED's Tier III EV rebate program will also sign up for the EV rate credit. As a result, EVs charging at residences will likely have little impact, if any, on system peak demand. BED notes, however, that publicly available and workplace EV chargers will likely contribute to system peaks over time, as these devices are not currently under a rate credit program or controlled externally by BED. The overall impact of public and workplace EV chargers, however, is anticipated to be somewhat muted in the short term as there are relatively few such EV charging devices in operation currently.[12] As the deployment of such devices increases, however, BED will adjust its operational procedures in the future as necessary to minimize system impacts.

Heat Pump Forecast

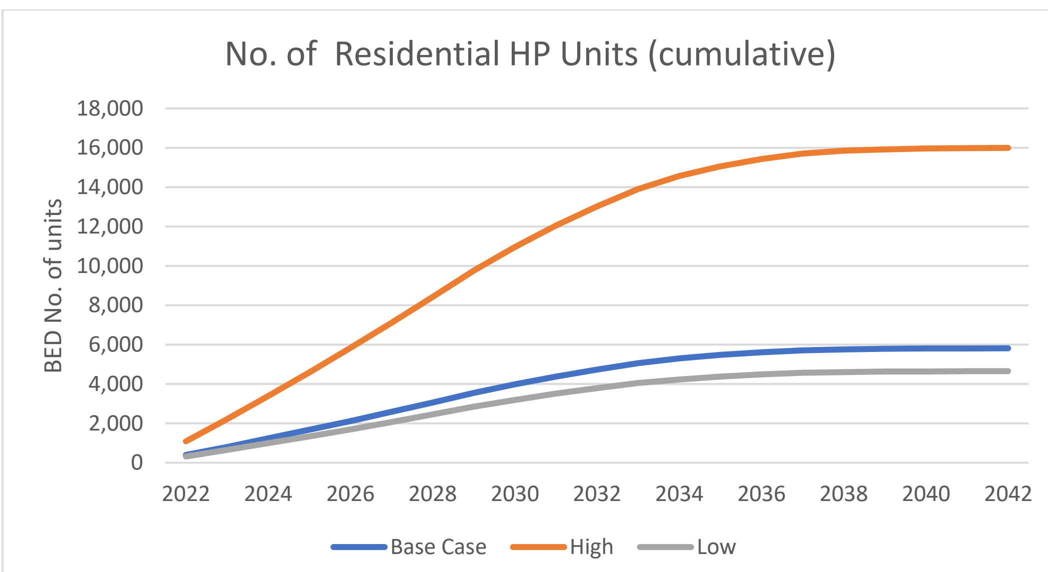
Because heating buildings is the single largest source of greenhouse gas emissions in the City, BED has prioritized efforts (and financial resources) to encourage customers to transition to renewably sourced heating solutions as quickly as possible. BED commenced offering

[12] As of October 2022, BED owns 18 public level 2 chargers with 33 ports and 1 direct current fast charger with 2 ports.

significant incentives for a range of advanced heat pump products[13] in 2017, the first year of the Vermont renewable energy standard. Initially, heat pump adoption was slow. That changed in 2020 when the COVID pandemic was at its height. The pace of heat pump installation increased significantly in 2020 and has continued through mid-2023 for a variety of reasons: federal COVID relief payments to households, increased BED incentives, increased awareness about the importance of indoor air quality, improving heat pump technology, and increased public outreach by installation contractors, Efficiency Vermont, and other distribution utilities.

Because of this strategic priority, BED integrated into its long-term planning models explicit forecasts of heat pump adoption. As of 2022, 838 advanced heat pumps (excluding heat pump water heaters or "HPWH") had been installed with incentives from BED's Tier III programs. The total number of heat pumps deployed in Burlington is estimated to increase to approximately 1,300 by the end of 2023, in line with the high case forecast highlighted in Figure 1-24 below. However, BED does not anticipate the rate of adoption seen over the past 3.5 years will continue indefinitely. Under base case assumptions, we estimate that the number of heat pumps installed in the City will likely increase from 1,300 units to 5,800 units by 2042, meaning that 30% of residential households will rely on advanced heat pumps for at least a portion of their heating needs over time.

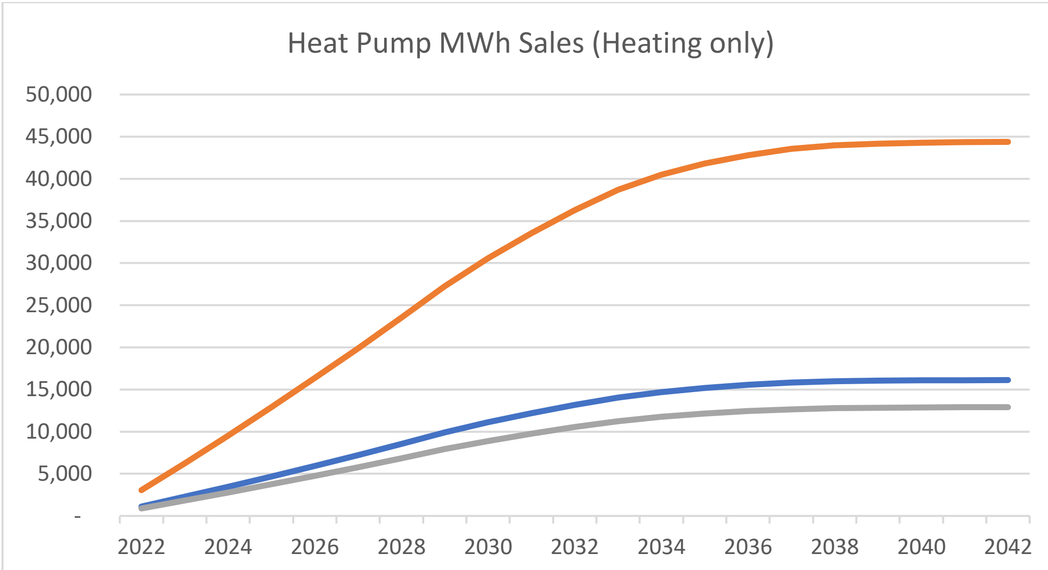
Figure 1-24: Projected Growth in Residential Heat Pumps



[13] Technologies include air-to-water heat pumps, centrally ducted heat pumps, and multi- and single-zoned ductless heat pumps.

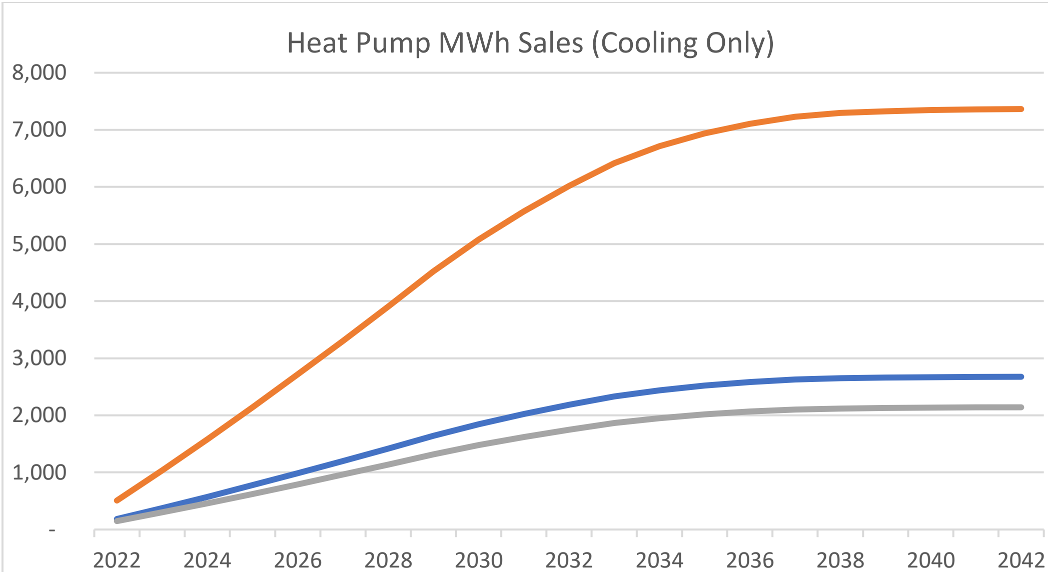
As heat pumps are installed, MWh sales will also increase. As shown in Figure 1-25, heat pump electric sales for heating only are estimated to increase from 1100 MWh to 16,100 MWh by 2042, roughly 5% of base case electric sales.

Figure 1-25: Projected Heat Pump MWh Sales-Heating only



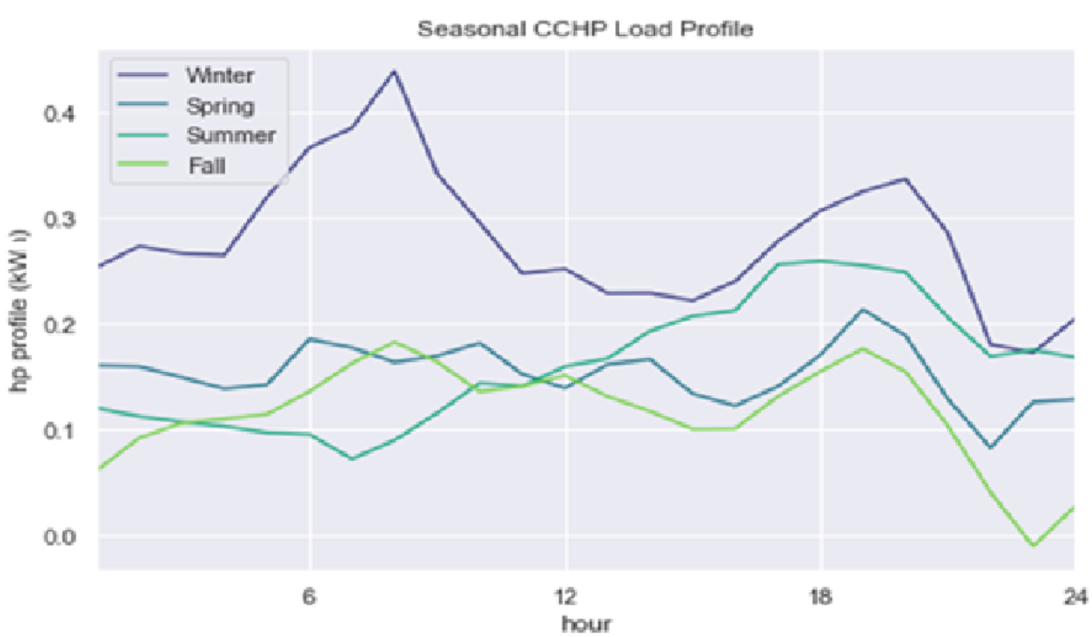
Advanced heat pumps will also be used for cooling new spaces and replacing inefficient room air conditioners. As shown in Figure 1-26, summer cooling–related electric sales will increase from 300 MWh to 2,600 MWh by 2042. It is important to note that the summer cooling sales estimates below consider incremental changes in space cooling consumption. While some customers will replace their inefficient room air conditioners with an advanced heat pump, thus reducing forecasted load, others will use their new heat pump to cool new spaces (and/or move their existing room air conditioner), thus increasing forecasted load. Figure 1-26 represents the net incremental increase in MWh sales of these two household use cases.

Figure 1-26: Projected Heat Pump MWh Sales-Cooling only



The cumulative impact of advanced heat pumps installed in Burlington will increase winter peaks. And while heat pumps are highly efficient space conditioners, especially for cooling, their efficiency decreases as outdoor air temperatures decrease. As Figure 1-27 below illustrates, heat pump demand for power will, on average, spike to 0.4 kW during the colder early morning hours of winter. Meanwhile, summer demand for power tops out at 0.25 kW during the hottest afternoons.

Figure 1-27: Seasonal Cold-Climate Heat Pump Load Profile

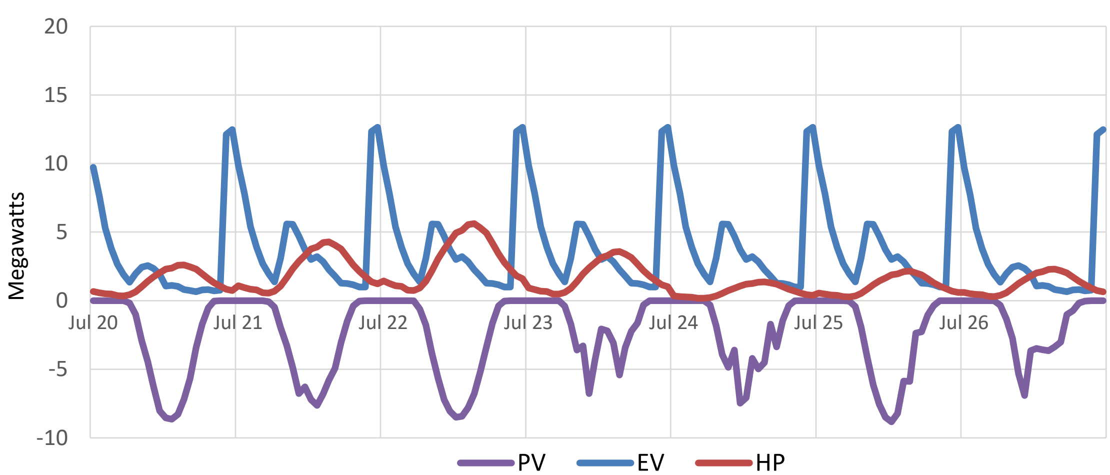


System Load Shape Forecast

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 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, EV, and heat pump adoption. PV reduces system load and demand while EVs and heat pumps add to the baseline system load. Figure 1-28 shows projected PV, EV, and heat pump load impacts for peak week in 2042. While PV growth reduces summer peak demand, expected EV charging (mostly workplace and publicly available charging) and heat pump cooling add load contributing to a positive net impact at peak.

Figure 1-28: Solar PV, EV, and HP hourly impacts during the peak week of July 2042



Over the next 20 years, the base case system energy requirements average 0.8% annual growth. Peak demand increases 0.6% annually over this period. In comparison, from 2012 to 2022, system energy use has averaged a 0.7% decline while peak demand increased 0.1% on average.

Table 1-5 shows the energy and demand forecast after accounting for the effects of future energy efficiency and the PV, EV, and heat pump impacts. Over the next 20 years, the base case system energy requirements average 0.8% annual growth. Peak demand increases 0.6%

annually over this period. In comparison, from 2012 to 2022, system energy use has averaged a 0.7% decline while peak demand increased 0.1% on average.

Table 1-5: Energy & Peak Base Case Forecast

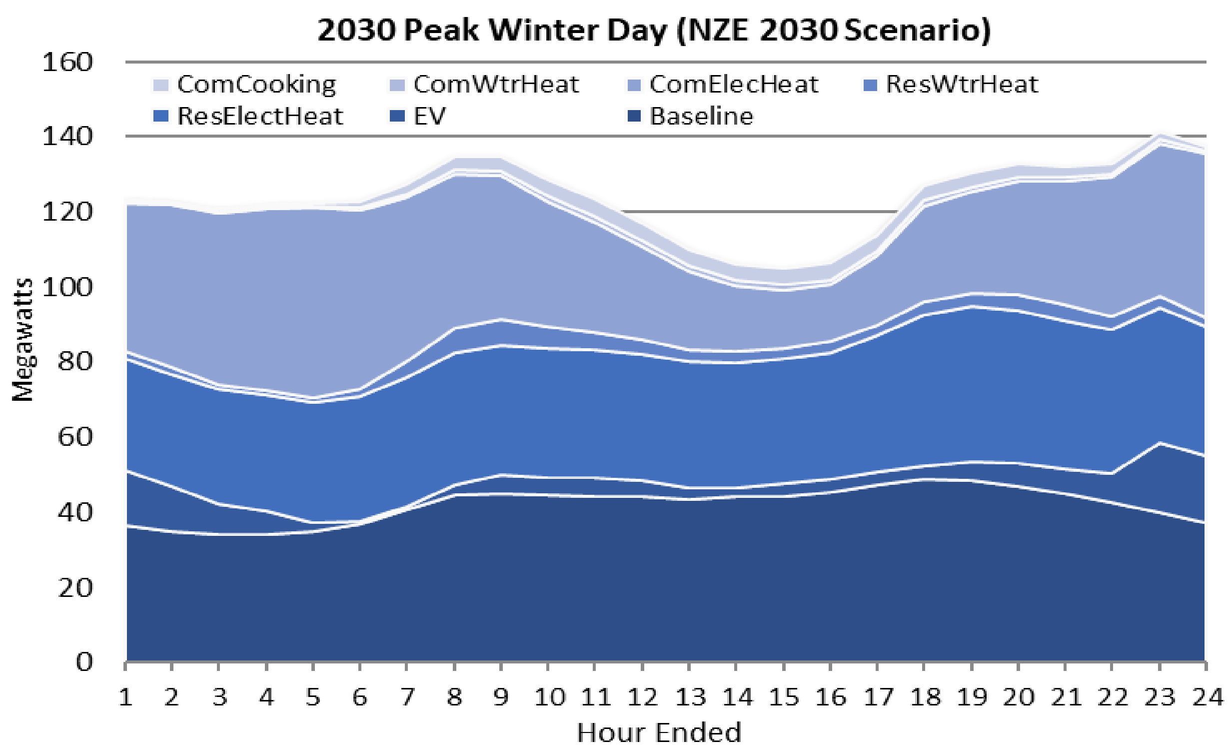
Year	Energy (MWh)	% Chg.	Summer Peak (MW)	% Chg.	Winter Peak (MW)	% Chg.
2012	350,753		63.6		50.9	
2013	349,150	-0.5%	67.2	5.7%	53.1	4.3%
2014	348,338	-0.2%	64.1	-4.6%	53.5	0.8%
2015	350,950	0.7%	64.7	0.9%	53.0	-0.9%
2016	347,309	-1.0%	65.2	0.8%	50.5	-4.7%
2017	338,936	-2.4%	61.7	-5.4%	49.7	-1.6%
2018	341,204	0.7%	67.3	9.1%	50.3	1.2%
2019	329,695	-3.4%	63.1	-6.2%	51.3	2.0%
2020	316,941	-3.9%	59.1	-6.3%	47.6	-7.2%
2021	324,754	2.5%	65.1	10.2%	47.1	-1.1%
2022	327,660	0.9%	63.3	-2.8%	50.2	6.6%
2023	322,301	-1.6%	61.9	-2.2%	51.5	2.6%
2024	324,222	0.6%	62.4	0.8%	52.1	1.2%
2025	325,867	0.5%	62.7	0.5%	52.7	1.2%
2026	328,816	0.9%	63.2	0.8%	53.5	1.5%
2027	331,134	0.7%	63.6	0.6%	54.1	1.1%
2028	334,092	0.9%	64.2	0.9%	54.9	1.5%
2029	335,438	0.4%	64.7	0.8%	55.4	0.9%
2030	337,064	0.5%	65.1	0.6%	56.0	1.1%
2031	338,898	0.5%	65.4	0.5%	56.5	0.9%
2032	341,543	0.8%	65.8	0.6%	56.9	0.7%
2033	342,644	0.3%	66.1	0.5%	57.3	0.7%
2034	344,701	0.6%	66.3	0.3%	57.6	0.5%
2035	346,979	0.7%	66.9	0.9%	57.8	0.3%
2036	350,364	1.0%	67.3	0.6%	58.1	0.5%
2037	352,962	0.7%	67.5	0.3%	58.3	0.3%
2038	356,410	1.0%	67.9	0.6%	58.5	0.3%
2039	359,869	1.0%	68.4	0.7%	58.7	0.3%
2040	364,415	1.3%	68.8	0.6%	58.8	0.2%
2041	367,528	0.9%	69.5	1.0%	59.5	1.2%
2042	371,573	1.1%	69.9	0.6%	61.2	2.9%
‘12-‘22		-0.7%		0.1%		-0.1%
‘23-‘42		0.8%		0.6%		0.9%

Alternative Forecast Scenarios

BED considered three scenarios—low, base, and high—to assess the impacts of a range of load forecasts. This range is highly dependent on the level of EV and heat pump adoption, which result in increased loads, and PV installations, which reduce spring and summer loads. Table 9, below, highlights the results of these different scenarios. The results show that the differences between base and high case energy and peak demand forecasts in 2042 are *not immaterial*. The high case energy estimate is 39,223 MWh or approximately 12% greater than the base case energy estimate and the high case peak demand estimate is 9.5 MW or roughly 14% greater. However, the high case estimates of energy load (410.76 GWh) and peak demand (79.4 MW) in 2042 do not present significant challenges to BED. Renewable energy resources can be procured over time to serve the estimated loads, as further discussed in the Generation and Supply Alternatives chapter. Similarly, BED's electric grid can be bolstered to reliably meet higher peak demands, as we discuss in the Transmission and Distribution chapter.

What this demand forecast does not include is a Net Zero Energy ("NZE") 2030 or NZE 2040 impact assessment, which we included in the 2020 IRP. BED intentionally omitted the impacts of these hypothetical states from the IRP because reaching NZE would necessitate a complete transformation of the City's commercial heating sector. To illustrate this, Figure 1-29 below shows our previous Peak winter day assessment in 2030 under the NZE 2030 roadmap that was included in our 2020 IRP. The top three lines of the graph illustrate the potential impact of commercial space heating, commercial hot water, and commercial cooking on peak demand.

Figure 1-29: 2030 Peak Winter Day (NZE 2030 Scenario)



However, the pace of commercial sector energy transformation is not currently fast enough to warrant inclusion in this IRP as it is unlikely to occur within the 20-year planning period.

For the 2023 IRP, we replaced the above NZE 2030 Winter peak day forecast with Figures 1-30 and Figures 1-31 showing peak winter demand under the high case scenario for January, 2030 and January, 2042.

Figure 1-30: Peak Winter Day (1/23/30) - Base Case 2023 Forecast

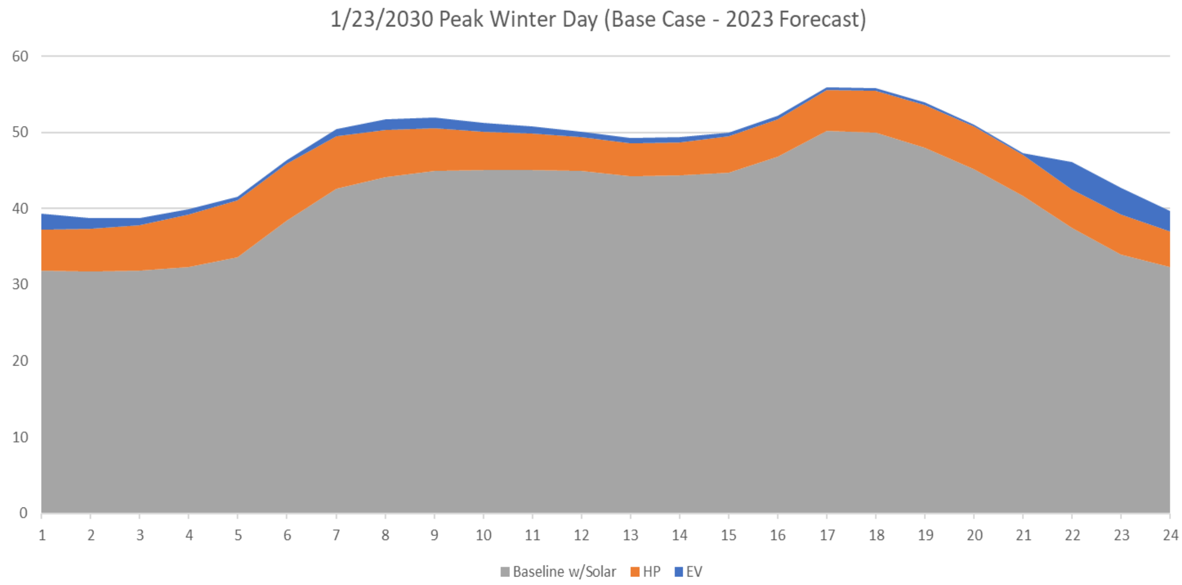
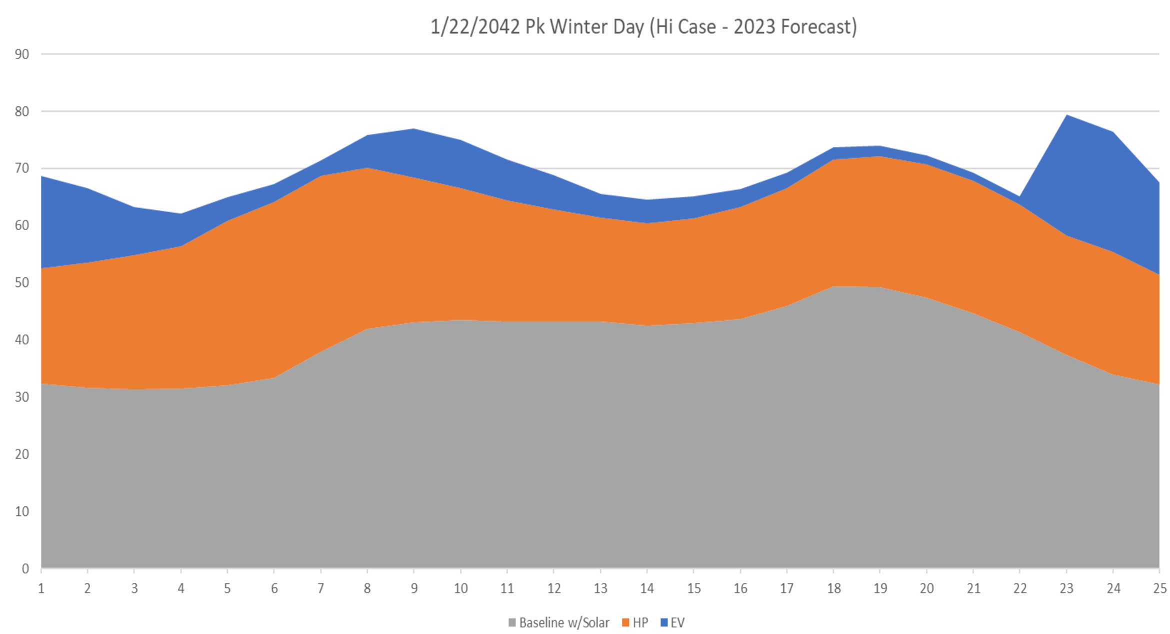


Figure 1-31: Peak Winter Day (1/22/42) - High Case Forecast



As the charts above demonstrate, the high case scenario peaks at 79.4MWs in January 2042 compared to 140MW under the previous NZE2030 scenario where all commercial customers would have relied on beneficial electrification for their thermal needs and all vehicles registered in Burlington are electric.

Although this IRP differs from the 2020 IRP, it was still necessary to model the impacts of heat pump adoption on our resource needs. With a strong increase in cold climate heat pump adoption even under the more modest 2023 high case scenario, it is important to point out that peak demand shifts from the summer months to winter months. By 2030, the aggressive NZE all-commercial space electrification scenario results in a peak demand (140 MW) that is 76% greater than the base case peak demand forecast (79.4 MW). Figure 1-32 and Figure 1-33 compare the hourly load shapes for the years 2030 and 2039 for each of the scenarios.

Figure 1-32: Scenario Load Comparison in 2030

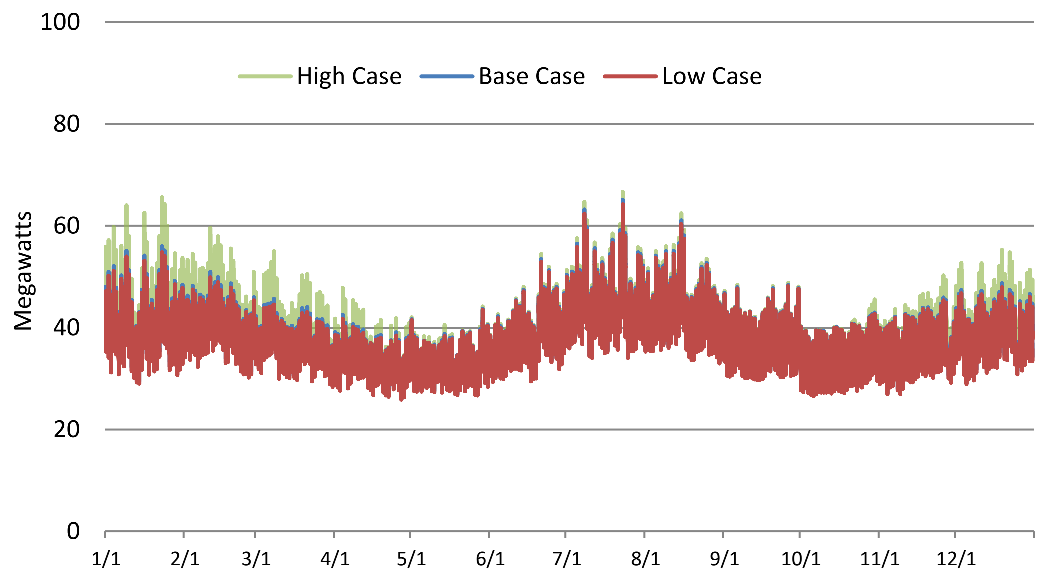


Figure 1-33: Scenario Load Comparison in 2042

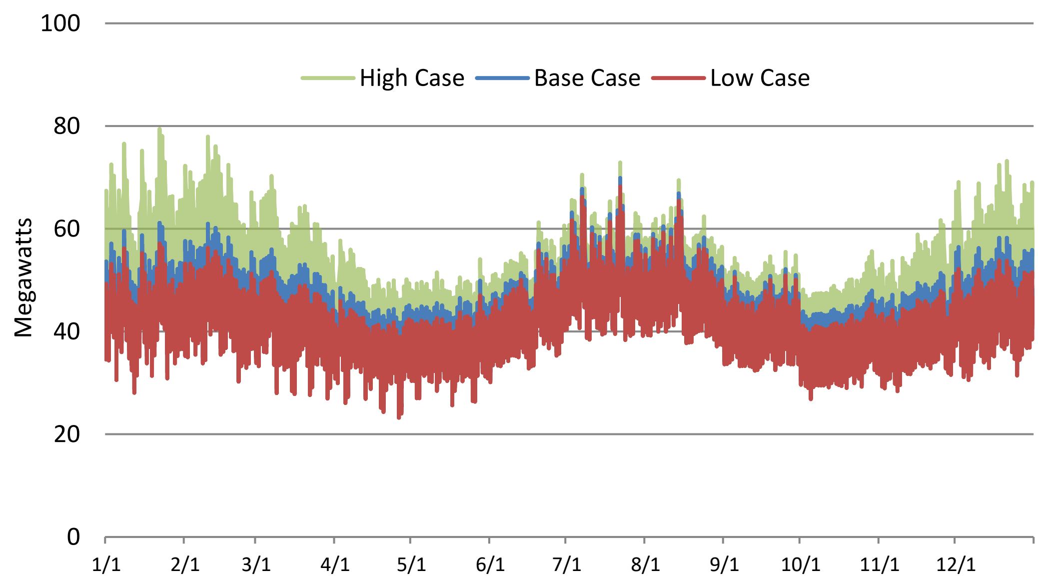


Figure 1-34 provides a look at the peak day load shape in 2042 for the high case scenario. The load shape is characterized by dual peak periods occurring in the morning around 9:00 am, and in the evening at 11:00 pm. The increase in demand during the morning period is caused by the need for heating and domestic hot water. The increase in demand during the evening period is caused by EV charging under BED's EV rate credit program.

Figure 1-34: 2042 Peak Day (1/23) assuming the High Case Scenario

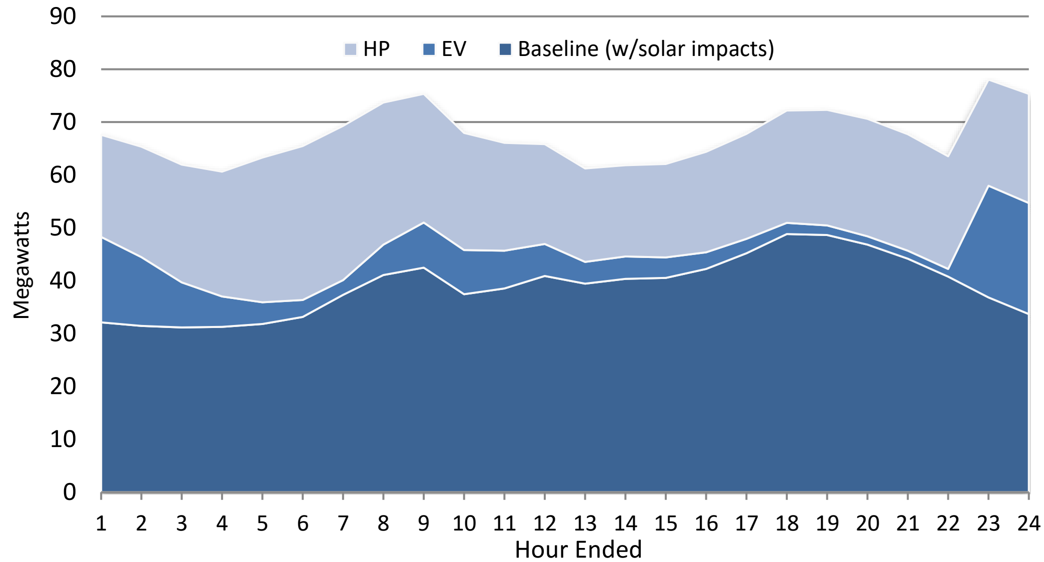


Table 1-6 summarizes the peak and energy forecasts for the various scenarios.

Table 1-6: System Peak & Energy Forecast Scenarios

Year	Low Case Energy (GWh)	Base Case Energy (GWh)	High Case Energy (GWh)	Low Case Peak (MW)	Base Case Peak (MW)	High Case Peak (MW)
2023	321.94	322.30	324.45	61.8	61.9	62.1
2024	323.00	324.22	328.10	62.2	62.4	62.7
2025	324.18	325.87	332.47	62.4	62.7	63.2
2026	326.64	328.82	338.21	62.7	63.2	63.9
2027	328.47	331.13	343.36	63.1	63.6	64.5
2028	330.88	334.09	349.50	63.5	64.2	65.3
2029	331.66	335.44	354.06	64.0	64.7	66.1
2030	332.77	337.06	358.66	64.2	65.1	66.7
2031	334.05	338.90	363.53	64.5	65.4	67.2
2032	336.16	341.54	369.03	64.7	65.8	68.6
2033	336.75	342.64	372.80	64.9	66.1	69.9
2034	338.25	344.70	376.86	65.1	66.3	70.9
2035	340.01	346.98	380.84	65.6	66.9	71.6
2036	342.89	350.36	385.84	66.0	67.3	72.3
2037	344.86	352.96	389.35	66.1	67.5	73.5
2038	347.72	356.41	393.47	66.5	67.9	74.4
2039	350.60	359.87	397.48	66.9	68.4	75.0
2040	354.46	364.42	402.58	67.3	68.8	76.0
2041	356.88	367.53	406.21	67.9	69.5	77.5

2042	360.24	371.57	410.76	68.2	69.9	79.4
23-42	**0.6%**	**0.8%**	**1.2%**	**0.5%**	**0.6%**	**1.3%**

Figure 1-35 and Figure 1-36 compare energy and demand for the high and low scenario forecasts against the base case.

Figure 1-35: System Energy Forecast Scenarios

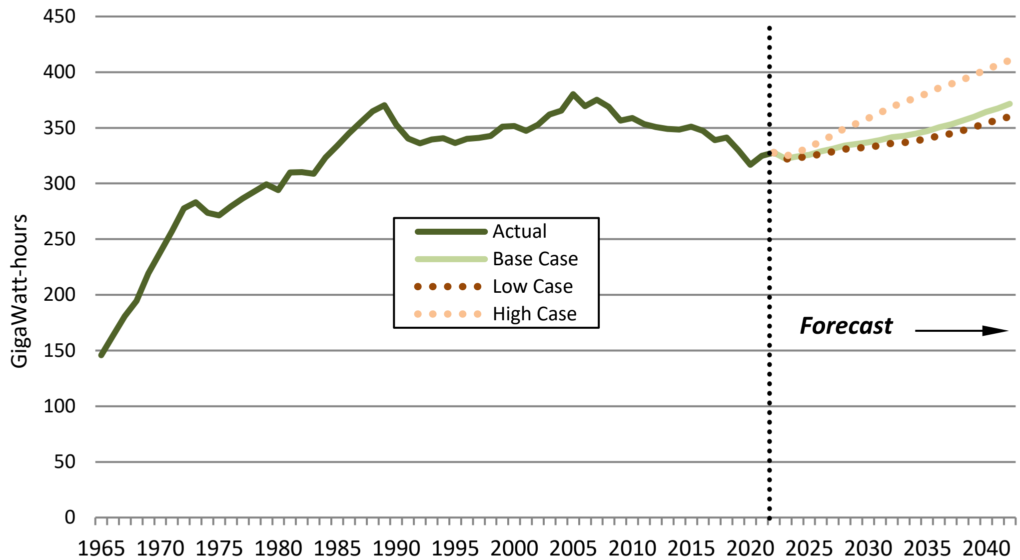
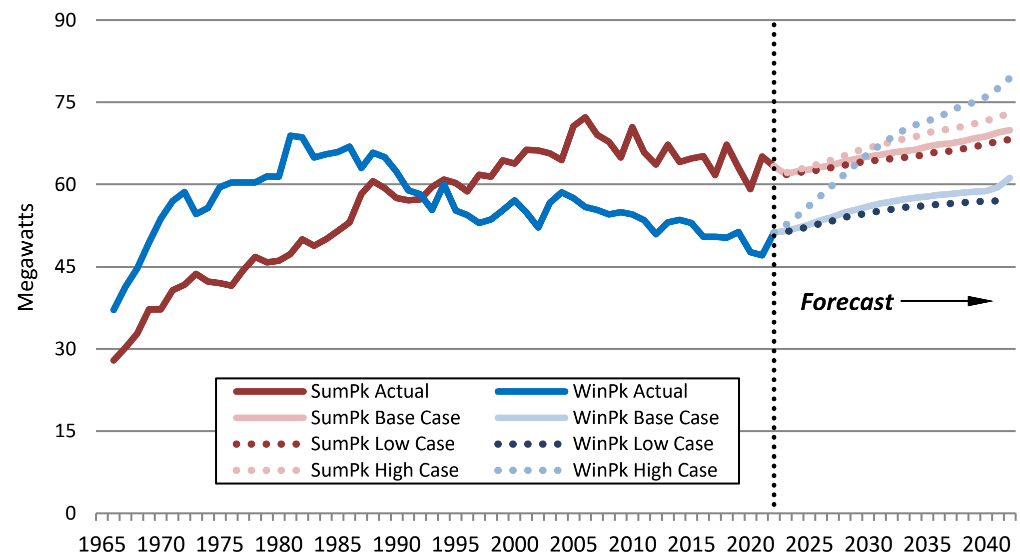


Figure 1-36: System Peak Demand Scenarios



2. Generation & Supply Alternatives

Consistent with 30 V.S.A. § 218c, BED evaluated its future energy and capacity needs and compared them to its current resources and planned resource additions. Future energy and capacity needs are based on the 20-year load forecast, which reflects various scenarios including the potential impacts of strategic electrification initiatives, distributed generation resources, and electric energy efficiency. However, this IRP rests on a final forecast that reflects our assessment of the most likely scenario for our future energy requirements and annual capacity obligations (i.e., demand at ISO-NE peak hour plus reserves).

In this chapter, BED provides an overview of its existing energy and capacity resources, as well as a description of the renewable energy credits ("RECs") generated from such resources. We then summarize BED's processes for evaluating future supply options. Lastly, this chapter includes an analysis of the potential resources available to BED to meet its future obligations.

Current Resources

Over the 2023-2042 IRP planning period, BED's existing resource mix is comprised of owned and contracted resources. Table 2-1 provides an overview of the basic characteristics of BED's existing resources and describes the growth and expiration of BED's contracted resources during the IRP period.

Table 2-1: 2023-2042 Power Supply Resources

Resource	Description	Fuel	Location	Expiration
BED Owned Resources				
McNeil	Dispatchable unit	Wood	VT Node 474	Owned
BED GT	Peaking unit	Oil	VT Node 363	Owned
Winooski One	Run of river hydro	Hydro	VT Node 622	Owned
Airport Solar	Fixed array rooftop solar	Solar	Internal to BED system	Owned
BED (585 Pine St) Solar	Fixed array rooftop solar	Solar	Internal to BED system	Owned
BED Contracted Resources				

Resource	Description	Fuel	Location	Expiration
NYPA	Preference power	Hydro	Roseton Interface 4011	Niagara: 2025 St. Lawrence: 2032
Hydro Quebec	7x16 Firm energy only	HQ system mix	Highgate Interface 4013 (via market bilateral)	2035 and 2038
VT Wind	Intermittent	Wind	VT Node 12530	2026
Georgia Mountain Community Wind	Intermittent	Wind	VT Node 35555	2037
Great River Hydro	Small hydro portfolio (7x16)	Hydro	Vermont Node 335	2024
Hancock Wind	Intermittent	Wind	Contract delivers to Vermont Zone 4003	2027
Market	ISO-NE or bilateral energy	System mix	Various NE Nodes	No market energy contracts currently
Solar	Long-term contract - Intermittent	Solar	Internal to BED system	2032 and 2043
Solar	Net metering - Intermittent	Solar	Internal to BED system	N/A

- **McNeil Station:** BED is a 50% owner of the McNeil Station, which entitles BED to 25 MW of nameplate capacity (although peak capability is higher). The plant is projected to operate approximately 60% of the total available annual hours for the entire IRP period. The selective catalytic reduction unit installed in 2008 has allowed for the reduction of NO_x emissions as well as the ability to improve the economics of plant operations through the sale of Connecticut Class I RECs. As discussed below, the value of McNeil's RECs is changing, but will continue to benefit the economics of the plant. BED bids the unit partially based on variable costs, recognizing that REC revenues will be received in addition to energy revenues.
- **Burlington Gas Turbine ("GT")**: BED is the sole owner of this oil-fired peaking unit with a 25.5 MW nameplate rating. BED's GT is assumed to be available to provide peaking energy, capacity, and reserves.
- **Winooski One:** BED took ownership of the Winooski One facility effective September 1, 2014. This is a Low Impact Hydropower Institute ("LIHI")–certified hydro facility electrically connected to BED's distribution system. LIHI's voluntary certification program recognizes hydropower dams that are minimizing their environmental impacts

and enables such low-impact projects to access certain REC markets. Winooski One currently produces Massachusetts Class II (non-waste) RECs in addition to the energy and capacity normally associated with such a unit. The unit is qualified in the ISO-NE Forward Capacity Market ("FCM") (as an intermittent resource) and operates at an approximate 50% annual capacity factor.

- **Airport Solar:** on January 26, 2015, BED commissioned its 576.5 kW DC (499 kW AC) rooftop solar facility on the Patrick Leahy Burlington International Airport parking garage. BED has a 20-year lease for this rooftop space. With this project, the airport has reduced the need to import energy from outside sources.
- **BED Rooftop Solar:** In October 2015, BED commissioned a 124 kW DC (107 kW AC) solar array on the rooftop of BED's Pine Street headquarters. This new solar array is a BED-owned asset and reduces the need to buy energy from outside sources.
- **NYPA**: BED receives approximately 2.616 MW of New York Power Authority ("NYPA") power through two separate contracts. The contracts, Niagara, and St. Lawrence, expire in 2025 and 2032, respectively. Energy under these contracts is favorably priced but NY Independent System Operator ("NYISO") ancillary charges are incurred to deliver the energy to New England.
- **Hydro Quebec**: Along with many of the other Vermont utilities, in 2010 BED executed a contract for firm energy deliveries from Hydro Quebec. For BED, this contract started in November 2015 at 5 MW and increased to 9 MW in November 2020. The current contract expires in 2038. Energy deliveries are by market transfer and are delivered during the "7x16" market period (i.e., hour-ending 8 [am] to hour-ending 23 [11pm], all days including holidays). This contract does not provide any corresponding market capacity.
- **VEPP Inc.**: In accordance with 30 V.S.A. § 8009(g), as of November 2012, BED must take an assignment of Ryegate energy <u>only</u> if BED fails to meet its statutory baseload biomass requirement by generating at least one-third of its annual energy needs with McNeil

biomass generation.[14,15,16] BED has met this requirement every year with McNeil generation and plans to continue to do so.

- **Vermont Wind:** BED receives 16 MW of the 40 MW nameplate capacity of Sheffield Wind Farm in Sheffield, VT. This contract includes the energy, capacity, RECs, and ancillary products from the facility throughout the lifetime of the 10-year contract and five-year extension, which will expire in 2026.
- **Georgia Mountain Community Wind**: In 2012, BED entered into a 25-year contract for 100% of the output from the 10 MW Georgia Mountain Community Wind facility. The contract includes energy, capacity, RECs, and any other credits the project may produce.
- **Hancock Wind**: In 2016, BED began receiving energy under a 10-year contract where BED is entitled to 13.5 MW of energy and capacity from the output of the Hancock Wind facility in Hancock County, Maine. The contract includes energy, capacity, RECs, and any other credits the project may produce. The facility does not generally produce capacity credits but has done so during the two Pay-for-Performance events.
- **Great River Hydro:** BED has two- and five-year agreements (covering the period 2018-2024) with Great River Hydro for 7.5 MW of output from a portfolio of hydro resources located on the Connecticut River. The contract is unit-contingent based on the combined output of the three facilities specified and includes the renewable attributes associated with the actual output delivered to BED.
- **Bilateral Market Contracts:** For any energy that BED needs beyond what is supplied by its owned and contracted resources, BED has a long-standing strategy of hedging its exposure to spot market price variability. Based on its energy needs, BED may purchase one-third of its remaining energy requirements for the future 7- to 15-month period at the end of each calendar quarter, if necessary. Such purchases effectively hedge most of BED's energy requirements for the following 12-month period. This strategy has been approved by BED's Board of Electric Commissioners and the Burlington City Council

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[14] 30 V.S.A. § 8009(a)(2) "Baseload renewable power portfolio requirement" means an annual average of 175,000 MWh of baseload renewable power from an in-state woody biomass plant that was commissioned prior to September 30, 2009, has a nominal capacity of 20.5 MW, and was in service as of January 1, 2011.

[15] 30 V.S.A. § 8009(b) Notwithstanding subsection 8004(a) and subdivision 8005(c)(1) of this title, commencing November 1, 2012, each Vermont retail electricity provider shall purchase the provider's pro rata share of the baseload renewable power portfolio requirement, which shall be based on the total Vermont retail kWh sales of all such providers for the previous calendar year. The obligation created by this subsection shall cease on November 1, 2032 unless terminated earlier pursuant to subsection (k) of this section.

[16] 30 V.S.A § 8009(g) A retail electricity provider shall be exempt from the requirements of this section if, and for so long as, one-third of the electricity supplied by the provider to its customers is from a plant that produces electricity from woody biomass.

Transportation, Energy & Utilities Committee. Additionally, BED's strategy allows for additional purchases if spot energy market prices are at a level that allows some measure of rate stability. Currently, BED does not have significant annual market exposure. BED is somewhat long on energy through 2025; beyond that BED will likely enter into additional power purchase agreements to fill any significant energy shortfall. BED is not expecting to rely on the structured purchasing policy in the near future.

- **Solar (Contracted):** BED has obtained the rights to the output of relatively small PV arrays located on several of the City's schools as well as on some non-profit housing properties. These projects are under long-term purchase power agreements that expire in 2032. BED also has the rights to the output of the 2.5 MW South Forty Solar array, which expires in 2043.
- **Solar (Net-Metered):** Burlington customers can install net-metered projects (with solar being the predominant technology in BED's territory). Net-metered projects reduce Burlington's load and lower BED's capacity obligation. By the end of 2022, BED had 481 net-metering customers, with a total solar capacity of 5.56 MWs and an annual reduction in sales of 6,169 MWhs (0.8% of total BED sales).
- **Vermont Standard Offer Contracts:** Since January 1, 2017, pursuant to PUC Order of January 13, 2017, in Case 8863, BED has been exempted from purchasing Standard Offer energy. BED has continued to meet the requirements for this exemption and expects to continue to do so for the IRP period.

Renewable Energy Credits

As shown in Table 2-2, BED obtains RECs from a variety of generation resources. BED generally sells its high-value RECs to generate additional revenue. RECs generated from BED's resources could also be retired against load in the future if such retirements help BED to achieve renewable energy requirements at a lower cost than is possible by purchasing replacement RECs.

Table 2-2: BED REC Resources

Resource	Description	Fuel	REC Classification	Status
BED Owned Resources				
McNeil	Dispatchable Biomass	Wood	Connecticut Class 1[17]	Active Sales
Winooski One	Run of River hydro	Hydro	Massachusetts Class 2 (non-waste)	Active Sales
Airport Solar	Fixed array rooftop solar	Solar	Massachusetts Class 1	Active Sales
BED (585 Pine St) Solar	Fixed array rooftop solar	Solar	Vermont Tier 2, Massachusetts Class 1	Active Sales
BED Contracted Resources				
VT Wind	Intermittent wind	Wind	Tri-Qualified (Connecticut, Massachusetts, and Rhode Island Class 1)	Active Sales
Georgia Mountain Community Wind	Intermittent wind	Wind	Tri-Qualified (Connecticut, Massachusetts, and Rhode Island Class 1)	Active Sales
In-City Solar (8 sites)	Long-term contract (PPA)	Solar	Massachusetts Class 1 (5 of 8 are currently registered); two are also registered as Vermont Tier 2	Active Sales
Hancock Wind	Intermittent Wind	Wind	Tri-Qualified (Connecticut, Massachusetts, and Rhode Island Class 1)	Active Sales
Great River Hydro	Large Hydro	Hydro	Vermont Tier 1	Used for VT Tier 1 Compliance

[17] As discussed in the McNeil REC Status subsection, the value and qualification of McNeil's RECs is changing.

Resource	Description	Fuel	REC Classification	Status
Hydro-Québec	Large Hydro	Hydro	Vermont Tier 1	Used for VT Tier 1 Compliance
NYPA	Large Hydro	Hydro	Vermont Tier 1	Used for VT Tier 1 Compliance

McNeil REC Status

Currently, McNeil creates one CT Class 1-qualifed REC for each MWh it produces. Going forward from August 2025, every other REC McNeil produces will be CT Class 1-qualified.

BED is looking to qualify around 10% of McNeil's RECs for the relatively high value New Hampshire Class 1 market. NH's renewable energy portfolio allows biomass facilities, such as McNeil, to become eligible under its RPS for the incremental generation of electricity relative to a historical baseline resulting from capital improvements. As noted above, BED completed a number of important upgrades at McNeil that allowed BED to qualify McNeil for the CT class 1 REC market. McNeil will retain its Vermont Tier 1 qualification status, and thus have values for Vermont Tier 1 compliance. BED will also continue to maximize the value of all the RECs that it receives.

Gap Analysis

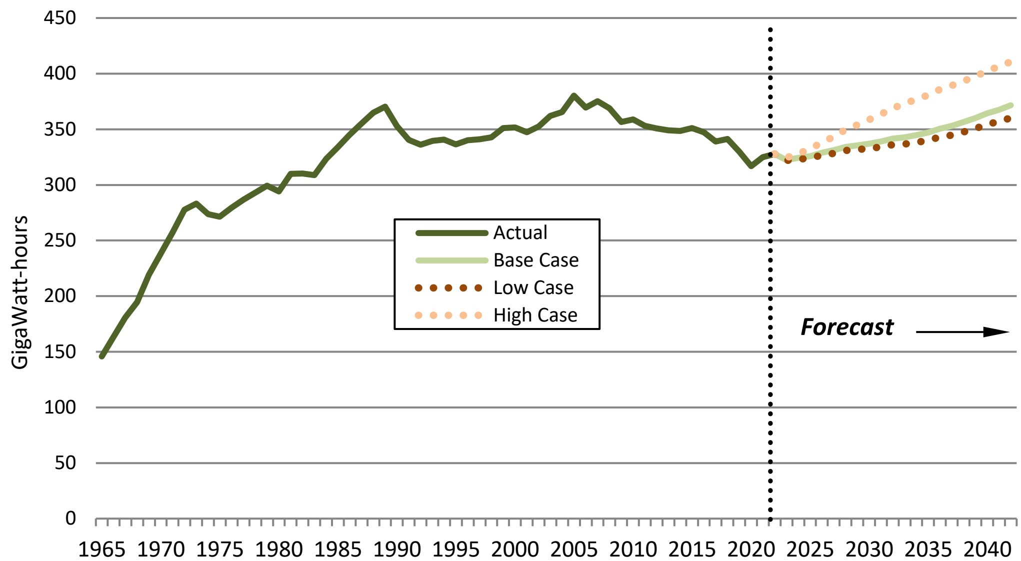
Under the base case load forecast scenario, energy load in the City is expected to increase from 327 GWh to 371 GWh between 2022 and 2042, a growth of around 0.6% annually. The relatively flat load growth is generally a function of aggressive energy efficiency programs, rising building codes/standards and appliance efficiency standards, and flat population growth.

There is, however, the potential for energy loads to increase at a faster pace than the base case scenario. Factors that could drive electric energy loads up include, but are not limited to, a population growth rate that is higher than originally anticipated, a more robust economy that results in job and business creation, and greater acceptance of energy transformation projects than projected or other activities taken by local or State governments that accelerate the pace of strategic electrification. It is likely that the thermal-sector fossil fuel reduction inducements passed in Act 18 of 2022 will lead to increased electrification, although the precise localized impact is not known at this time.

Energy loads could also decrease relative to the base case scenario, at least in the short term. Lower than expected energy demand would likely be due to increased levels of net metered PV installations, economic recession, and/or population migration out of the City and/or Vermont.

Figure 2-1 shows the base case load forecast as described in Chapter 1.

Figure 2-1: System Energy Forecast: 2023-2042



Similar to forecasted energy sales, system peak demand is also expected to remain flat over the short-term planning period. Flat growth is contigent primarily on "normal" weather patterns continuing into the future; meaning, summer temperatures do not vary dramatically from historical trends. Under this base case scenario, BED also assumes that the duration of summer hot spells is not materially different than past experiences.

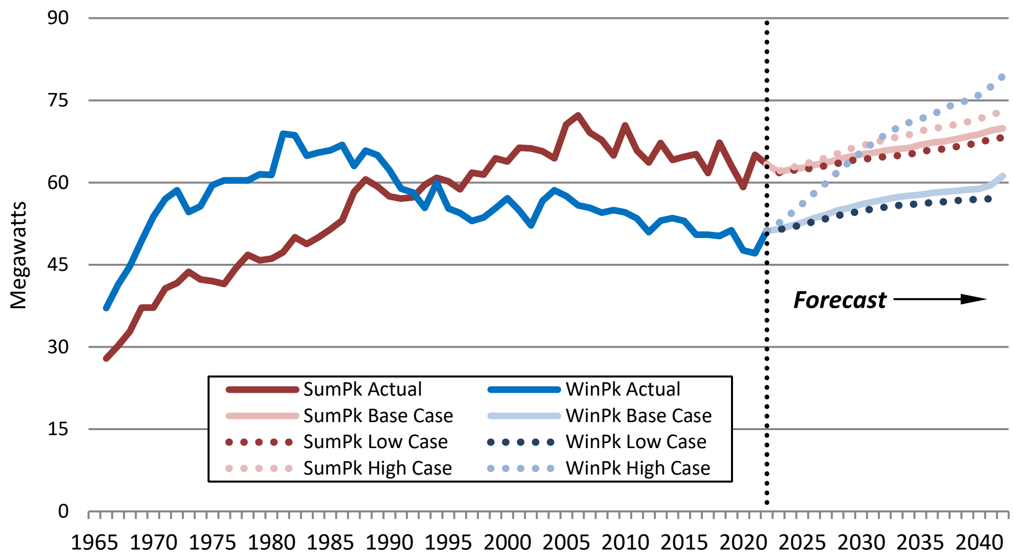
Higher than expected peak demand growth may, however, be driven by a variety of causes. The most likely reason would be hotter than expected summer tempertures. Demand could also rise due to increased population growth, higher employment, and/or business formation levels than anticipated, as well as additional cooling demand in building areas that were not previously air conditioned. Such additional cooling load increases, if they occur, could be a consquence of increased adoption in cold climate heat pumps, which also serve as efficient cooling systems during the summer.

Additionally, winter peak demand could increase relative to base case expectations due to higher than expected market penetration of cold climate heat pumps used for space heating. Since current peak winter demand is considerably lower than summer peak demand, increased use of cold climate heat pumps is not viewed as a potential reliability problem during the winter in the base case scenario, however, as noted in Chapter 7, Burlington's peak may shift to the winter under the NZE scenarios.

Summer peak demand may also decrease in comparison with the base case in the short term at least. Reasons that may lead to lower peak demand include higher penetration of net metered

PV and/or increases in demand resources. Decreases in population growth and economic malaise could also diminish both summer and winter peak demand.

Figure 2-2: System Peak Demand Forecast, 2023-2042

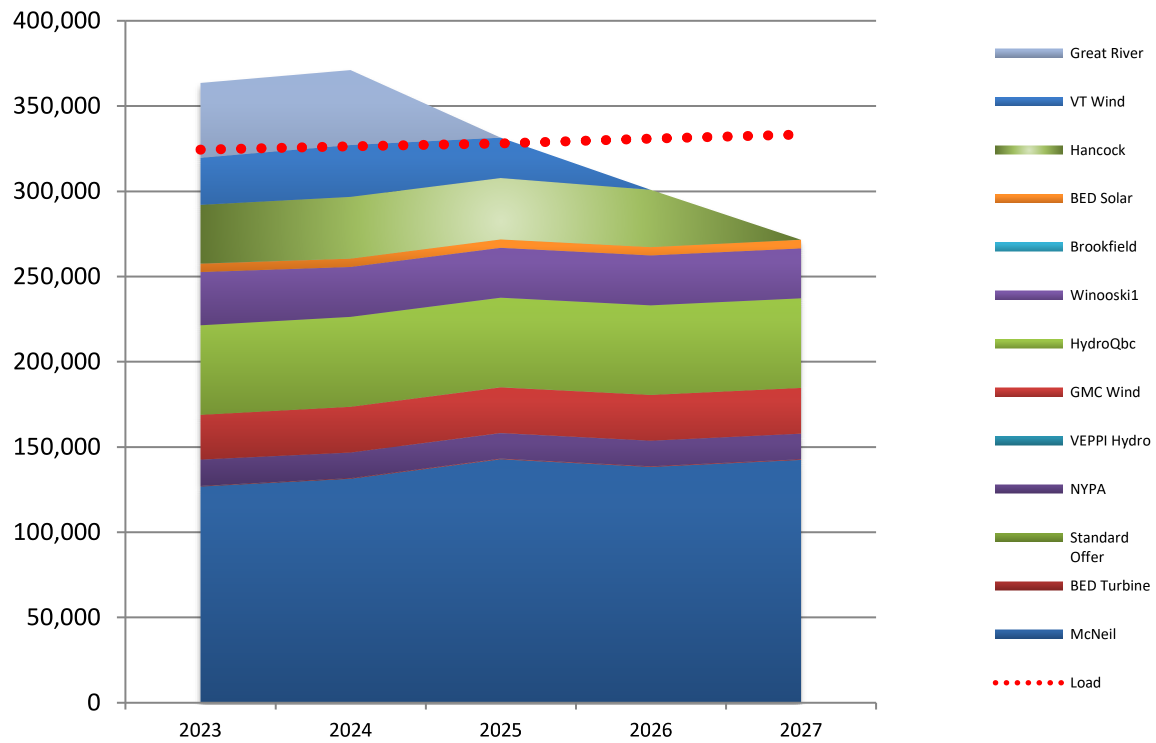


As noted above, customer adoption of energy transformation technologies may impact BED's energy and capacity needs in the future. A faster-than-anticipated rate of adoption of cold climate heat pumps, electric buses, and EVs, for example, could increase BED's need for new energy resources. Also, if more net-metered solar arrays are installed, BED's energy requirements could be lower than anticipated. Demand response, solar, and battery storage could reduce peak demand relative to expectations. Whether such technologies can offset one another as they are deployed is unknown. At the current anticipated rates of deployment, BED does not envision a scenario in which such beneficial electrification technologies could have a material negative impact on system reliability. As discussed in Chapter 7, BED's current system can support around 80 MW of peak load reliability, which the current high case does not reach. Nevertheless, BED will be monitoring when energy transformation projects are being deployed and the location of such projects to evaluate their impacts, if any, on BED's future energy and capacity needs.

Energy Needs & Resources

BED anticipates that its energy needs will exceed its energy resources from owned and contracted sources by 2025, although this is subject to some risk of lower-than-anticipated output from intermittent resources. Thus, BED will need to acquire additional resources under contract or purchase spot market energy to close the gap that begins in 2025, as illustrated in Figure 2-3 below.

Figure 2-3: Forecasted Load v. Projected Supply Resources as of June 2023



The energy supply gap beginning in 2025 results from the expiration of the Great River Hydro contract at the end of 2024 followed by the expiration of the extended VT Wind contract and the Hancock Wind contract. BED would require replacement contracts to be from renewable resources; preferably from resources located in Vermont, although an extension of an expiring contract for some time cannot be ruled out.

As in previous IRPs, approximately 40% of BED's energy supply is generated by the McNeil Station. BED does not expect this situation to materially change during the IRP planning period. However, a long-term loss of McNeil's electrical output, which is highly unlikely, would significantly alter BED's energy position, causing BED to be substantially at risk to wholesale price fluctuations. Also, the economics of the McNeil facility depend on five key inputs: plant costs, capacity factor, the price of energy, the price of capacity, and the price of RECs (currently CT Class 1). Due to historically low wholesale energy prices, the economics of operating the McNeil Station were challenging in 2020-2021. Recovered energy prices in 2022 and 2023 have returned McNeil to profitability (only considering its wholesale revenues). For additional information concerning the economics of the McNeil plant, please refer to the McNeil study in the appendix.

Hourly Resource Positioning

Although, BED maintains a hedged energy position throughout the year, on an hourly basis BED's position can vary substantially. As shown in the following charts using 2022 data, BED tends to be long in hours when McNeil is running and in the winter. The expiration of the Great River Hydro, Hancock Wind, and VT Wind contracts will likely cause BED to be short in many more hours.

Figure 2-4: Hourly Position Duration Curves, 2022

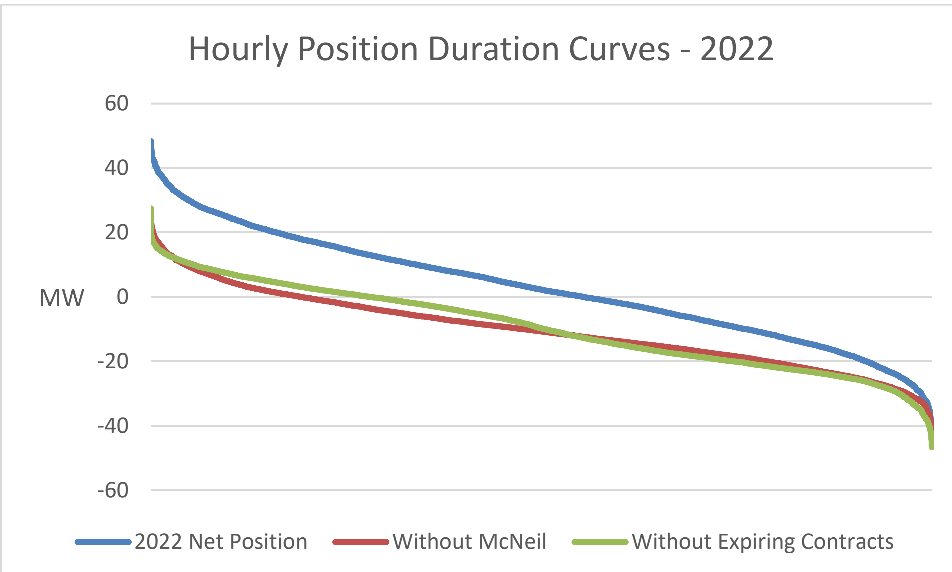


Figure 2-5: Hourly Position Duration Curves, 2022 Winter (Jan-Mar and Dec)

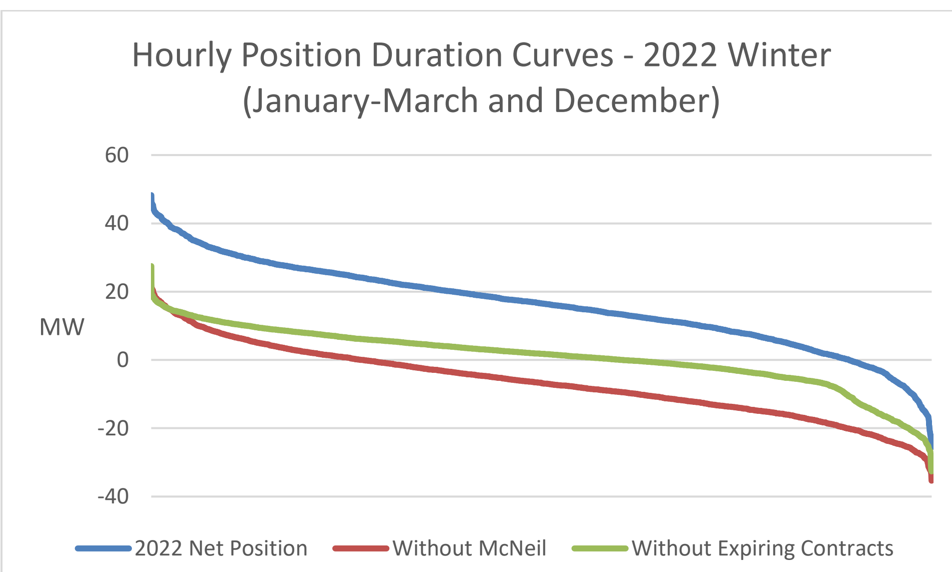


Figure 2-6: Hourly Position Duration Curves, 2022 Off-Peak Months

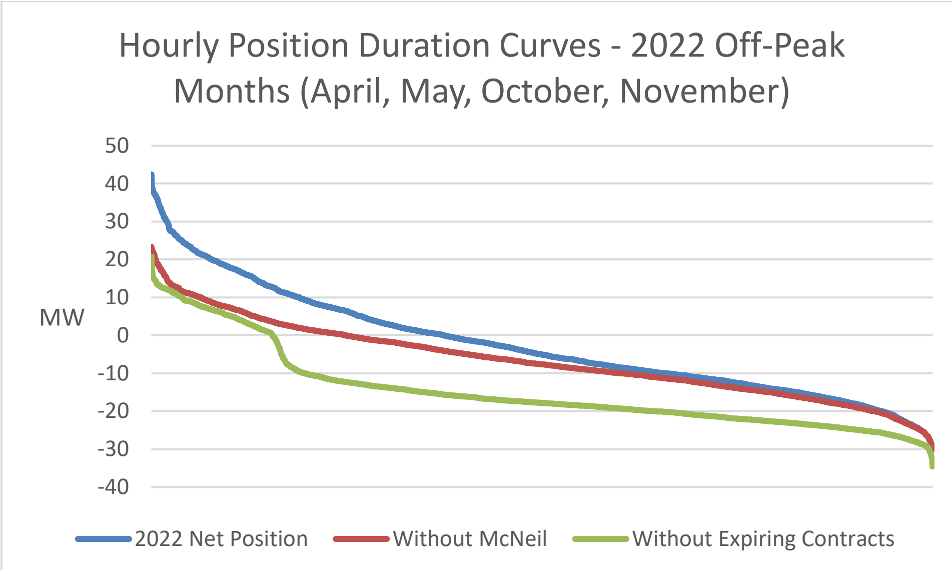


Figure 2-7: Hourly Position Duration Curves, 2022 Summer (Jun-Sept)

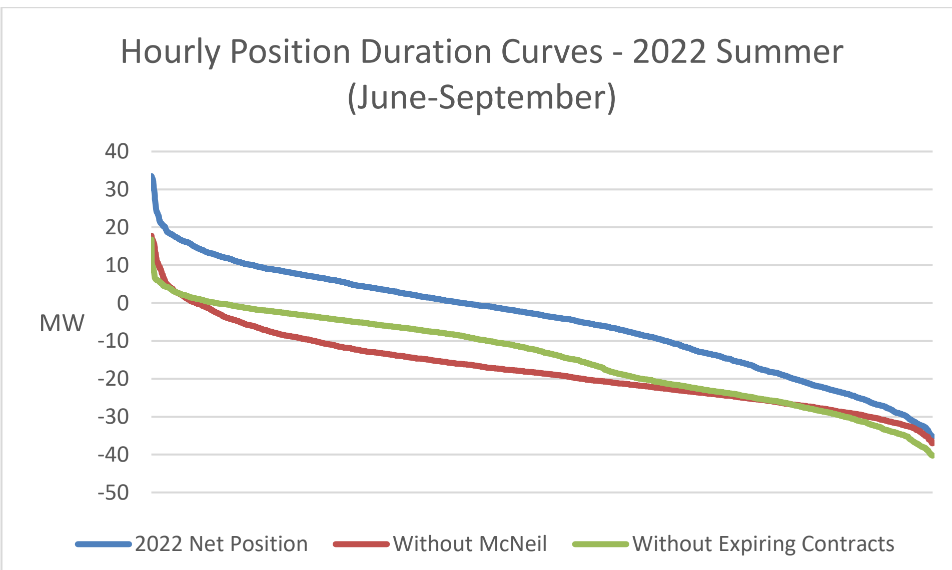


Figure 2-8: 2022 Net Position without Expiring Contracts

Figure 2-9: 2022 Net Position without McNeil

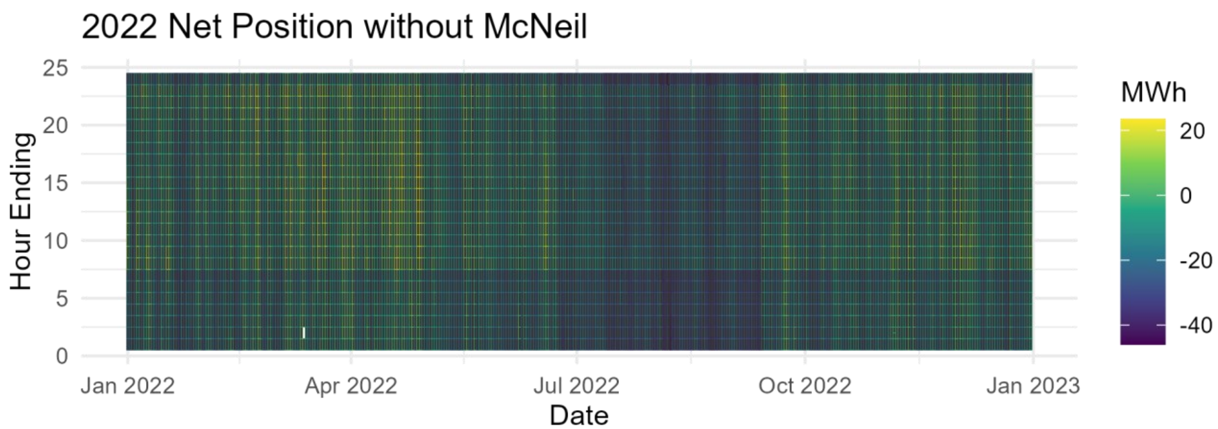
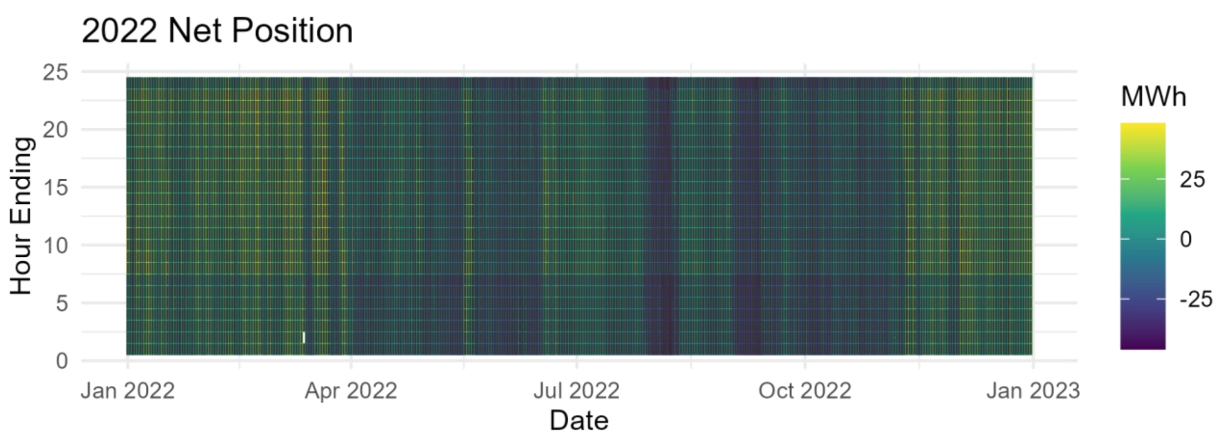


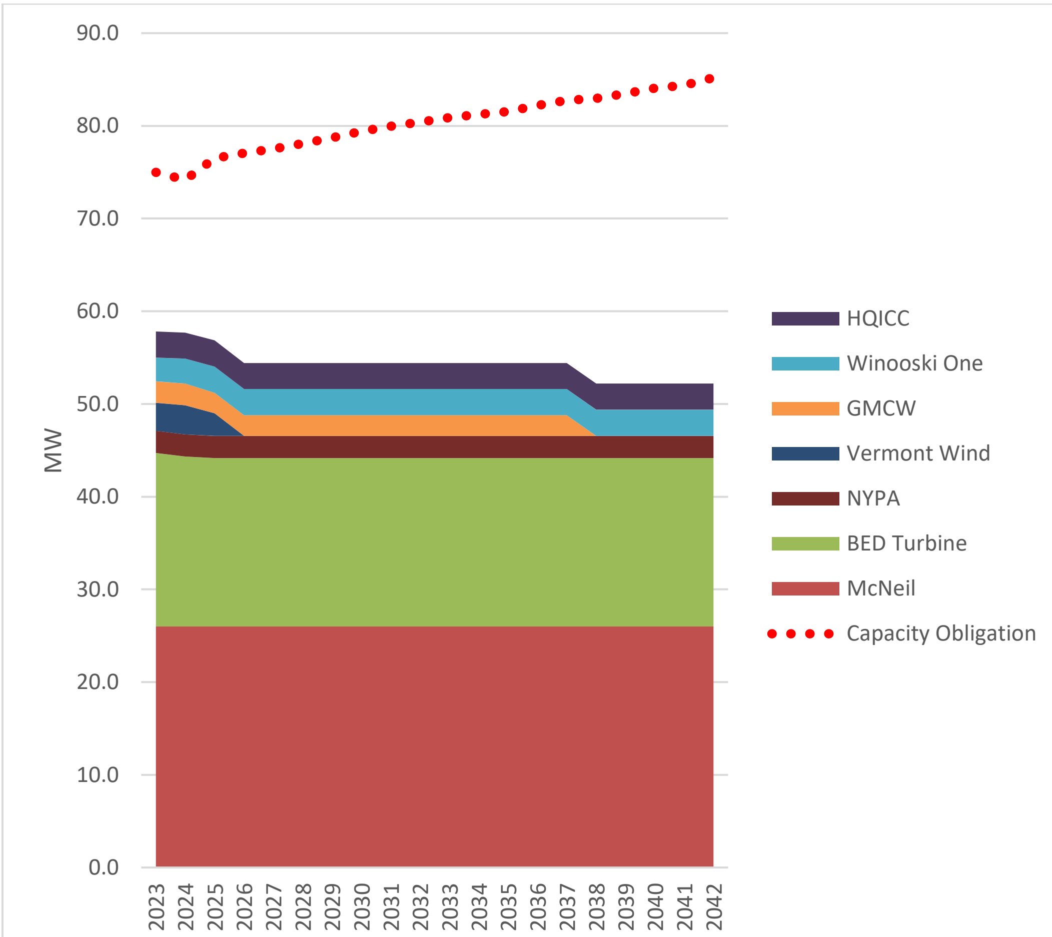
Figure 2-10: 2022 Net Position



Resource Capacity

BED owns and contracts for generation resources sufficient to satisfy roughly two-thirds of its capacity obligation, inclusive of the 15% reliability margin imposed on all distribution utilities by ISO-NE, as shown in Figure 2-11. Of the resources that BED controls, two facilities provide most of the capacity available to comply with regional requirements: McNeil and the GT.[18]

Figure 2-11: BED's Capacity Obligation and Capacity Provided by Generation Resources



To make up the capacity shortfall, BED is required to purchase additional capacity. Such payments are necessary to ensure generators in New England are able to earn revenues during all times of the year even though they may only be needed during the hottest days of the year. This potential for a capacity shortfall is not unique to BED and many other distribution utilities in New England are also required to pay generators for their capacity should it be needed. BED anticipates, as do many other Vermont distribution utilities, that this capacity shortfall situation will persist into the future. Accordingly, BED has undertaken additional evaluations of

[18] BED owns a 50% share of the McNeil Plant.

alternative resources to identify a cost-effective path forward. As discussed in more detail below, these additional evaluations might include building additional capacity resources, contracting with another generator, or pursuing demand response initiatives, including energy storage.

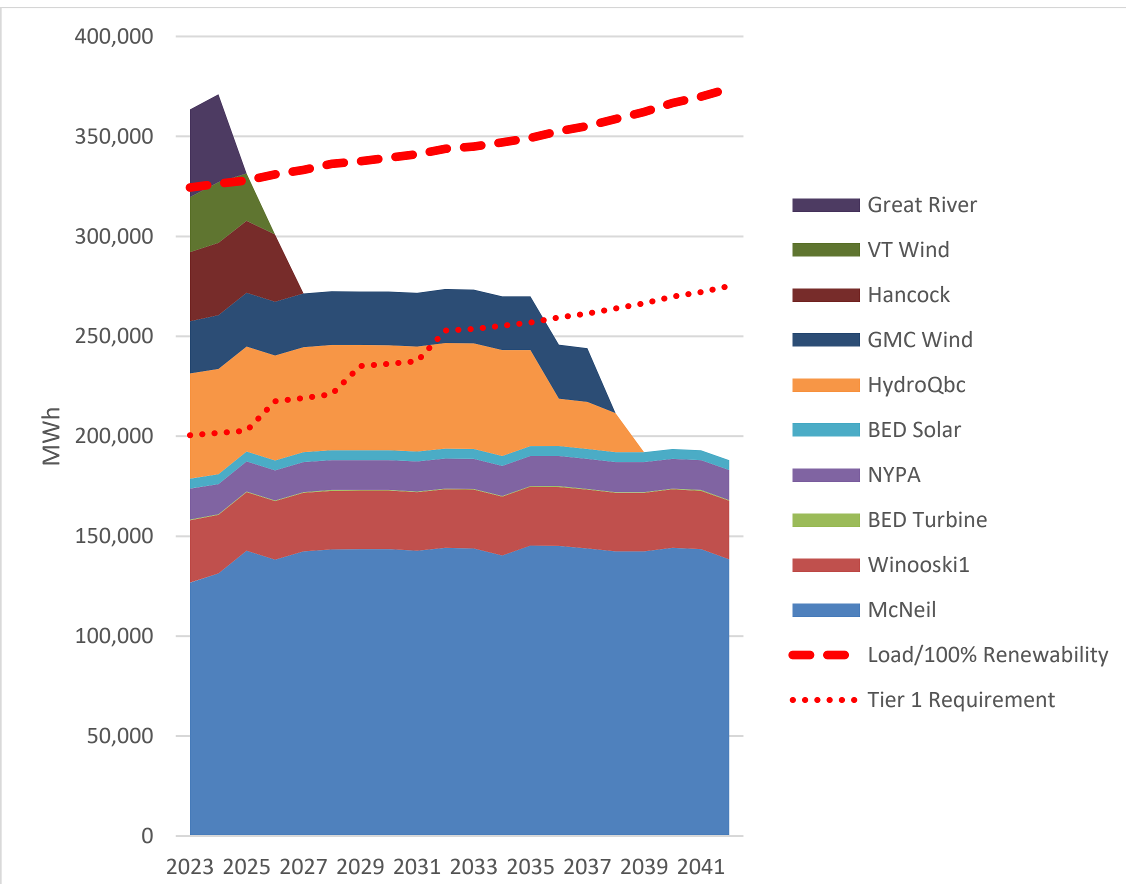
Renewability Needs & Resources

In addition to BED's own commitment to meeting 100% of its energy needs with renewable resources, BED is also subject to Vermont's Renewable Energy Standard (RES). The RES will impact BED's need for specific types of energy resources over the IRP time horizon.

RES Tier 1

With its current resources, BED is in a strong position to satisfy its Tier 1 obligation, which required 55% of retail sales in 2017 (increasing annually to 75% by 2032) to be met with renewable resources. As shown in Figure 2-12, BED expects to be greater than 75% renewable just with its current resources through 2035, however, with its current resources BED will fail to be 100% renewable by 2026.

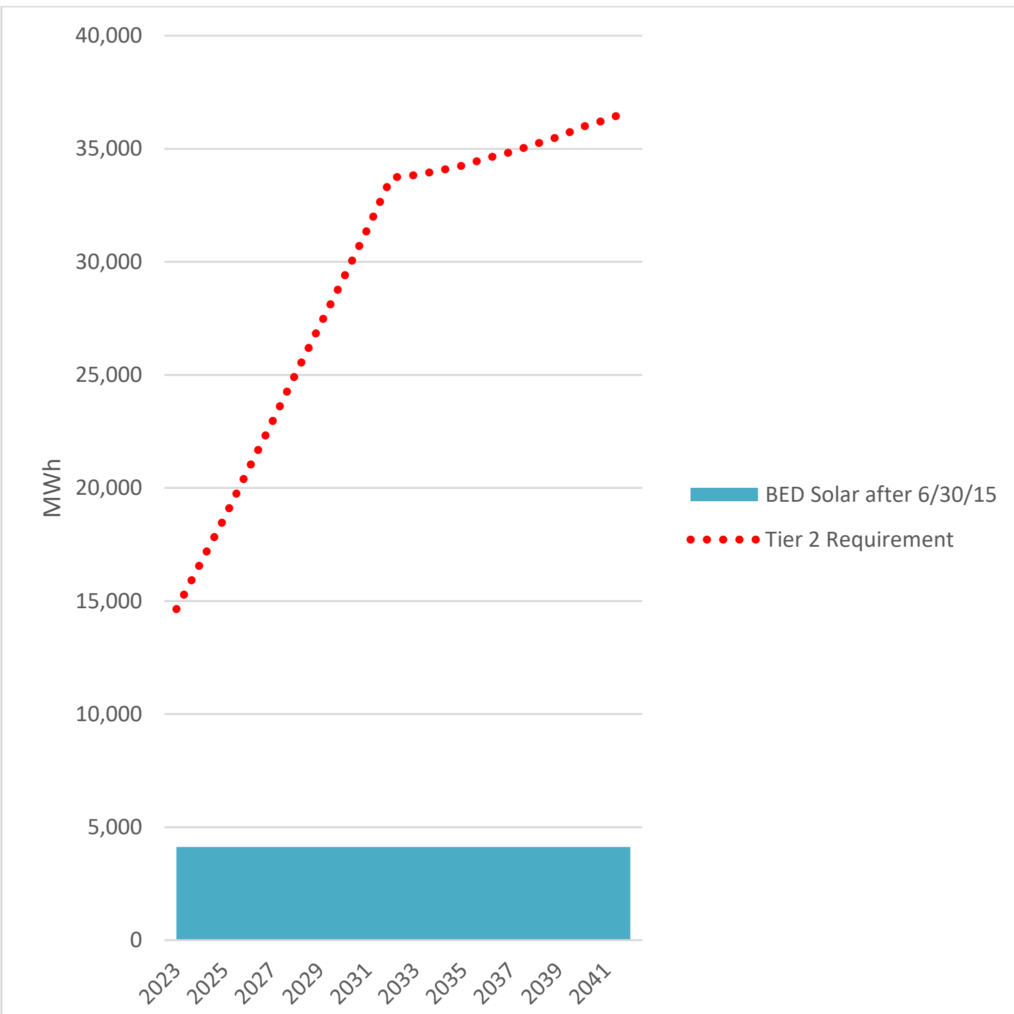
Figure 2-12: BED Tier 1 Requirement and Eligible Resources as of June 2023



RES Tier 2

Because of its 100% renewability, BED is subject to an alternative RES Tier 2 requirement.19 Without such modification, the RES would have required 1% of BED's retail sales (increasing annually to 10% by 2032) to be met with distributed renewable generation. Because of BED's alternative Tier 2 requirement, BED can apply non-net-metering Tier 2 resources to its Tier 3 requirements. To comply with Tier 2, BED must accept net-metering installations and retire the associated RECs it receives. As Figure 2-13 shows, if BED does not maintain its 100% renewability, there may be a large gap between its Tier 2 requirement and Tier 2 eligible resources. In that situation, BED does not anticipate that excess net-metering credits would be available to apply to its Tier 3 requirement.

Figure 2-13: BED Tier 2 Requirement and Eligible Resources as of June 2023



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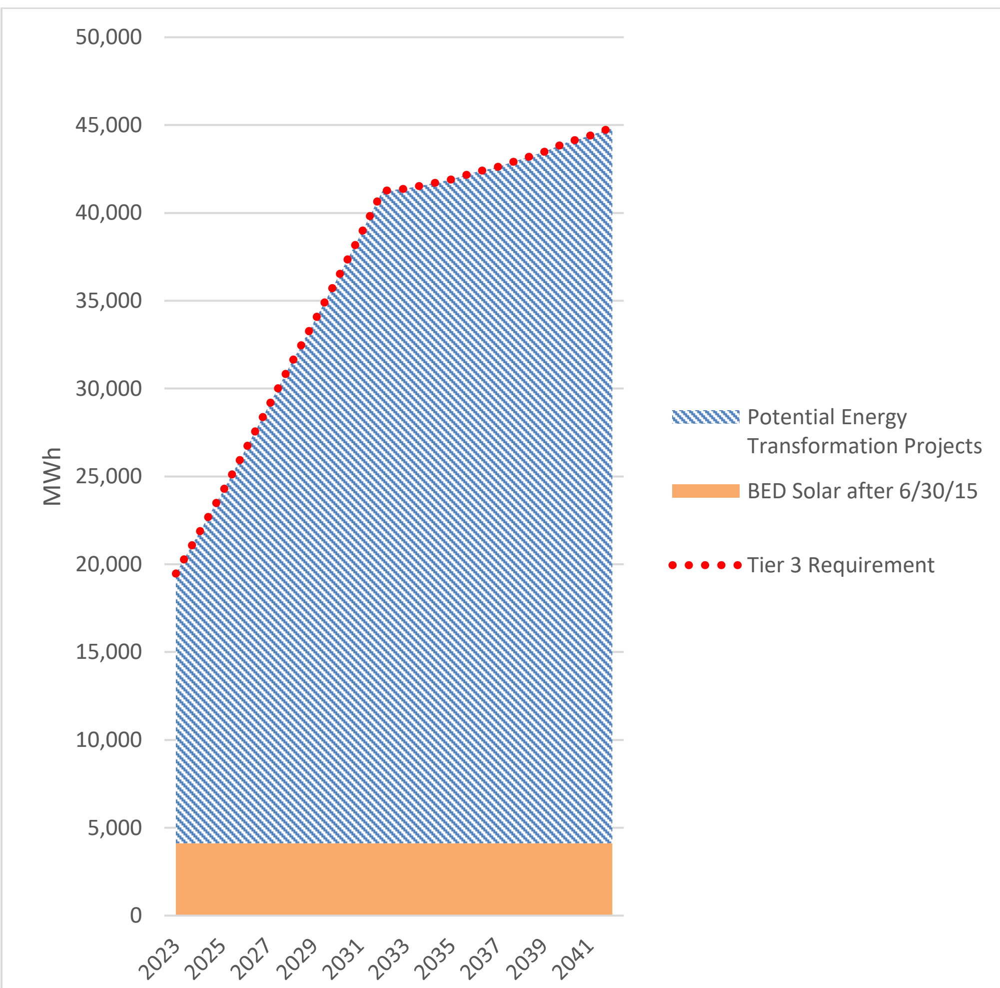
[19] 30 V.S.A. § 8005(b).

RES Tier 3

The Tier 3 requirement, which began at 2% of retail sales in 2017 and increases annually to 12% by 2032, can be satisfied with non-net-metered Tier 2 distributed renewable energy, additional distributed renewable resources, or with "energy transformation" projects that reduce fossil fuel consumption. As Figure 2-14 shows, even when Tier 2 resources are applied to Tier 3, there is a large gap between BED's Tier 3 requirement and its eligible resources. BED has a statutory option under 30 V.S.A. § 8005(a)(3)(G) to pursue reductions in its Tier 3 requirement. BED has not used this option in the past and does not need to use this option in the near future. Based on analyses contained in Chapter 4 (Energy Services), BED has concluded that there is sufficient potential for BED to meet its Tier 3 requirement with energy transformation projects in this IRP planning period. For the first three years that the RES was in effect, however, BED did not reach its Tier 3 requirement with energy transformation projects and relied on REC retirements to avoid alternative compliance payments ("ACPs"). BED has subsequently exceeded its Tier 3 requirement with energy transformation projects in 2020 through 2022.

Figure 2-14: BED Tier 3 Requirement and Eligible Resources as of June 2023



Gap Analysis Findings

A comparison of BED's projected energy and capacity requirements against its available supply resources reveals several key issues:

- Although flat load growth is anticipated to continue well into the future, BED expects that it will need to continue making monthly capacity payments to comply with regional reliability requirements. The price of wholesale capacity could increase substantially if not hedged or actively managed.
- Loss of McNeil, the GT, or both would create a significant financial risk, as BED would be required to make up additional energy and capacity deficits by purchasing resources at wholesale market prices.
- Continued reliance on REC revenue exposes BED to REC market volatility. This would be reduced if McNeil's RECs become less valuable due to changes in their qualification for REC markets.
- Maintaining BED's status as a 100% renewable distribution utility costs more than purchasing wholesale market/system power, which is at historically low prices.
- As a 100% renewable provider, BED complies with Tiers 1 and 2 of the RES. The potential loss of McNeil, which generates up to 40% of BED's renewable energy, could undermine BED's ability to comply with the RES.
- Even if BED maintains its 100% renewability status, current Tier 2 resources can only meet about 10% of its Tier 3 requirements in the later years of the RES. Thus, BED will need to continue to meet Tier 3 requirements with energy transformation projects or acquire Tier 2 resources to meet the Tier 3 requirement.
- If BED is unable to maintain its 100% renewability status and loses eligibility for the alternative Tier 2 requirement, then it would need to acquire significantly more Tier 2-eligible distributed renewable generation resources.

Tier 3 Activities Impact on Energy and Capacity Needs

As described in the Energy Services chapter, BED intends to continue to meet its Tier 3 requirements with multiple energy transformation projects. Many of these projects will add energy loads and could create peak demands to the system over time. In our base case, however, BED expects that the annual electric energy consumption and peak demand requirements of these projects will be minimal relative to our total resources. Additionally, energy efficiency resources will continue to help offset increases in load from such energy transformation projects, as will active demand management resources and new net-metered PV arrays. In general, the inclusion of Tier 3-driven anticipated loads does not change BED's resource questions substantially.

Alternatives Analysis Methodology

The gap analysis highlighted three major issues that needed additional consideration and analysis. These included:

- Effectiveness,
- Accessibility, and
- Costs.

The following section describes BED's methodology and processes for assimilating data as they pertain to our assessment of a potential resource's overall effectiveness, accessibility, renewability, and cost. In general, a resource is deemed effective based on its ability to reliably produce energy and capacity when needed and its renewability. In terms of accessibility, BED considered whether the alternative resource would be available for acquisition during the IRP planning horizon and, if so, at what cost. As an example, BED's efforts did not consider coal as a resource since pursuing a coal strategy would have been incongruent with BED's overall objectives and Vermont's values.

Resource Effectiveness

The extent to which a specific resource can meet BED's projected energy, capacity, or renewability needs is a critical evaluation component. As noted in the gap analysis, BED has unmet needs for both energy and capacity, and has ongoing renewability targets. Generally, the ability for a single resource to meet multiple supply needs is ideal. However, the difference in magnitude between BED's energy and capacity supply needs means identifying a single resource to meet both in a cost-effective manner can be challenging. Further, the intermittent nature of many renewable resources makes them poorly suited as capacity providers, adding to the challenge in meeting renewable energy goals and capacity needs with the same resource.

Energy

There are many types of energy supply resources ranging from highly controllable and dispatchable generators (such as biomass and combined cycle natural gas) to intermittent and uncontrollable renewable resources like solar, wind turbines, and run-of-the-river hydro units. Those resources that are controllable and dispatchable generally have a higher capacity factor and are viewed as more reliable energy resources.

Capacity

Traditional "peaker" resources such as fossil fuel-fired generators may be cost-effective capacity supply resources but are rarely a cost-effective energy supply resource. Some energy-producing resources (typically dispatchable resources) also provide significant capacity resources. However, if the full energy output is not needed or desired, the energy would have to be sold, which leaves a utility vulnerable to wholesale energy market volatility for those sales. For the purposes of this alternative analysis, a resource that effectively meets both BED's energy and capacity needs would be ideal. However, renewable resource capacity supply options are limited and require sales and purchases in the fluctuating wholesale capacity market.

Renewable Energy Standard – Tier 1

In addition to meeting locally developed goals, BED's current 100% renewable position provides important benefits with respect to meeting Vermont's RES and avoiding costly ACPs. Under RES Tier 1, starting in 2017, Vermont utilities were required to source 55% of their energy from renewable resources, increasing annually to 75% by 2032. If a utility is unable to meet this requirement it is subject to an ACP for each kWh it is short of the requirement. Therefore, Tier I renewable resources are a valuable component of BED's portfolio.

Renewable Energy Standard – Tiers 2 & 3

As of 2017, Tier 2 of the RES requires utilities to meet 1% of their retail sales with new Vermont distributed renewable generation with plant capacity of 5 MW or less. This 1% requirement increases annually up to 10% by 2032. Tier 3 of the RES requires utilities to encourage their customers to reduce fossil fuel consumption by an amount equal to 2% of their retail sales in 2017, increasing annually to 12% by 2032. If BED maintains its 100% renewable position, it can meet an alternate Tier 2 requirement as provided in 30 V.S.A. § 8005(b). For both Tiers 2 and 3, any failure to meet the requirements leaves utilities vulnerable to an ACP six times higher than the Tier 1 ACP of $10. Therefore, resources that meet the Tier 2 or Tier 3 requirements provide significant value to BED.

Environmental Impact

The 2022 Vermont Comprehensive Energy Plan Guidance for Integrated Resource Plans and 202(f) Determination Requests (April 2023), section 2.3.7 directs utilities to "identify the environmental impacts of all resources, including where applicable the quantities of air pollutants (including but not limited to greenhouse gases), liquid wastes, and solid wastes." As a utility with 100% renewably sourced energy[20] and a 2030 Net Zero Vision,[21] BED is continually looking for ways to minimize its negative environmental impacts and maximize its positive impacts.

Equity and Environmental Justice

The 2022 Vermont Comprehensive Energy Plan Guidance for Integrated Resource Plans and 202(f) Determination Requests (April 2023), section 2.3.8 directs utilities to "identify what

[20] https://www.burlingtonelectric.com/our-energy/, accessed July 2023

[21] https://www.burlingtonelectric.com/nze, accessed July 2023

communities may be most impacted by the resource, including how any benefits and/or burdens associated with the resources may be distributed. Note any efforts that could be made to mitigate burdens associated with the resources particularly those on frontline and impacted communities. Describe how the utility has or would engage with impacted communities and any data or metrics they intend to use to evaluate such impacts." As a municipally owned utility in a city with a Racial Equity Strategic Roadmap,[22] BED engages with its community regularly, with a focus on equity and environmental Justice. In 2022 BED hired a Project & Equity Analyst to dedicate resources to this effort.

Resource Access

BED assesses each potential resource for its availability, meaning that BED could access it through typical utility mechanisms and without extraordinary measures or unusual circumstances. Each resource is also evaluated based on whether BED could reasonably expect to have the opportunity to own it (or a portion of it) or conversely, whether BED would have to own it in order to have access to it. In all cases, greater availability is viewed positively.

Resource Cost

Resource cost analysis of a potential resource is composed of an evaluation of any initial and ongoing costs, as well as an assessment of whether the resource is consistent with BED's internally developed goals. In all cases, lower initial and ongoing costs are preferable.

Initial Cost

In most cases, the initial cost is the upfront capital cost associated with purchasing or constructing a resource. These costs are typically financed over a long period of time and are fixed as opposed to ongoing cost which can be variable based on resource output.

Ongoing Costs

Ongoing costs can be fixed and variable. Fixed ongoing costs can include property taxes and standard operating and maintenance costs. Variable costs can include transmission and wheeling fees. Most ongoing costs apply whether the resource is owned or a power purchase agreement ("PPA").

Consistency with BED Goals

BED and the City of Burlington have a long-standing commitment to innovation and the protection of the environment, as demonstrated by BED's achievement of 100% renewability and commitment to achieve the City's NZE by 2030 goal. BED considers the extent to which each potential resource will further these goals. While it is not necessarily feasible to

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22 https://www.burlingtonvt.gov/sites/default/files/Burlington%20Racial%20Equity%20Strategic%20Roadmap_Spread.pdf, accessed July 2023

quantify this value, consistency with BED's goals may make an otherwise more expensive resource based on initial and ongoing costs more attractive than a lower-cost resource. While non-renewable resources will not advance BED's renewability goals, consideration of such resources does, at a minimum, provide a useful benchmark for cost comparison with renewable resources. Additionally, non-renewable resources provide value as capacity providers as long as they are not used for production of any material amount of energy annually (i.e., they are only being used to serve reliability versus energy needs).

Resource Risk

There are cost risks associated with every generation and supply resource alternative. Some risks, such as variable fuel, maintenance, or capital costs, are easy to quantify while others are more difficult, such as potential regulatory changes. BED has completed the following review of known and anticipated risks of each potential resource to assess the most likely financial and societal costs.

Resource Environmental and Locational Considerations

BED staff has been working on a draft metric that combines a resource's direct land use requirements and weighted distance from load metric for evaluating competing resource options. This metric does not monetize this value but does reduce it to a numeric value for comparisons. This metric is available in draft format for discussion in future decisions but needs additional development. BED's Strategic Direction calls for expanding local generation and serving energy needs in a socially responsible manner. Most of BED's energy is now produced in Vermont, and about half is produced in Burlington. BED continues to work on tools to explicitly calculate the relative merits of power portfolios based on both their location and environmental impacts.

Alternatives Analysis

This section provides a description of each resource followed by a summary of each resource's overall effectiveness, accessibility, and cost. These summaries are used to complete the Generation & Supply Alternatives Matrix located at the conclusion of this chapter, which compares selected resources to one another. This comparative analysis helps to determine which resource options have the greatest potential for meeting the public's need for energy services at the lowest present value costs, including environmental and economic costs.

To evaluate and compare resource options, BED assembled the capital cost, fixed and variable operating and maintenance ("O&M") cost, and levelized costs using the levelized cost of energy analysis performed by Lazard in 2023.[23] BED also issued a request for proposals for renewable resources in 2022, which resulted in proposals for solar and storage. The solar proposals were

[23] https://www.lazard.com/media/2ozoovyg/lazards-lcoeplus-april-2023.pdf,accessed June 2023

generally in the price range for those categories of resource alternatives in Table 2-3 below; storage proposals were higher priced.

Table 2-3: Potential Resource Alternatives

Plant Type	Net Output (MW)	Capital Cost ($/kW)	Fixed O&M Cost ($/kW-year)	Variable O&M Cost ($/MWh)	Levelized Cost ($/MWh)
Solar	150	1,050	11	0	60
Wind-Onshore	175	1,363	28	0	50
Wind-Offshore	1,000	4,000	70	0	106
Storage	100	596	20	0	250
Gas-Peaker	145	925	12	0	168
Gas-Combined Cycle	550	975	14	4	70

To evaluate the value of capacity supply options across all types of resources, the 2022 capital cost per kW of each resource was converted into a cost per kW-month value, as shown in Table 2-4 below. This analysis indicates that the lowest discounted cost resource is any natural gas plant located in New England. By way of comparison, ISO-NE market processes have also estimated that the cost to construct a new natural gas fired power plant would be approximately $9.078/kW-month to build.[24] This cost benchmark is oftentimes referred to as the "cost of new entry" or the CONE value. However, in the most recent FCM auction, FCA 17, generation cleared at $2.59/kW-month, well below the current CONE value.[25] This data suggests that new generators can enter the New England market for capacity at or below today's CONE values.

Table 2-4: Alternative Resources Capacity Cost Evaluation

Plant Type	Capital Cost ($/kW)	Cost ($/kW-month)	Assumed ISO-NE Discount (Capacity Market MW/Nameplate MW)	Discount (ISO-NE) Cost ($/kW-month)
Solar	1,050	5.83	8%	77.16
Wind-Onshore	1,363	7.57	28%	26.88
Wind-Offshore	4,000	22.22	41%	54.79
Storage	596	3.31	74%	4.45
Gas-Peaker	925	5.14	83%	6.17
Gas-Combined Cycle	975	5.42	83%	6.50

[24] https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/, accessed June 2023

[25] https://www.iso-ne.com/about/key-stats/markets#fcaresults, accessed June 2023

Although wholesale capacity costs may be relatively low at present, BED remains concerned that current low prices may be fleeting. To reiterate, BED's capacity-related price exposure is low for the next three to four years due to low cleared capacity market prices. At this point, BED's capacity price risk after the currently cleared auctions would be mostly upside risk, but the current capacity market structure would reveal price changes with three years' warning, which would allow for potential mitigation activities prior to incurring capacity charges.

In addition to the resources listed below, BED has access to energy and capacity resources through the wholesale markets operated by ISO-NE. Net wholesale energy and wholesale capacity purchases occur automatically under the ISO-NE market structure and can be viewed as a "do nothing" option.

Below, BED analyzes a series of resource types: Biomass, Solar, Wind, Storage, Combined Cycle Natural Gas, Traditional "Peaker," and Long-Term contracts.

Biomass

In this analysis, "biomass" refers to using waste wood or sustainably sourced/harvested wood/plant-based materials to generate energy. For the purposes of the alternatives analysis, BED's current share of McNeil is classified as "existing biomass," while "additional biomass" refers to the procurement of some portion of the 50% share of McNeil not currently owned by BED.

Effectiveness

Energy

BED has direct expertise with generating biomass energy at McNeil. For 36 years, McNeil has provided reliable and flexible energy supply resource and participated in the day-ahead and real-time wholesale energy markets. McNeil's capacity factor ranges from 55%-70%, allowing BED to meet approximately 40% of its energy needs with generation from McNeil. For the purposes of this analysis, we increased the share of BED's energy needs produced by McNeil proportionally over time. On a day-to-day basis, however, BED tends to be long on energy when McNeil is running, and short when it is not. Acquiring an additional share of McNeil would exacerbate this issue.

Capacity

McNeil's qualified capacity rating according to ISO-NE's FCM ranges from 52 to 54 MW (full nameplate capacity). McNeil is entered into the FCM as a self-supply resource for BED; providing 26 MW of capacity supply that BED can consistently rely on to meet its capacity requirement.

Renewability

Powered by locally sourced biomass, McNeil energy qualifies under the CT Renewable Portfolio Standard and each MWh of energy generated creates a CT Class 1 REC. Additionally, McNeil's energy qualifies as renewable under Tier 1 of the Vermont RES.

Environmental Impact

McNeil's environmental impact is discussed in more detail in the McNeil section of this IRP's appendix and in several publicly available reports conducted by third parties.[26] McNeil is equipped with a series of air quality control devices that limit the particulate stack emissions to one-tenth the level allowed by Vermont state regulation. McNeil's emissions are one one-hundredth of the allowable federal level. The only visible emission from the plant is water vapor during the cooler months of the year. In 2008, McNeil voluntarily installed a $12 million Regenerative Selective Catalytic Reduction system, which reduced the NOx emissions to one-third of the state requirement. Based on Environmental Protection Agency and Intergovernmental Panel on Climate Change carbon accounting protocols, third-party analysis finds that McNeil's net impact is carbon neutral because its sustainable forestry and harvesting practices offset the combustion impacts. BED believes that McNeil's net-carbon neutrality along with its dispatchability and renewability makes it a preferable option compared to natural gas generation, which would be McNeil's likely generation resource replacement.

Equity and Environmental Justice

As electricity generated by a municipal utility using locally sourced biomass that generally serves to displace electricity generated by fossil fuel power plants, continued operation of McNeil would likely have positive equity and environmental justice impacts. The total aggregate impact of McNeil's operations would not change with a change in ownership.

Access

Availability

While BED has a 50% ownership share of McNeil, the other 50% is shared among two entities: Green Mountain Power (31%) and Vermont Public Power Supply Authority (19%). The three owners meet quarterly and maintain open lines of communication regarding the facility's operations and finances. In that regard, BED has direct and frequent access to the parties who could make additional biomass resources available. BED could discuss options with the joint owners to access a greater share of McNeil's energy, capacity, or both.

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[26] https://www.burlingtonelectric.com/mcneil/, Accessed July 2023

Ownership

As noted above, BED has an existing ownership share and a direct relationship with the other joint owners, making ownership of additional biomass possible from an access standpoint.

Cost

Initial Cost

If BED pursued a greater ownership share, there would be potential for significant initial costs related to "buying out" current joint owner shares. This cost would be less if instead BED were to enter into a contract to purchase a joint owner's share of energy or capacity, but not full ownership rights. However, the price of a buy-out is dependent on the potential seller's interest.

Ongoing Cost

BED has firsthand knowledge of McNeil's current operating and maintenance costs. When compared to other controllable and dispatchable energy supply resources, McNeil's variable costs are relatively high. As BED manages the sale of McNeil's CT Class 1 RECs for both BED and GMP, BED is aware of the importance of REC revenue in helping McNeil remain a cost-effective energy supply resource by offsetting the cost of production. Falling REC prices would essentially make McNeil more expensive to operate. BED also anticipates that inflationary pressures on maintenance costs and capital expenses will continue in the coming years.

Consistency with BED Goals

An increase in BED's share of McNeil generation would further BED's renewability and sustainability goals by assisting with maintaining 100% renewability and meeting RES Tier 1 requirements.

Risk

Biomass is different from other renewable resources like solar and wind because it requires fuel, it is dispatchable, and it requires installation of technology to capture combustion pollutants. Accordingly, the eligibility of McNeil's RECs for various New England renewable policy markets are tied to McNeil's combustion pollutant capture technologies and to the sustainability of its fuel. If more stringent regulations with respect to fuel, emissions, or biomass are implemented, McNeil's renewability classification and availability of high value RECs and RES compliance could be impacted. With BED already relying on McNeil for 40% of its energy supply, greater reliance on McNeil could increase BED's exposure to the resulting market impacts in the event of such regulatory changes.

Conclusion

The most viable option for BED, if it were to desire additional biomass energy, would likely be to seek to buy out some or all of one or more of the other Joint Owners' entitlements. However, this would carry some additional single resource risk and BED does not intend to pursue this at this time.

Potential considerations for acquiring additional biomass resources from McNeil are:

- McNeil is a reliable renewable energy and capacity resource that furthers BED's goals and current RES requirements.
- BED has a high level of access to the resource and could investigate shorter term non-ownership options to avoid high initial costs or a higher share of future capital expenditures. BED could also consider increasing its ownership share of McNeil, if one of the other Joint Owners sought to reduce their ownership share.

Potential risks of acquiring additional biomass resources from McNeil:

- In terms of cost, McNeil already has relatively high operating costs, with the potential for its net expenses to increase in the event of declining REC revenue in the future.
- Increased reliance on McNeil would expose BED to greater risk in the event of regulatory changes and resulting REC market impacts.

Solar

For the purposes of this analysis, BED considered all scenarios for solar purchases in which BED would be entitled to some portion of the output.

Effectiveness

Energy

In the northeastern U.S., stand-alone solar has a capacity factor of approximately 15%. This relatively low capacity factor makes solar alone unlikely to provide a good hedge for energy prices. As BED tends to be long on energy in the winter and short on energy in the summer, solar has the potential to help BED hedge its energy needs on a seasonal basis.

Capacity

Small solar facilities that are less than 5 MW generally do not participate in ISO-NE's FCM. Passive reductions of BED's loads from solar at times when charges for capacity are set allow smaller solar to serve as a capacity resource. Increased behind-the-meter solar has shifted the ISO-NE peak to later in the day, which has reduced its capacity benefit. Larger solar can also provide capacity, but ISO-NE's current market rules recognize solar at approximately 10% of nameplate capacity. In addition, in April 2023, ISO-NE presented results showing that solar would receive even less capacity value under its marginal reliability impact calculations.[27]

Renewability

Solar PV is a Tier I eligible renewable resource. Additionally, distributed generation facilities that are less than 5 MW in capacity are Tier 2 eligible resources. Such facilities that are not net metered[28] are also Tier 3 eligible.[29] Accordingly, RECs produced by BED's non-net-metered solar resources can also be sold to provide revenue to BED.

Environmental Impact

Although solar does have environmental impacts, adding a new solar resource should generally serve to displace fossil fuels, and therefore have a net positive impact. The exact impact will depend on the details of the solar project.

Equity and Environmental Justice

As a purchase through a municipal utility that would generally serve to displace fossil fuels with local generation, the creation of additional solar would likely have positive equity and environmental justice impacts.

Access

Availability

BED has supported development of several solar projects in the City of Burlington. By its nature, solar distributed generation is smaller in scale and requires less land for siting purposes than utility-scale generation. While Burlington is a densely populated area with limited open land, there are further opportunities for solar development on rooftops and brownfields within the City. With additional siting potential and the continued decline of the cost of solar panels, BED views solar PV development as an available resource.

Ownership

BED currently owns two behind-the-utility meter solar arrays and has experience developing such projects. The City of Burlington owns many buildings and land within the City, making BED acquisition and development of additional solar PV arrays feasible.

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[27] https://www.iso-ne.com/static-assets/documents/2023/04/a05f_mc_2023_04_11-13_rca_impact_analysis.pptx, accessed June 2023

[28] 30 V.S.A. § 8005(b)

[29] BED must retire all net-metering RECs to meet its 30 V.S.A. § 8005(b) alternative Tier 2 compliance requirement.

Cost

Initial Cost

Among the renewable resource options considered, a distributed generation solar PV array has the highest initial cost at approximately $1,000 per kW of installed capacity.

Ongoing Cost

The ongoing cost of a solar array consist solely of fixed O&M costs of $7-$14 per kW-year. The levelized cost of energy for utility-scale solar ranges from $24-$96 per MWh in the Lazard study. Distributed generation resources of less than 5 MW are eligible under Tier 2 and could be applied to Tier 3, helping BED avoid an ACP under the RES.

Consistency with BED Goals

Solar arrays would be consistent with BED's renewability goals and could support BED's maintenance of its 100% renewable status. its NZE target.

Risk

Because ISO-NE is currently summer peaking during daylight hours, solar functions as a reasonable capacity resource, reducing load during peak periods. As more solar resources have come online, the ISO-NE peak has shifted later in the day, moving beyond the time of the greatest solar production. Therefore, the energy and capacity value of solar could decrease as more solar is deployed.

Conclusion

While solar has a low capacity factor, particularly in the Northeast, solar can serve as a capacity resource by reducing load during the ISO-NE peak or by directly participating in the ISO-NE Capacity Market. As noted above, non-net-metered solar PV under 5 MW is also an eligible Tier 2 resource which could help BED meet its RES Tier 3 requirement. In terms of BED's renewability goals, solar PV could be an effective resource. However, given BED's urban landscape and ISO-NE market rules, BED expects that solar development in Burlington will, in large part, be net-metered solar on building rooftops. Solar generation resources that are developed in other utility service territories are more costly for BED than those in BED's territory due to transmission (i.e., "wheeling") charges by the host utility, except when the solar generation is directly connected to the high-voltage transmission system.

Wind

For the purposes of this analysis, utility-scale wind refers to onshore and offshore wind farms consisting of multiple, large wind turbines that have a combined nameplate capacity of 10 MW or more. According to ISO-NE, as of 2023 there were 19,849 MW of wind resources in its interconnection queue, the vast majority of which is offshore.[30]

Effectiveness

Energy

Wind generation is an intermittent resource that can exhibit rapid changes in its production due to weather. Onshore utility-scale wind farms have historically sustained capacity factors of 25%-35% over time. Offshore wind is expected to achieve even higher capacity factors. For example, the Block Island Wind Farm attained a 45% capacity factor in 2019.[31]

Capacity

Due to its intermittent nature, ISO-NE does not define wind as an effective capacity supply resource. Because wind resources are not controllable and thus cannot be assumed to be available at times when energy demand is highest, ISO-NE "de-rates" wind generators' nameplate capacity when it assigns a qualified capacity ("QC") rating. During ISO-NE's pay-for-performance events,[32] all three of BED's wind resources produced above their ISO-NE's capacity ratings and commitments (with one exception in the second event).

Renewability

Wind is a fuel- and emission-free renewable resource. Wind resources qualify for high value RECs in multiple markets throughout New England and nationally. Wind therefore qualifies as an eligible resource to meet BED's RES Tier 1 requirement.[33]

Environmental Impact

Although wind does have environmental impacts, adding a new wind resource should generally serve to displace fossil fuels, and therefore have a net positive impact. The exact impact will depend on the details of the wind project. Onshore wind tends to have some of the lowest lifecycle CO2 emissions.[34]

Resource Equity and Environmental Justice

As a purchase through a municipal utility that would generally serve to displace fossil fuels, the creation of additional wind resources would likely have positive equity and environmental

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[30] https://www.iso-ne.com/about/regional-electricity-outlook/, accessed June 2023

[31] EIA Form 923, https://www.eia.gov/electricity/data/eia923/

[32] The two only Pay-for-Performance events occurred on Labor Day 2018 and Christmas Eve 2022. More information on Pay-for-Performance is here: https://vimeo.com/257500308, accessed June 2023.

[33] Due to restrictions on facilities 5 MW and greater, large-scale wind is not available for Tier 2 or 3 purposes.

[34] https://www.ipcc.ch/site/assets/uploads/2018/02/ipcc_wg3_ar5_annex-iii.pdf#page=7, Accessed July 2023.

justice impacts. That said, onshore wind siting has been problematic, and would likely involve a developer needing to deeply engage with any impacted communities.

Access

Availability

There are currently five utility-scale wind farms in Vermont: Searsburg Wind Facility (6 MW), Georgia Mountain Community Wind (10 MW), Sheffield Wind (40 MW), Deerfield (30 MW), and Kingdom Community Wind (63 MW). BED currently purchases energy from Georgia Mountain Community Wind, Vermont Wind, and Hancock Wind for 100%, 40%, and 26% of their respective outputs. As noted above, BED views wind resources favorably on multiple levels (energy output, cost, renewability, access etc.), but new resources are unlikely to be available at the utility scale in Vermont.

Ownership

While BED has three existing wind contracts, it does not currently own any utility-scale wind facilities. However, as new resources are built in the ISO-NE region, BED may consider additional purchase power arrangements if warranted.

Cost

Initial Cost

Of the renewable resources evaluated, wind has the potential to provide some of the lowest-cost energy on a per kWh basis due to its moderate initial cost and low ongoing costs (i.e., its absence of a fuel cost). According to the above tables, capital costs range between $1,025/kW and $1,700/kW for onshore wind. Our research also indicated that the cost of wind turbines has decreased in recent years and is anticipated to continue falling over the next several years.

Ongoing Cost

Compared to other fuel-free renewable resources, the fixed O&M costs of wind can be relatively high. However, on a levelized energy cost basis, onshore wind appears to be among the lowest cost renewable energy resources and is reaching cost parity with combined cycle natural gas generators. Offshore wind costs are also expected to continue to decline as developers gain experience building systems and larger systems reach economies of scale relative to conventional generators.

Consistency with BED Goals

As a renewable and zero-emission resource, wind is consistent with and supportive of BED's goals. The existence of wind resources in Vermont and the continued development of new wind resources in New England also suggests that wind resources would continue to be available as an ongoing component of BED's 100% renewable energy portfolio. However, it should be noted that what is effectively a moratorium on new VT wind resource development means new wind resources are unlikely to be developed near BED's load in the near-term.

Risk
Wind generation production is subject to weather conditions. As a utility increases the proportion of its load met with such intermittent resources, it must consider methods to smooth out this intermittency by procuring other resources during lower wind generation times. Increasingly affordable storage technologies could help address the issue in the future, but in the meantime, greater reliance on intermittent resources like wind could increase BED's exposure to wholesale energy prices.

Conclusion
Despite its intermittency, BED views wind generation as a moderately strong energy resource, and a less-effective capacity supply resource. Levelized energy costs for wind are becoming increasingly competitive, and offshore wind is becoming a cost-competitive resource for other New England states to reach their respective renewability targets. Additionally, wind generates high-value RECs that can generate utility revenue or be used to meet RES Tier 1 requirements.

Storage and Load Control
Energy storage and load control can take many forms, including several types of batteries and a wide variety of controllable loads. Storage and load control are both resources that can operate both as a supply resource and a load resource.35 This analysis discusses a 10 MW of capacity/40 MWh of energy storage ("10 MW/40 MWh"), utility-scale, ISO-recognized lithium-ion battery storage system that could replace a fossil-fuel powered peaking unit. Load control would likely be on a smaller scale in BED's service territory but have similar characteristics (including the ability to add or reduce load and being a better capacity than energy provider). A key characteristic of any storage or load control is the rate that it is discharged relative to its maximum capacity (also known as "C rate"). Generally, there is a tradeoff between cost and C rate, where a storage device is more expensive the longer it can discharge. Recently, Long-Duration storage pilots (which can discharge for a day or more) have been announced by the Department of Energy with funding from the Bipartisan Infrastructure Law. BED will continue to monitor those developments, but generally the economics of behind-the-meter batteries have favored multi-hour discharge times.

[35] "How Energy Storage Can Participate in ISO-New England's Wholesale Electricity Markets," page 3, ISO-New England, March 2016.

Effectiveness

Energy

A battery storage system does not generate electricity, but rather serves as a control device that allows a utility to dispatch its stored energy when needed or to capture and store energy at times of surplus intermittent renewable generation. Further advantages of storage are its ability to respond quickly to rising demand, participate in the day-ahead and real-time energy markets, and provide various grid services such as regulation services.[36]

Lithium-ion batteries are considered to have relatively high energy density, meaning the amount of energy capable of being discharged is high compared to its physical volume. While lithium-ion batteries are among the most efficient batteries available, with efficiency ranging from 80%-93%, losses do occur when energy is stored and later discharged (meaning not all of the generation a battery stores will be discharged as usable electricity) and as a result, additional generation is necessary to offset this loss. The battery configuration considered in this analysis is intended to offset a peaker unit, and therefore is not anticipated to serve as an energy supply resource, other than by adding supply during BED's on-peak periods and decreasing supply during BED's off-peak periods.

Capacity

A battery's power density, or its capacity to discharge energy over a specific period (e.g., 1 hour, 1 day, etc.) is an important consideration when assessing it in the context of a utility's capacity obligations. While battery storage may not be a net producer of energy, as discussed above, it does have the ability to move energy in time and, consequently, can act as a capacity resource for distribution utilities. The battery system considered in this analysis could discharge a sustained 10 MW for four hours. To compare battery storage to other capacity supply resources, it is important to consider the cost per kilowatt-month. The battery storage peaker unit is estimated to cost $3.31/kW-month, which is below the $5.14/kW-month of a traditional peaker unit, but above the most recent FCA clearing price of $2.59/kW-month. A battery storage facility, however, could potentially provide value streams by providing frequency regulation or transmission cost reduction.

Renewability

The renewability of a battery storage system depends on the source of energy used to charge the batteries. Because 100% of BED's energy is from renewable resources, a battery storage system located within the BED distribution system would assume that same level of renewability. If BED no longer sourced 100% of its energy from renewable resources, and

[36] "How Energy Storage Can Participate in ISO-New England's Wholesale Electricity Markets," page 5, ISO-New England, March 2016.

assuming the batteries were not directly charged from a renewable resource, the storage system would be assigned the same proportion of renewability as the rest of the BED load. However, because battery storage is not an energy generator, it would not help BED meet its Tier 1 or 2 requirements. It could, however, help meet BED's Tier 3 requirements based on reducing the need for peaking generators and emissions during on-peak times.

Environmental Impact

Although storage does have environmental impacts, adding a new storage resource should generally serve to displace fossil fuels, and therefore have a net positive impact. The exact impact will depend on the details of the renewable generation facility's energy it stores. Load control would likely have minimal initial impacts as it would involve turning existing devices such as EVs or building control systems into grid resources.

Equity and Environmental Justice

As a purchase through a municipal utility that would generally serve to displace fossil fuels, the creation of additional storage and load control would likely have positive equity and environmental justice impacts. Customer-sited storage or load control would also provide an opportunity for customer participation, potentially furthering equity goals.

Access

Availability

Storage technologies are continually evolving. As of June 2022, 6,000 MW of battery storage was proposed in the ISO-NE region.[37] It is likely that BED could acquire access to storage in the future. The siting of such a storage facility within the ISO-NE region, with future availability to BED, appears to be feasible with locating such a resource in Burlington appearing viable as well.

Ownership

While not immediately anticipated, it is possible that BED could acquire a 10 MW/40 MWh battery storage system or share ownership of a larger system in the future. ISO-NE has indicated it anticipates energy storage to become an increasingly important part of the regional power system and has released information on how battery storage units can participate in its wholesale energy markets. BED anticipates battery storage systems will become more prevalent in future years as costs continue to decline.

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[37] "2022 Regional Electricity Outlook," page 15, ISO-New England, June 2023.

Cost

Initial Cost

Like renewable technologies, the cost of battery storage has fallen substantially in recent years and continued falling prices are expected over the next several years. At present, battery storage is around the cost of a traditional peaker unit of similar capacity. Note that this estimated initial cost appears to be consistent with the ongoing costs estimated for a full tolling storage PPA (discussed in greater length in the Decision Chapter).

Ongoing Cost

The estimated levelized cost of storing and discharging energy from a 10 MW/40 MWh battery storage peaker unit is $215-$285 per MWh. This cost is well above all the other supply resource options evaluated except gas peaking plants. As noted above, the capital costs of storage are expected to continue to fall, which will help make battery storage more economical on a levelized cost basis in the future. ISO-NE's external market monitor stated that, "storage is becoming the most economic dispatch technology."[38] The ability for a single battery storage unit to serve multiple functions, such as capacity and regulation, could also improve its economic feasibility, although attempting to capture one value stream may decrease the ability to capture another. BED's evaluation of the economics of storage contained is predicated on this ability to access multiple value streams.

Consistency with BED Goals

When paired with a renewable portfolio or specific intermittent renewable resources, battery storage should be consistent with and supportive of BED's goals. Battery storage has the potential to smooth out intermittent renewable generation curves, making it possible to rely on intermittent renewable resources for a larger portion of BED's power supply needs.

Risk

Unlike a typical generator, a battery storage system has a finite ability to discharge power before it must be recharged. For the 10 MW/40 MWh peaker replacement storage system, its runtime at maximum power would be four hours. If there were a long-duration event, or two back-to-back events requiring peaking capacity, reserves, or emergency back-up, it is possible that a battery storage system would fail to provide the same level of energy output as a fossil-fuel–fired peaker.

Conclusion

Using battery storage as a peaking unit is economically competitive with a fossil-fuel–fired peaker unit. But given the recent clearing prices of the New England FCM, it would not be cost

[38] https://www.iso-ne.com/static-assets/documents/2020/06/npc_2020062324_composite_day1.pdf, accessed July 2020

effective in the near term to install a battery storage system in BED's territory (see additional discussion in Decision Chapter). Declining capital costs and the potential for battery storage to fulfill multiple revenue-producing roles could make battery storage a more cost-effective method than a traditional peaker to meet Burlington's capacity needs and support maintenance of its 100% renewability over time. In addition, where storage can leverage additional value streams such as postponing transmission and distribution upgrades or by providing critical reliability for properties such as the UVM Medical Center or Airport, it could provide additional value to BED's customers. Storage would be evaluated as an alternative or complement to major transmission upgrades if BED were to see significantly increased loads due to electrification.

Combined-Cycle Natural Gas

The late 1990s ushered in a steady shift to natural gas–fired generation in New England. These resources are easier to site, cheaper to build, and generally more efficient to operate than oil-fired, coal-fired, and nuclear power plants. A combined-cycle natural gas facility uses both gas- and steam-powered turbines to produce electricity. The waste heat from the gas turbine is used to generate steam, which then powers the steam turbine. The use of waste heat from the gas turbine increases electricity output without additional fuel use, and therefore increases the efficiency of the facility as compared to simple cycle plants.

Effectiveness

Energy

Combined-cycle natural gas facilities are viewed as strong energy supply resources due in large part to their efficiency from the use of waste heat. They are controllable and dispatchable facilities and can participate in both the day-ahead and real-time wholesale energy markets. While historically natural gas generators operated as intermediate resources, advances in equipment allow them now to operate as baseload generators while maintaining the flexibility to quickly ramp up and down to balance intermittent renewable resources.

Capacity

Combined-cycle natural gas plants are generally excellent capacity supply resources. As non-intermittent generators, these units generally operate at a high capacity factor (85-90%), but their qualified capacity values may still be derated under a marginal reliability impact framework that is being discussed.[39]

[39] https://www.iso-ne.com/static-assets/documents/2023/04/a05f_mc_2023_04_11-13_rca_impact_analysis.pptx, accessed June 2023.

Renewability

The overwhelming majority of natural gas used in energy production in the United States is non-renewable and comes from conventional drilling or hydraulic fracturing ("fracking"). To a much smaller degree, renewable natural gas ("RNG," also known as sustainable natural gas) is available. RNG is a biogas (biomethane) that is purified to a level that it is essentially interchangeable with standard natural gas. Sources of RNG include landfills, wastewater treatment plants, and livestock. While Vermont Gas Systems ("VGS") recently began offering a RNG option to its customers, supplying utility-scale quantities sufficient to meet major power plant demands does not appear feasible at this time. Further, RNG is significantly more expensive than standard natural gas.

Accordingly, the cost analysis below assumes the use of standard, non-renewable natural gas. As such, any natural gas generation, such as electricity sourced by a combined cycle natural gas facility, would not assist BED with meeting its RES requirements.

Environmental Impact

At this point, any combined-cycle natural gas generation purchase would be from an existing resource, but the continued operation of that resource would necessarily involve the continued production of carbon emissions and upstream methane leakage.

Equity and Environmental Justice

The surrounding community of the existing resource would likely be the most impacted by a combined-cycle natural gas plant.

Access

Availability

In 2022, natural gas–powered facilities provided 45% of the energy in the ISO-NE region[40], but only 3% of the proposed resources in the ISO-NE generator interconnection queue are natural gas–fired generators. This indicates that access to new resources may be limited.[41] While there are no natural gas market participant generators in Vermont, given the number of existing facilities in New England, it is likely that BED could have access to a combined-cycle natural gas generator through a PPA. Natural gas is not widely available within Vermont, but Burlington and most residents of Chittenden County are within the VGS service territory and have access to a natural gas pipeline that could power a natural gas generator. In fact, natural gas is already available via pipeline at the McNeil biomass facility.

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[40] https://www.iso-ne.com/about/key-stats/resource-mix/, accessed June 2023.

[41] "2022 Regional Electricity Outlook," page 15, ISO-New England, accessed June 2023.

Ownership

Owning a natural gas generator or acquiring natural gas–fired power through a PPA would be inconsistent with BED's strategic vision. Even if BED did not intend to maintain its 100% renewability status and pursue a NZE strategy, siting a new combined-cycle natural gas generator in Vermont would be challenging. VGS's recent pipeline expansion project faced strong opposition from environmental organizations and residents along the pipeline route, making the prospect of further expansion to supply a power generator highly unlikely.

Cost

Initial Cost

Of the resources summarized above, a combined-cycle natural gas generation facility has the lowest initial cost per kW, at $650-1,300. Despite its low construction costs relative to other resources, combined-cycle natural gas generators have some initial cost risk, due to potential unplanned costs or delays during the project's estimated three-year development process.

Ongoing Cost

The ongoing costs of a combined-cycle natural gas generator are also quite moderate compared to other resource options. The fixed O&M costs are in line with some of the lowest-cost renewable resources, while its variable cost risk profile can be high due to the potential for natural gas prices to spike or to be unavailable due to pipeline constraints in the northeast, particularly in the winter months.

Consistency with BED Goals

As noted above, combined-cycle generators using standard natural gas are non-renewable resources, and as such do not meet BED's renewability requirements.

Risk

The high proportion of natural gas–fired generators in ISO-NE's territory as well as limited pipeline capacity has raised concerns about the availability of natural gas in New England. In its 2020 Regional Electricity Outlook, ISO-NE indicated, "during cold weather, most natural gas is committed to local utilities for residential, commercial, and industrial heating. As a result, we are finding that during severe winter weather, many power plants in New England cannot obtain fuel to generate electricity."[42] Therefore, reliance on a combined-cycle natural gas generator would expose BED to risks of higher fuel costs (spiking natural gas prices, oil prices, or high wholesale energy prices) and higher emissions. Additionally, all the New England states have passed their own renewable portfolio standards that incentivize utilities to increase

[42] "2020 Regional Electricity Outlook," page 11, ISO-New England, accessed June 2023.

or maintain their use of renewable resources. It is likely that potential future increases in renewability targets will make non-renewable resources such as a combined-cycle natural gas generation less desirable over time.

Conclusion

Combined-cycle natural gas plants function as strong energy and supply resources and offer utilities high efficiency and relatively low projected initial and ongoing costs (assuming the fuel is non-renewable natural gas). BED's access to this type of resource is limited by the absence of any combined-cycle natural gas plants in Vermont and the general alignment between population centers and pipeline natural gas availability, which limits suitable areas for siting a generating facility. Additionally, because standard natural gas is non-renewable and RNG is likely challenging from both a supply and cost standpoint at this time, a combined-cycle natural gas facility would not be consistent with BED's renewability goals.

Traditional "Peaker" Unit

Facilities referred to as traditional "peaker" or "peaking" units are fossil fuel–fired simple-cycle generators. The primary fuels used in their operation are oil and natural gas, but other fossil fuels can also be used. Many units can run on multiple fuels to adjust to fuel availability and take advantage of cost differences. Additionally, the potential for these generators to run on biodiesel or RNG may offer other opportunities. For the purposes of this analysis, a 50-240 MW natural gas conventional combustion turbine has been used to determine the benefits and costs and risks of a "peaker" unit.

Resource Effectiveness

Energy

Traditional peaker units are rarely a cost-effective energy supply resource unless the waste heat can be used. The equipment and design of these facilities is not intended for baseload or even intermediate resource operations. Rather, these facilities are intended to operate only during peak hours or as occasional back-up resources. Therefore, because of their limited operation, fixed costs must be recovered over a small number of hours, which drives the levelized price per MWh higher than generators designed for frequent and consistent energy production. The main source of revenue for these units is the capacity and reserve markets, not the energy market.

Capacity

Peaker units are designed and constructed to serve as capacity resources. Thus, BED could, by constructing a peaking unit, likely meet whatever capacity need it had at the lowest initial cost.

Renewability

Peakers are primarily fossil fuel-fired powered units and therefore they are not generally renewable resources. As noted above, RNG is now available in Vermont, but not in a quantity or at a cost that would make utility-scale use feasible.[43] The cost analysis below assumes the use of standard, non-renewable natural gas. Unless fueled by RNG, a peaker unit would not assist BED with meeting its Tier 1 RES requirement. If such a unit were fueled by RNG, the energy price would be high enough that the unit would not run often and thus would be a relatively high-cost, low-contribution Tier 1 resource.

Environmental Impact

At this point, any electric generation by a traditional "peaker" unit would be from of an existing resource, but the continued operation of that resource would necessarily involve the continued production of carbon emissions.

Equity and Environmental Justice

The surrounding community of the existing resource would likely be the most impacted by a traditional "peaker" unit. Some communities are actively engaged in reducing the harm to their communities from existing plants.[44] Additionally, the possibility of replacing peakers with energy storage is a possibility.[45]

Access

Availability

BED currently owns a 25 MW peaker generator, the Burlington GT,[46] which is located on the waterfront in the City of Burlington. Due to its infrequent operation and modest size compared to other generating resources, siting a peaker unit is generally not as challenging as other types of resources. In addition to the GT, peaker units are located throughout Vermont and the ISO-NE region. For these reasons, BED views a peaker generator as reasonably available.

Ownership

Multiple "peaker" units are located in Vermont; all of the peaker units within Vermont serve as important capacity resources for the utilities that own them. BED is not presently aware of any plans by any Vermont utilities to sell existing peaker units in the State. Therefore, BED's ownership of another peaker unit would likely be tied to the construction

[43] Although the use of RNG for a peaker, due to the relatively low energy production, would result in less increased costs than for use of RNG a combined cycle plant.
[44] https://www.salemnews.com/news/light-commissioner-steps-down-over-activists-push-to-stop-peaker-plant/article_be8ad72a-8865-11ed-9824-e7caf14b8944.html, Accessed July 2023
[45] https://www.cleanegroup.org/publication/fossil-fuel-end-game/, Accessed July 2023
[46] The Burlington Gas Turbine can currently only use oil fuel.

of a new facility in Burlington or a contract with an existing facility outside Vermont. The most recent peaker unit built in Vermont was a facility in Swanton, constructed by VPPSA in 2008.

Cost

Initial Cost

Compared to the other resource alternatives reviewed, a peaker unit has a relatively low initial cost on a per kW basis. At $700-1150 per kW, only the larger combined cycle natural gas generator has an equally low range of capital cost per kW as a peaker unit. The comparatively low costs and smaller size of peakers suggest a relatively low capital cost risk related to project length or delay.

Ongoing Cost

The fixed O&M costs for a peaker are the lowest among the resources reviewed while the variable O&M costs are relatively high. Because capital costs must be recovered over a small number of generation hours, the levelized energy costs of a peaker are quite high and are by the far the highest among the non-renewable resources considered. A peaker, however, is not intended to serve as a primary energy supply resource. Rather, the ongoing economics of a peaker are tied to whether its costs of operation and maintenance are less than the cost to purchase market capacity or capacity from another resource, which, if initial costs are ignored, they generally are.

Consistency with BED Goals

As a fossil-fuel–powered generator, a peaker is not consistent with BED's renewability goals. However, unlike baseload or intermediate non-renewable resources that produce significant amounts of energy, the magnitude of non-renewable energy generated by a peaker is quite small. The potential exists to use RNG for peaking purposes, or the output from a peaker could be "greened" using replacement or excess RECs (or other emission offset tools) equal to the unit's annual MWh output, as is currently done with BED's GT.

Risk

Because peakers derive their financial value from the capacity and reserve markets and do not generally generate revenue from energy production, their economics are vulnerable to clearing prices of market auctions each year. A low clearing price could dramatically reduce revenue for a peaker for an entire year with little opportunity or ability for a utility to improve it. Historically, there have been extended periods in which the capacity market revenues would not support peaking generation or in which capacity value was zero, although revisions to FCM structure should moderate price swings through demand curves and reward peakers' quick availability through pay-for-performance.

Conclusion

Peakers are intended to serve a narrow yet important primary function: the provision of capacity supply to a utility and the grid. In terms of this specific function, peakers are highly efficient and cost-effective. As expected, when compared to resources intended to serve as energy-producers, they do not appear economically attractive for acquiring energy. The current low-capacity market prices have made BED's acquisition of additional traditional peaking capacity unlikely in the near term.

Long-Term Renewable Contract (Non-wind)

This analysis evaluates the merits of a long-term renewable resource contract with a generic utility-scale hydroelectric generator (over 5 MW).

Effectiveness

Energy

Run-of-the-river hydro is an intermittent, uncontrollable resource. BED can minimize its risk of receiving an undetermined quantity of energy by choosing to contract for either a firm or unit-contingent PPA with a hydro generator. Additionally, hydro units with storage capability can be excellent providers of capacity under present market rules due to their ability to move the output to different times of the day.

Capacity

Hydro contracts can be crafted to include capacity in addition to energy. Like other intermittent resources, however, run-of-the-river hydro is not a strong capacity resource, while hydro with ponding can be.

Renewability

Run-of-the-river hydro is a Tier 1 renewable resource. Additionally, depending on the hydro resource, the unit(s) could produce higher value RECs that can be sold by BED (as is the case with the Winooski One facility).

Environmental Impact

The environmental impact of a long-term renewable contract would depend on the exact nature of the resource. Environmental impacts could be mitigated by pursuing contracts with LIHI-qualified plants.

Equity and Environmental Justice

The equity and environmental justice impact of a long-term renewable contract would depend on the particular resource.

Access

Availability

There are many existing hydroelectric generators of varying sizes and classes throughout Vermont and the ISO-NE region. BED has entered contracts for hydropower in the past and believes hydro contracts should continue to be available as a supply resource.

Ownership

BED evaluated contract options for additional hydro in this analysis. It did not evaluate additional hydro ownership options.

Cost

Initial Cost

Under a contract, BED would not be responsible for initial capital costs. Nonetheless, new hydro construction has high initial costs and risks that are frequently reflected in contract terms due to their magnitude.

Ongoing Cost

For the purposes of this analysis, BED assumes the contract price for hydro energy would reflect market costs.

Consistency with BED Goals

From a renewability standpoint, a contract for existing hydro energy is consistent with BED's goals. If the unit is within close proximity to Burlington or within Vermont, such a contract could also be consistent with BED's desire to increase its reliance on local resources.

Risk

Because this resource analysis is limited to additional PPAs for hydropower, it is possible to avoid some of the normal renewable resource intermittency issues by entering into a firm delivery contract. Nonetheless, even with a firm contract, some risk of non-performance remains, which would expose BED to wholesale market energy prices. A defaulting counterparty would be liable for liquidated damages intended to make BED whole (covering any resulting increased energy costs), but there is a risk that a counterparty would not be in a financial position to pay the liquidated damages.

Conclusion

A contract for hydro could allow BED to efficiently match its energy supply resources to its needs. Hydro, especially ponded hydro, can also provide capacity supply, although it is quite minimal relative to the energy supplied in run-of-the-river units. In addition, BED's recent hydro purchases have involved multiple assets delivering under one contract. The energy purchased through an additional hydro contract, provided it includes the related RECs, would qualify under Tier 1. Given the number of hydro units throughout Vermont and the ISO-NE area, BED believes hydro is a resource with ample availability. Assuming contract prices are similar to the wholesale cost of energy, a contract for hydropower would be cost-competitive with other renewable supply options.

Long-Term Non-Renewable Contract

This analysis evaluates the merits of a long-term contract with a nuclear facility.

Resource Effectiveness

Energy

Nuclear generators provide consistent, baseload energy and are regarded as strong energy producers with a capacity factor in the 80-90% range. Nuclear generators in New England are not well-suited to provide the fast start and flexible output to balance supply changes related to intermittent resources.

Capacity

Due to their reliable nature and consistent output, nuclear generators are strong capacity supply resources.

Renewability

While a nuclear generator does not produce measurable air emissions, its use of non-renewable uranium classifies it as non-renewable resource. If BED wished to retain its 100% renewability, it would need to purchase RECs to cover the purchased non-renewable energy.

Environmental Impact

The environmental impact of a long-term non-renewable contract for nuclear power would depend on the resource.

Equity and Environmental Justice

Likewise, the equity and environmental justice impact of long-term non-renewable contract for nuclear power would depend on the resource.

Access

Availability

The number of nuclear generators in the ISO-NE region and the share of regional energy supplied is expected to continue to decline.

Ownership

This option is intended to consider a contract for energy, not resource ownership because of BED's plans to maintain its 100% renewable status.

Cost

Initial Cost

Under a contract, BED would not be responsible for initial capital costs. Nonetheless, nuclear has high initial costs and risks which are frequently reflected in contract terms due to their magnitude.

Ongoing Cost

Like long-term renewable options, it is likely that BED's costs would be based on market prices rather than a unit's specific economics.

Consistency with BED Goals

Due to its non-renewable classification, nuclear power is not consistent with BED's 100% renewability.

Risk

If natural gas prices remain at historically low levels, natural gas generators are expected to continue to out compete nuclear generators in the wholesale energy markets.[47] Thus, nuclear power would expose BED to additional cost risks that could result in upward rate pressure.

Conclusion

As more economically feasible natural gas generation and wind resources are on the rise in the ISO-NE region, nuclear power is on the decline, as two major plants were retired in recent years. While BED could benefit from having access to additional consistent energy and capacity supply, such supply from a nuclear facility would be inconsistent with BED's 100% renewability.

Overall Conclusion

BED currently has enough energy supply to reliably serve its customers in accordance with 30 V.S.A. § 218c. Indeed, BED maintains ownership and/or control over resources that can supply all its energy requirements through 2024. However, because 100% of BED's energy comes from renewable resources, BED is substantially short on capacity. This shortfall or capacity gap is a function of ISO-NE's reliability protocols, which significantly de-rate resources that are intermittent, such as wind, solar (if ISO-NE recognized), and run-of-river hydro dams.

BED is highly dependent on the continued operation of the McNeil biomass plant to maintain BED's status as a 100% renewably sourced energy provider. However, the economic viability of the McNeil plant has faced challenges in recent years with the fall in wholesale market energy prices, and the loss of CT 1 qualification for half of its RECs will be an additional economic challenge. Furthermore, the plant will need continued capital investments to maintain its

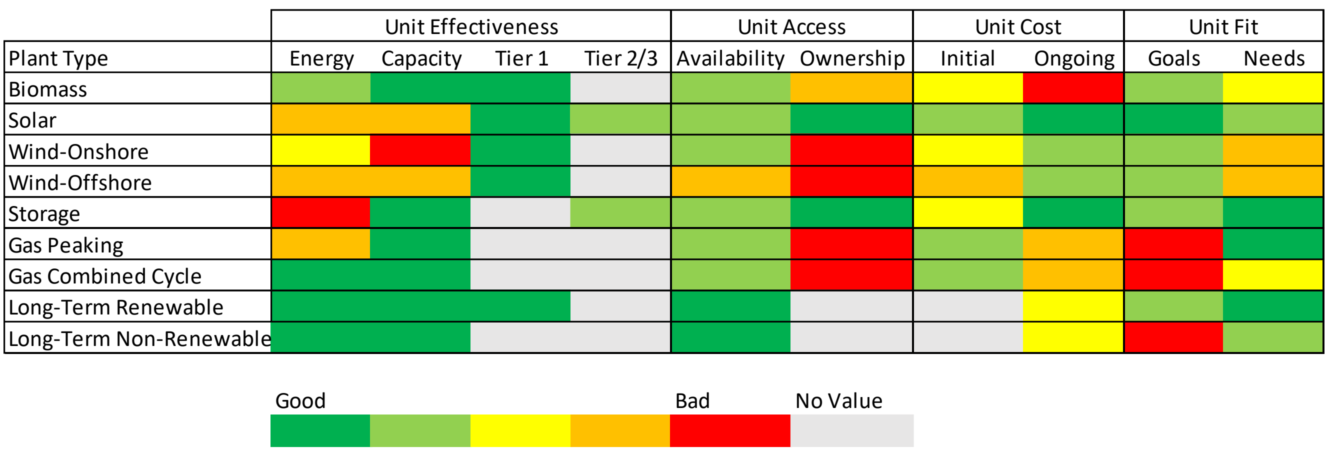
[47] "2020 Regional Electricity Outlook," page 9, ISO-New England, accessed June 2023.

reliability. If McNeil were to be retired, BED would need to acquire cost-effective replacement energy and capacity, which may not be readily available in the short term.

To summarize the costs and benefits of various resources, BED performed a comparative analysis, shown in Figure 2-15 below. Those resources with green-shaded boxes have been identified as creating the most benefits in terms of their effectiveness, accessibility, and costs.

Unit effectiveness is shown as a function of capacity factor for energy, market capacity received for the resource as a percentage of the facility's nameplate capacity for capacity, and whether the resource is eligible for each of the RES tiers under the Tier 1 and Tier 2/3 columns. Unit access is shown based on this chapter's analysis regarding availability and ownership. Unit cost is based on the initial and ongoing costs assumed in each analysis on a per kW basis. Unit fit is based on the description of how the resource would or would not meet BED's needs and goals.

Figure 2-15: Resource Comparisons



3. Transmission & Distribution

BED continues to recognize the shift in the fundamental aspects of power supply and delivery. The one-way energy flow from large-scale generation via high-voltage transmission lines to local distribution systems that has dominated grid structure for decades grows increasingly bi-directional and dynamic each year. With the growth of distributed generation and net metering, the traditional customer role as an energy user is expanding to include being an energy generator and potentially a supplier of other ancillary grid services. Just as the customer role is evolving, so too must utilities and their transmission and distribution systems.

This chapter describes BED's efforts to provide reliable transmission and distribution services as well as future projects that will ensure BED is prepared for the challenges and opportunities of grid modernization.

System Overview

BED is connected to Green Mountain Power ("GMP") through the 34.5 kV bus tie breaker at the McNeil Plant Substation and to the rest of Vermont through Vermont Electric Power Company ("VELCO") at the East Avenue and Queen City Substations. The East Avenue 13.8 kV switchgear is supplied by VELCO's 115/13.8 kV T1 transformers rated 30/40/50 and T2 transformer rated 30/40/56 MVA. The Queen City 13.8 kV switchgear is supplied by a VELCO 115/13.8 kV, 33.6/44.8/56 MVA transformer. The McNeil 13.8 kV switchgear is supplied by a BED 34.5/13.8 kV, 20/26.7/33.3 MVA transformer. The VELCO transmission system connects all of the utilities in Vermont to each other and also has interconnections with New York, Quebec, Massachusetts, and New Hampshire.

BED's sub-transmission system includes approximately 1.5 miles of 34.5 kV line from the East Avenue Substation to the McNeil Plant Substation. This line is jointly owned between BED (40 MVA) and GMP (20 MVA). The line is connected to the VELCO transmission grid at the East Avenue Substation by VELCO's 115/34.5 kV, 33.6/44.8/56 MVA transformer and to GMP's 34.5 kV system by the 34.5 kV tie bus breaker at the McNeil Plant Substation.

BED's distribution system throughout the City is comprised of sixteen 13.8 kV circuits with approximately 132 miles of 13.8 kV lines distribution taps. BED also owns the 0.8-mile 12.47 kV distribution circuit that serves the Airport. The distribution system is approximately 47% underground and 53% aerial.

BED has 25 MW of on-system generation at the Burlington Gas Turbine and 7.4 MW at the Winooski One Hydro Plant that are connected to the 13.8 kV system. BED also operates, and is 50% owner of, the McNeil Generating Station. McNeil is on the GMP system but is connected to the BED system through the GMP 34.5 kV bus at the McNeil Plant Substation.

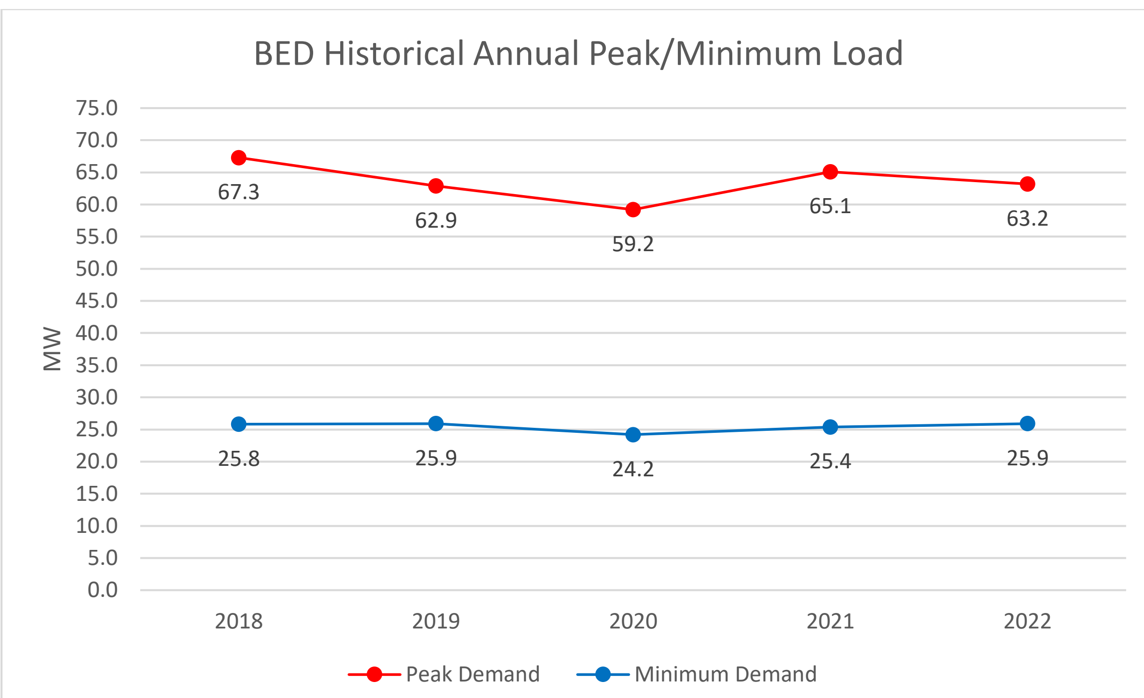
BED's distribution system annual peak load for year 2022 was 63.21 MW. The substation transformer and generator ratings and coincident peak demands are provided in Table 3-1 below:

Table 3-1: Substation Transformer and Generator Ratings and Coincident Peak Demands

	Rating	**Peak Load**
East Avenue Bus #3 T1 Transformer	50 MW	14.00 MW
East Avenue Bus #4 T2 Transformer	56 MW	9.41 MW
Queen City Transformer	56 MW	22.18 MW
McNeil Transformer	33.3 MW	16.24 MW
Burlington International Airport	-	1.01 MW
	Rating	**Peak Generation**
Lake Street Gas Turbine	24.8 MW	0.00 MW
Winooski 1 Hydro	7.2 MW	0.37 MW

Figure 3-1 shows BED's historical annual peak and minimum demand.

Figure 3-1: BED Historical Annual Peak/Minimum Load



Planning & Standards

BED's distribution system is operated as an open primary network. This is a system of interconnected primary circuits with normally open switches at the interconnection points. When problems arise on the circuit, back-up is provided to as many customers as possible by other circuits by changing the normally open and closed points on the system. Switching is performed by BED's Supervisory Control and Data Acquisition (SCADA) system or by manual switching when necessary.

The East Avenue, Queen City, and McNeil Substation transformers' load tap changers (LTCs) are set to hold voltage at the peak hour between 122.1V and 124.6V (set point of 123.4V and bandwidth of 2.5V on a 120V basis) at the substation 13.8 kV bus. The voltage delivered to BED's customers meets ANSI C84.1-2011 Range A during normal operation and ANSI Standard C84.1-2011 Range B during contingencies. The substation transformer LTC voltage settings allow for ISO-NE Operating Procedure No. 13 (ISO OP-13) Standards for 5% voltage reduction, primary voltage drop, and 6 volts of secondary voltage drop (distribution transformer, secondary cable and service wire).

Most of BED's trunk lines are rated 600 amps. This is to allow for the switching of loads between circuits, even at the system peak. The loading on the 600 amps main trunk lines is typically kept below 9 MVA during normal operation to allow for the isolation of a fault to a small section of a circuit and switching the remaining sections to adjacent circuits.

The power factor is measured and monitored by SCADA at the substation breakers for the substation transformer and each circuit, and at reclosers and switches along the circuits. BED maintains a 0.98 power factor or higher on its distribution circuits to comply with VELCO power factor requirements and to keep the circuit voltage from dropping below an acceptable level during normal conditions and contingencies. This is implemented by switched and fixed capacitor banks and close monitoring of the volts-amps reactive ("VAR") load on each circuit.

BED standard wire sizes are as follow:

- Aerial Primary Circuits: 1/0 Aluminum, 4/0 Aluminum, 336 kcmil AAC and 556 kcmil AAC;
- Aerial Secondary Circuits: #2 Aluminum, 1/0 Aluminum, 4/0 Aluminum and 336 kcmil AAC.
- Underground Primary Circuits: 1/0 Aluminum, 350 kcmil Copper, and 1,000 kcmil Copper;
- Underground Secondary Circuits: #2 Aluminum, 1/0 Aluminum, 2/0 Aluminum, 4/0 Aluminum, 350 kcmil Aluminum, and 500 kcmil Aluminum.

BED standard transformer sizes are as follow:

- Pole-mounted transformers: 15 kVA, 25 kVA, 37.5 kVA, 50 kVA, 75 kVA, 100 kVA, and 167 kVA;
- Pad-mounted single phase transformers: 15 kVA, 25 kVA, 37.5 kVA, 50 kVA, 75 kVA, 100 kVA, and 167 kVA
- Pad-mounted three phase transformers: 75 kVA, 112.5 kVA, 150 kVA, 225 kVA, 300 kVA, 500 kVA, 750 kVA, 1,000 kVA, and 1,500 kVA;
- Submersible transformers: 15 kVA, 25 kVA, 37.5 kVA, 50 kVA, 75 kVA, 100 kVA, 167 kVA, 250 kVA and 333 kVA;

Distribution system planning studies are performed to improve system efficiencies and identify the least-cost options to meet future load requirements in a safe and reliable manner. Distribution system planning is performed consistent with the Distributed Utility Planning principles and planning process under Vermont Public Utility Commission Docket #7081. In addition to resources such as energy efficiency and distributed generation, BED will also be looking at the potential use of battery storage to avoid future T&D upgrades. Distribution system studies are performed when the system peak load forecast, actual system peak, or an individual circuit experiences significant load change. This includes continued study of the NZE future scenario, discussed in the NZE chapter. In 2022, BED performed a planning study to evaluate the ability of BED's distribution system to serve a future district energy electric boiler and the downtown CityPlace project load additions.

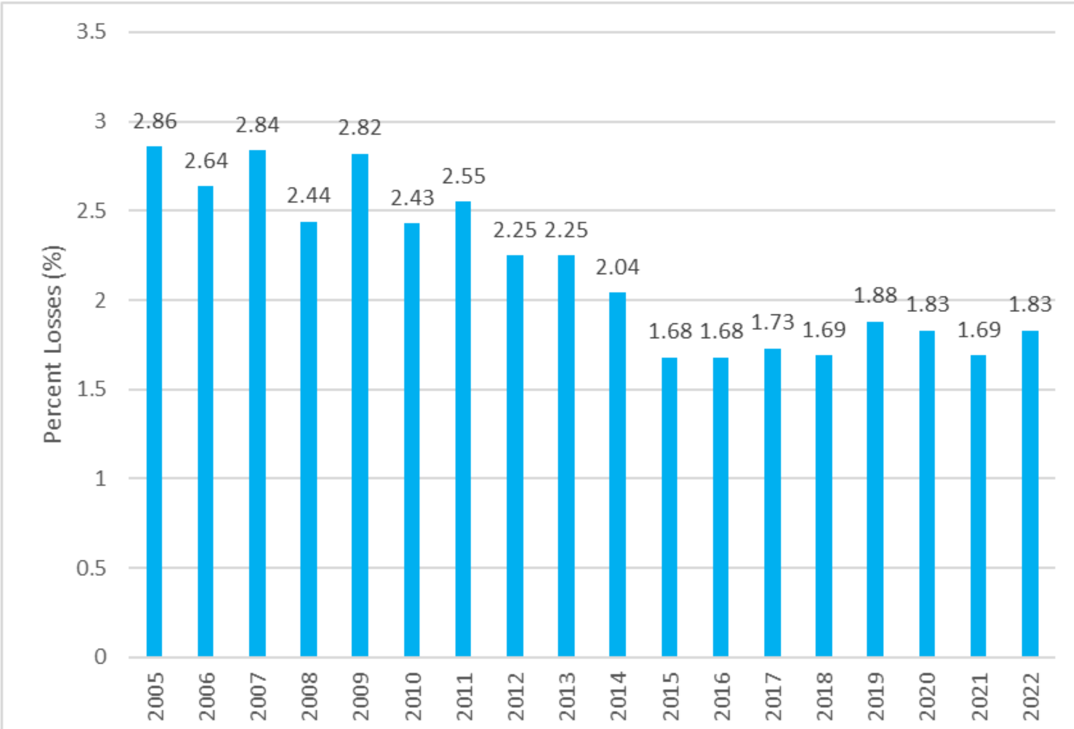
BED performs feasibility and system impact studies to identify the impact of proposed distributed generation on the distribution circuits. The impact studies evaluate the impact of distributed generation on the distribution system at BED's peak load hour and also during light load condition and maximum generations under normal system configuration and contingencies.

BED uses CYMDIST software for distribution system analysis, efficiency studies, impact studies, and planning studies. The distribution system simulation model is presently updated manually with efficiency gains from CYME Gateway software to convert data from a geographical information system ("GIS") to CYMDIST model.

System Efficiency Measures

The movement of power through the distribution system incurs electrical losses due to the resistance of the equipment to the flow of electricity. System losses increase the amount of electricity required to supply the customers' needs. BED has several programs in place and routinely performs analysis to improve system efficiency using methods that are both cost-effective and technically feasible. As a result of BED's system efficiency efforts, BED's total distribution system losses have been maintained between 1.68% and 1.88% over the last eight years. Figure 3-2 shows BED's historical distribution system losses.

Figure 3-2: System Losses



Distribution system efficiency measures are evaluated on each circuit and cost-effective measures are implemented. The following efficiency measures are evaluated by BED:

- Optimal locations of capacitor banks
- Distribution system configuratio
- Phase balancin
- Single-phase to three-phase conversio
- Increasing distribution voltage leve
- Creating new 13.8 kV distribution circuit
- Re-conductoring of lines with lower loss conductors
- Equipment acquisition procedure
- Transformer/load matching

Optimal Locations of Capacitor Banks

Capacitor banks are installed on BED's distribution circuits to reduce the VAR flows, reduce losses, and improve voltage. BED maintains a 0.98 power factor or higher on its distribution

circuits to comply with the VELCO power factor requirements, reduce losses, improve voltage, and be able to serve load with acceptable voltage during contingencies.
Fixed or switched capacitor banks are installed on the distribution circuits. The switched capacitor banks are controlled through the SCADA system, and a few in the field are controlled via stand-alone voltage or VAR controllers. BED's system operators remotely open and close capacitor banks based on the voltage requirements or circuit breaker preset VAR alarm values to maintain a circuit power factor close to unity.

The optimal locations of existing and new capacitor banks on each circuit are determined using CYMDIST software to minimize losses or improve voltage.

In 2023, BED performed a capacitor bank study to determine the optimal locations for the existing capacitor banks on its distribution circuit. The results of this study showed that the relocation of the existing capacitor banks to new optimal locations is not cost effective in a 25-year societal-cost analysis (BED depreciates its distribution capacitor banks on a straight-line basis over a 25-year service life).

Distribution Circuit Configuration

Distribution system configurations are evaluated when BED's system peak or an individual circuit experience significant load change. In year 2022, BED evaluated balancing the load between 1L1 and 1L4 as well as 3L3 and 3L5 circuits to optimize losses and improve reliability. The results of this study show that balancing load between the circuit groupings above reduces system peak losses by 25.89 kW and is cost-effective in a 33-year societal-cost analysis (BED depreciates its distribution cables on a straight-line basis over a 33-year service life). The first re-configuration case is planned to be implemented in FY24. The second re-configuration case has other operational implications that require further system analysis (impact to BED's UFLS operating requirements) before the load can be moved between circuits. This analysis is planned to be completed in FY24 and, if the project can move forward, will be implemented in FY25.

Phase Balancing

Balancing the phase loading on the distribution circuits will decrease line losses and improve line voltages and backup capability. On an annual basis, BED evaluates the loads among the phases at summer peak on each circuit and corrective actions are taken and implemented based on the results of this evaluation. BED evaluates the phase balancing at the substation switchgear breakers for each distribution circuit and going forward at the reclosers and switches located on the distribution circuits.

With BED's distribution system losses of approximately 1.83%, balancing the phases on the distribution circuits is typically done to improve the voltage for normal system operation and during contingencies.

In 2022, BED evaluated the balancing of phases on its distribution system to optimize losses and improve line voltages and backup capability. The results of this study show that transferring load at locations on the 1L4 circuit reduces system peak losses by 2.49 kW and is cost-effective in a 33-year societal-cost analysis (BED depreciates its distribution cables on a straight-line basis over a 33-year service life). This phase balancing is scheduled to be implemented in FY2025.

Single-Phase to Three-Phase Conversion

Single-phase to three-phase conversions are evaluated when BED's system peak or an individual circuit experience significant load change. Upgrading a line from single-phase to three-phase construction results in line loss reduction. However, the conversion of BED's circuits from single-phase to three-phase construction has not been cost-effective because the potential loss savings from this conversion is low (losses on BED's distribution system is approximately 1.83%) vs. the high cost of rebuilding BED's aerial and underground circuits. Traffic control may be required during the construction of aerial projects. The cost of placing BED's lines underground within a paved portion of a City street includes a City Administrative and Excavation fee of approximately $26 per square foot.
In 2022, BED evaluated upgrading a region of its distribution circuit sections from two-phases to three-phase construction. The results of this study showed that upgrading this section of BED's lines on Ethan Allen Parkway, part of the 1L4 circuit, from two-phase to three-phase construction reduces system peak losses by 28.84kW but is not cost-effective in a 33-year societal-cost analysis (BED depreciates its distribution cables on a straight-line basis over a 33-year service life). This upgrade will not be implemented for its efficiency benefits alone but is planned to be constructed in FY24 for system reliability to be able to serve 80 MW of system peak load.

Increasing Distribution Voltage Level

As of year 2023, approximately 200 feet of 4.16 kV distribution remained in the city and is fed from a stepdown distribution transformer. The 4.16 kV tap is located on Pearl Street and feeds one customer. BED has been working closely with its customers to complete the conversion of all taps to 13.8 kV. This remaining conversion is contingent on BED obtaining easements from private property owners.

Creating New 13.8 kV Distribution Circuits

The idea behind constructing additional 13.8 kV circuits is to reduce line losses by reducing the load on an existing feeder. In general, creating new circuits on BED's system solely to lower line losses is not cost-effective because BED's distribution losses are low (approximately 1.83%), the main trunk lines have large size wires, and the cost associated with installing aerial and underground circuits is very high.

Re-Conductoring of Lines with Lower Loss Conductors

Upgrading the conductor size of a circuit will result in a lower line resistance and lowering the line resistance will reduce line losses. BED's trunk lines are oversized because BED's distribution system is designed to allow for the isolation of a fault to a small section of a circuit and switching the remaining sections of the circuit to alternate feeds.

In 2022, BED evaluated upgrading the conductor size on sections of its distribution circuits to larger size conductors. The results of this study showed that reconductoring existing lines was not cost-effective in a 33-year societal-cost analysis.

Equipment Selection & Utilization

BED uses least-cost principles to select transformers and cables. The specific processes used for transformer and cable acquisitions are outlined below. Other major equipment such as aerial wires, breakers, reclosers, switches, and capacitors are purchased per BED standards, specifications, and purchasing process.

a) <u>Transformer Acquisition Procedure</u>
   BED requests quotations for steel metal core and amorphous metal core distribution transformers. BED uses a distribution transformer acquisition program to make purchase decisions based on societal-cost analysis per the Memorandum of Understanding between the Public Service Department and BED dated December 27, 2004. The analysis considers the initial cost of the transformer, and the economic value of the increase in capacity costs, energy costs, VELCO transmission costs, distribution costs, and environmental externalities over 25 years (BED depreciates its distribution transformers on a straight-line basis over a 25-year service life). The least societal cost transformers are purchased.

b) <u>Cable Acquisition Procedure</u>
   BED uses a cable acquisition program to make purchase decisions based on 33-year societal-cost analysis. The analysis considers the initial cost of the cable and the economic value of the increase in capacity costs, energy costs, VELCO transmission costs, and environmental externalities over 33 years (BED depreciates its cables on a straight-line basis over a 33-year service life).

Transformer/Load Matching

New or replacement transformers installed on BED's system are purchased using BED’s transformer acquisition procedure and sized to match customer load. For new transformers, BED sizes the transformers based on coincident peak load estimates from the customer, engineer or electrician, similar facilities’ loads in the City, and our engineering judgment. When BED replaces an existing transformer, a load study is first done to determine the correct size for the replacement transformer. The residential transformers are not sized to allow every customer connected to the transformer to add an electric vehicle, heat pump, or other strategic electrification loads. Depending on the total magnitude of the additional load, the transformer may need to be replaced. By correctly matching the size of the transformer to the load being served and existing distributed generation while also allowing for a margin of growth, transformer losses are reduced, which improves the overall system efficiency.

BED’s Advanced Metering Infrastructure (“AMI”) system provides BED with information on energy, demand, reactive power, or power factor for each customer. This information is stored in the meter data management system (MDMS). BED completed Phase 1 of its new MDMS implementation in FY23, converting its MDMS to a new platform. Phase 2 of the MDMS project entails the addition of grid analytics tools including Transformer Loading and Line Loss Analysis modules.

BED has implemented a “Transformer and Service Point Auto Updater” feature in ArcGIS to integrate customer information with the transformer connecting that customer. This information is stored in the GIS. This information improves staff efficiency by reducing manual processes. This enables staff to readily create load reports on existing transformers and size future transformers. The GIS system can allow for easy export of connected services to a single transformer. From this list, the AMI interval data can be queried from the MDMS and dropped into a reporting tool that analyzes the data. Figure 3-3 below is a sample of those reports that are generated out of this process. The Transformer Loading tool to be implemented in MDMS Phase 2 will use the integrated GIS data to automatically create transformer load reports on demand without a manual data collection process in the middle. The project implementation is on track to start in FY24.

Figure 3-3: Sample Transformer Load Report

Transformer Loading Report (#4968)

User Input

Transformer Information:

Facility ID#	*4968*	Secondary Phases	*1Ø*
Rating (kVA)	*50*	Secondary Voltage	*120/240*
Impedence (%)	*2.1%*	Type	*OH*
Installed Date	*6/12/1984*	Manufactured Date	*1983*
		# of Non-AMI Meters	*0*

Transformer Load Data:

Data Range: 8/1/2020 – 8/1/2023

Meter 'Location IDs'

465	37956	48213	8067	19062
11157	35877	40191	35442	46587
35235				

Non-Ami

**Loading for non-AMI meters estimated by average of AMI meters every 15-min interval*

Coincidental Peak (kVA): 41.6

Coincident Peak (Timestamp): 02/13/2021 17:00

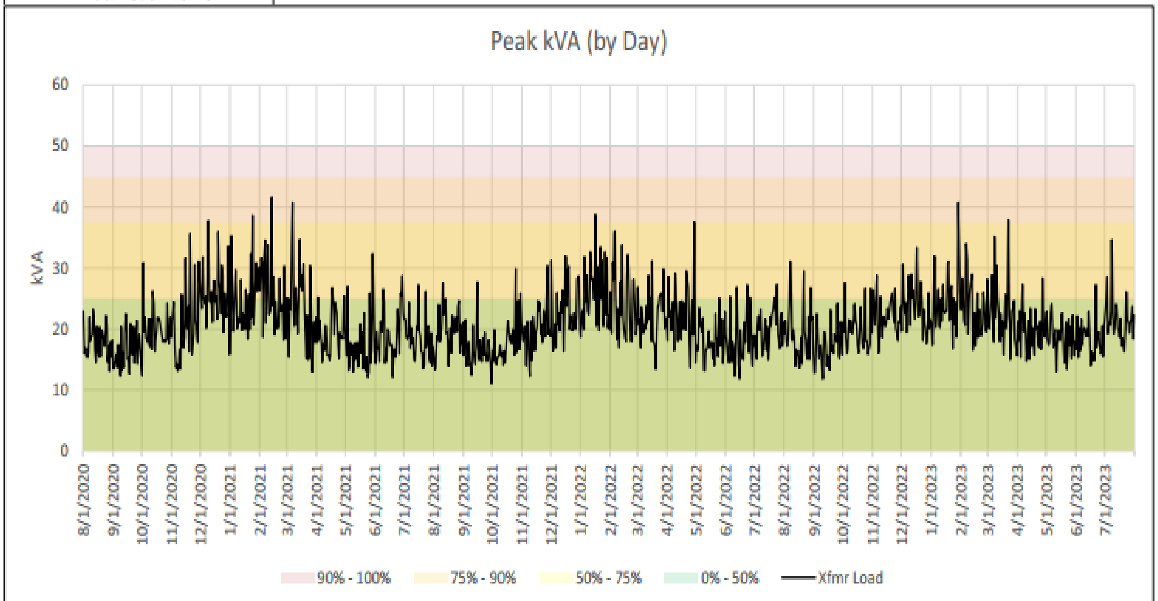
Non-Coincidental Peak (kVA)*: 122.2

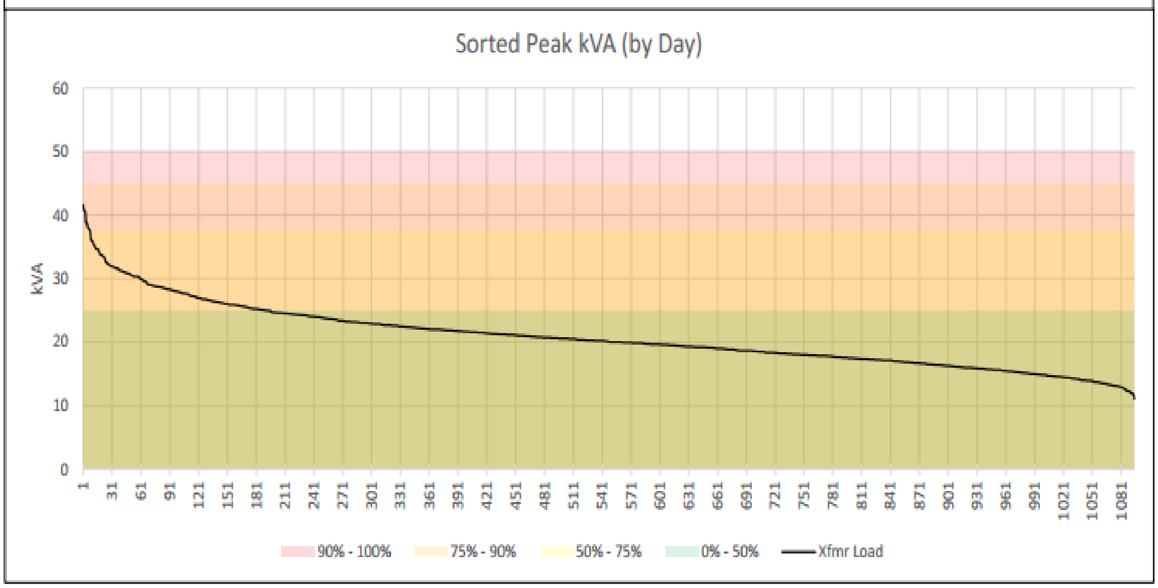
**Sum of individual customer peak loads.*

Loading Percents:

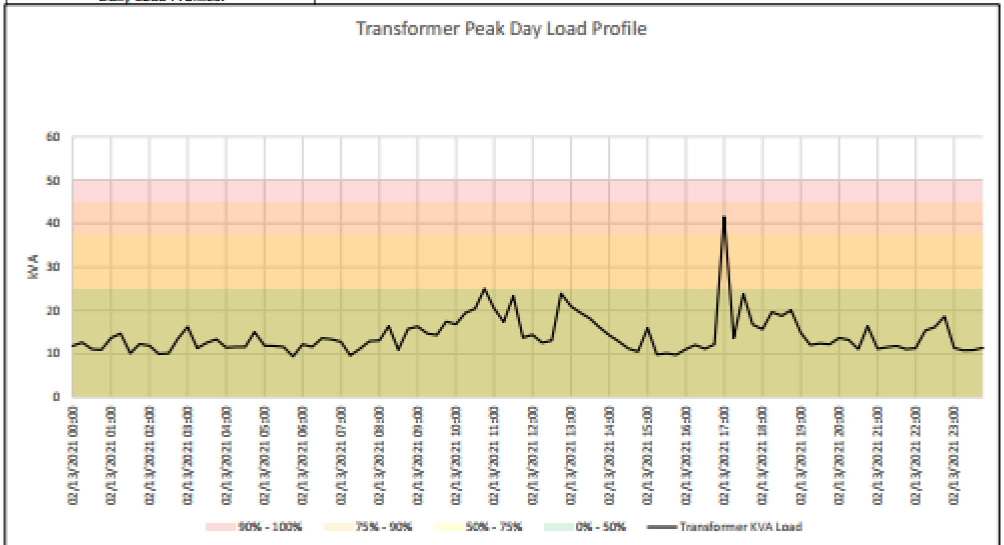
Percent Loading	Hours at Load Level	
> 100%	0	0%
90% - 100%	0	0%
75% - 90%	2	0%
50% - 75%	62	0%
0% - 50%	26435.25	100%

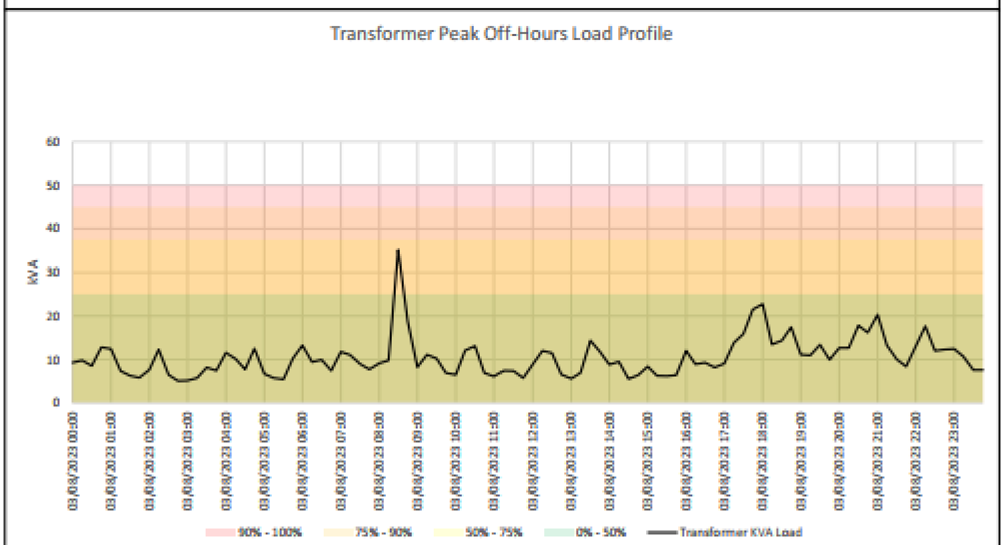
Annual Load Profile:

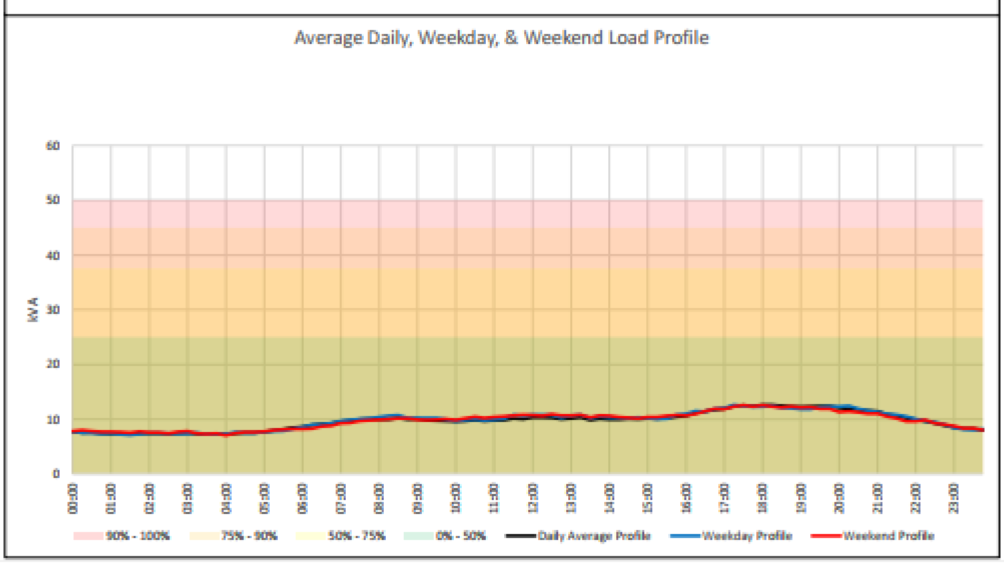




Daily Load Profiles:







Reliability

BED is committed to supplying the highest system reliability and power quality to its customers that is economically feasible. BED designs its distribution grid to withstand all N-1 contingency scenarios at the feeder level. This means for the loss of any feeder breaker, BED has one, if not two, contingency plans in place to backfeed all of the load on that feeder from either an adjacent feeder or a feeder from another substation. By coordinating all the possible backfeed scenarios, the BED distribution grid is designed to withstand the loss of one of its three substations. Each feeder out of any given substation has a contingency plan in place so that all feeders could be backfed from the other two substations simultaneously, supporting all of the system load during the loss of a single substation.

Outside of our planning criteria, like other utilities, BED tracks power interruptions or outages. An interruption of power is considered an "outage" if it is a zero-voltage event exceeding five minutes. There are two types of outages: planned outages and unplanned outages. Planned outages are outages that are initiated and scheduled in advance by BED for purposes of construction, preventative maintenance, or repair. Unplanned outages are outages due to unexpected and unscheduled events. BED's distribution system reliability is measured by the System Average Interruption Frequency Index ("SAIFI") and Customer Average Interruption Duration Index ("CAIDI") pursuant to PUC Rule 4.900. These indices are also impacted by BED's planned outages and include major storms.

Every year, BED analyzes the outage information on its distribution circuits, identifies the worst performing distribution circuits, and updates its action plan to improve the performance on these circuits.

BED's SAIFI for 2022 was 1.06 interruptions per customer, significantly better than the SAIFI Service Quality and Reliability target performance of 2.1 interruptions per customer. BED's CAIDI for 2022 was 0.67 hours, well under the CAIDI target performance of 1.2 hours.

Figure 3-4 shows BED's historical SAIFI values.

Figure 3-4: BED Historical SAIFI Values

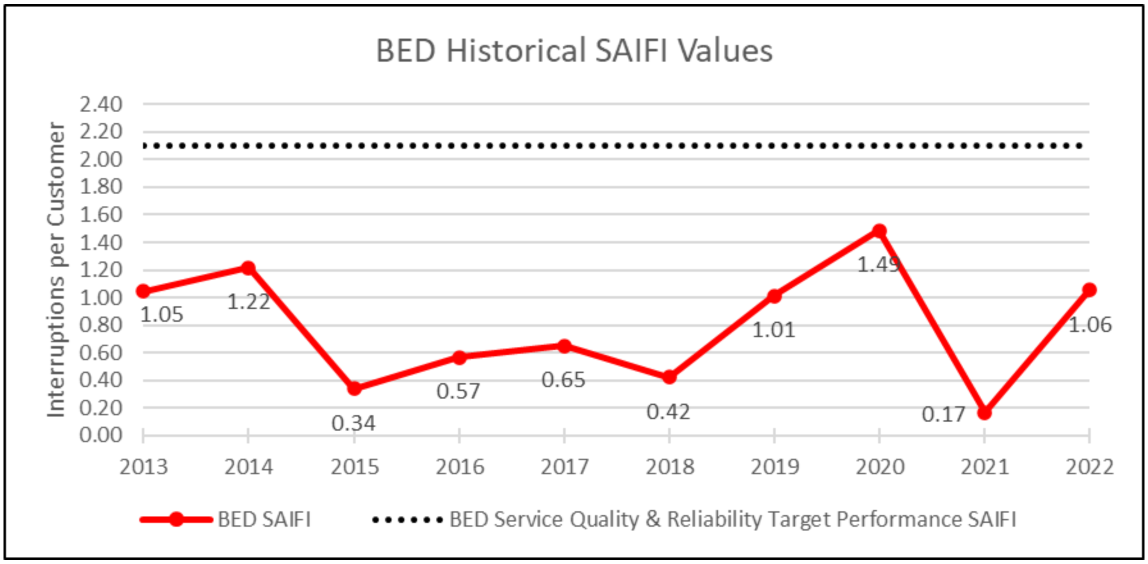
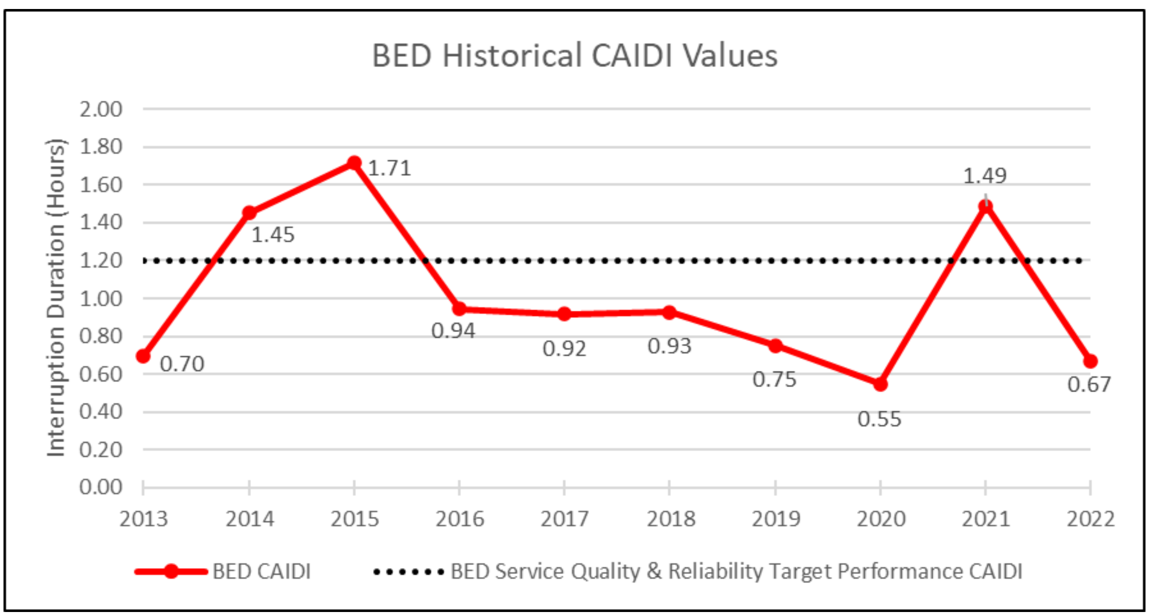


Figure 3-5 shows BED's historical CAIDI values.

Figure 3-5: BED Historical CAIDI Values



Reliability Improvement Programs

BED's distribution system is designed to allow for the isolation of a fault to a small section of a circuit and switching the remaining sections of the circuit to alternate feeds prior to making repairs. In addition, BED has several programs in place to ensure that system reliability and power quality remain as high as possible. The following are a few of these programs that are discussed below:

- Distribution System Operating Procedures
- Distribution System Protection
- Wildlife Protectors
- Pole Inspection and Maintenance Plan
- Overhead Distribution Inspection and Maintenance Plan
- Underground Distribution Inspection and Maintenance Plan
- Tree Wire
- Fault Indicators
- Reclosers/SCADA Controlled Switches
- Replacement of Underground System
- 100 and 500 Year Flood Plains
- Underground Damage Prevention Plan

Distribution System Operating Procedures

BED has created contingency plans for the loss of each 13.8 kV distribution circuit and 13.8 kV substation switchgear. These contingency plans are updated annually and used by BED's system operators during planned and unplanned outages to expedite restoring service to impacted customers.

Distribution System Protection

Adequate distribution system protection is required to avoid and/or minimize hazards to the public and BED's lineworkers, to prevent damage to electric utility infrastructure, to reduce the number of customers impacted by outages, and allow for prompt power restoration. Any time a protective device is installed on a circuit, BED performs a protection study to ensure coordination between the new and existing devices on the circuit.

BED has the following protective equipment installed on the distribution and sub-transmission system:

- Circuit breakers are installed at each end of the 34.5 kV sub-transmission line.
- Distribution circuit breakers are installed in each of BED's three substations. These are the primary distribution circuit protection and quickly de-energize an entire circuit to protect the substation transformer from damage.
- Reclosers are similar to circuit breakers but are used as secondary protection mainly on aerial distribution circuits and to tie circuits together.
- Underground distribution switches with protective breakers are similar to circuit breakers but are used as secondary protection on underground distribution circuits and also to tie circuits together.

- Distribution line fuses isolate permanent faults to minimize the size of outages to the smallest possible number of customers interrupted.
- Transformer fuses protect distribution transformers and secondary lines serving individuals or groups of customers.
- Current limiting fuses installed on distribution taps and aerial transformers. These fuses limit the energy released during a short circuit event and protect the associated equipment from failing.
- Over-voltage arresters are used for protection of all aerial transformers, capacitors, normally open switches, normal open points, and at each end of primary underground circuits.

BED's specific sub-transmission protection strategies include:

- The primary forms of protection for the 34.5 kV line are relays with a high-speed line differential scheme on both ends of the line. Relays communicate with each other via fiber, and quickly determine if a fault is within their zone of protection and open the breakers.
- Overcurrent and step-distance relay functions are utilized for backup protection in case the fiber link between the relays is lost.

BED's specific Distribution Protection strategies include:

- The loading on each circuit is typically kept below 65% of the circuit steady-state summer current carrying capability during normal operation and below 80% of relay pickup setting at all operating conditions. This strategy establishes adequate cold-load pickup capability and allows for the switching of loads between circuits.
- Overcurrent protection includes coordination of circuit breakers, reclosers, and fuses. Overcurrent protection is designed to maximize load current, allow for cold load pickup and feeder back up configurations, and maintain sensitivity required to keep the system protected from bolted faults.
- BED uses the so-called "fuse-saving" protection method on all its overhead circuits. This method allows for breakers or reclosers to operate faster than a fuse attempting to clear the fault without causing a long duration permanent outage. The same breaker or recloser recloses after approximately 8 seconds, attempting to restore the power to the circuit. In the case of a transient fault (e.g., squirrel, bird, branch), the fault is cleared at this point and power is restored to all customers. In the case of a permanent fault, the fault is still present and is cleared by the nearest upstream fuse. This method is not used on predominantly underground circuits.
- Most of BED overhead circuits use multiple recloser schemes, which improve the capability of minimizing outages and back feeding circuits. Similarly, all BED

underground circuits use multiple underground switches for the same purpose.

- All BED distribution breakers use synchronism check function, eliminating the potential of connecting non-compatible sources and causing a significant outage.
- All new designs for underground systems use protective and/or switching devices at taps from the main line circuit.
- Short circuit analysis is completed using CYMDIST modeling software. This analysis is done to simulate BED protection schemes as discussed above. The results of this study help to confirm fuse sizing and protective device settings.
- Short circuit data is also used when analyzing Arc Flash hazards on the primary distribution system. CYMDIST uses the detailed distribution model to calculate the available Arc Flash energy at every primary voltage point on the distribution system. This enables BED to coordinate the ratings of safety equipment and personal protective equipment used by line crews.

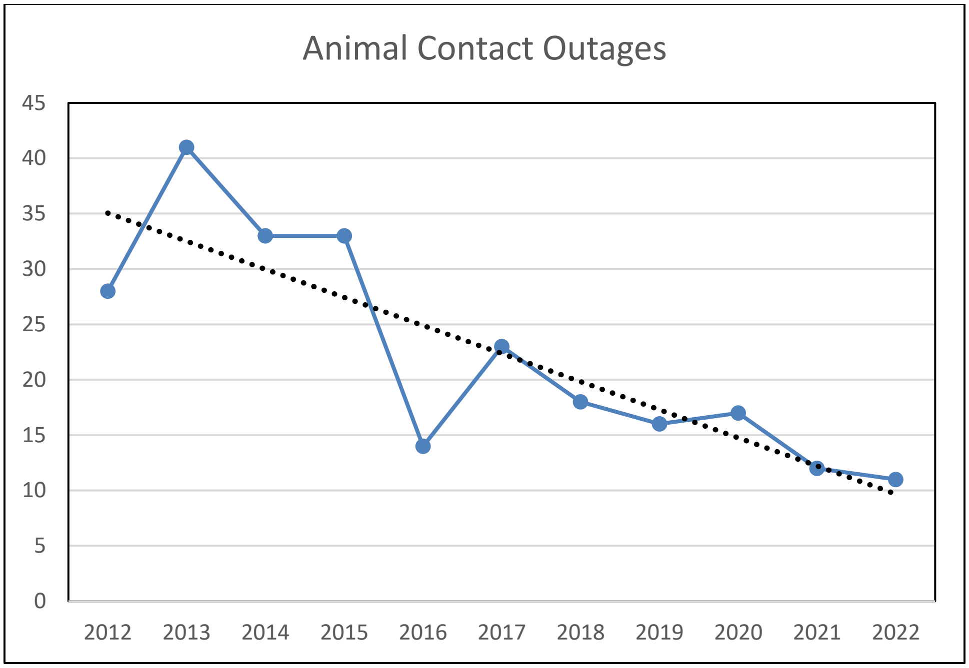
Wildlife Protectors

BED construction standards include the installation of wildlife protectors on all new exposed transformer, capacitor, and circuit breaker bushings and arresters. In addition, BED has started the installation of static guard protectors on reclosers, switches and disconnects.

Most of the unplanned outages on BED's distribution system in year 2015 were caused by animal contact (33 outages). Since year 2013, the number of animal contact outages has continued to trend downward. This improvement is in part to the new construction standards indicated above and the continued effort to survey circuits for equipment that is missing wildlife protection. As of 2019, BED has completed a survey and wildlife protection installations of all distribution circuits.

Figure 3-6 shows BED’s historical animal contact outages.

Figure 3-6: BED Historical Animal Contact Outages



Pole Inspection and Maintenance Plan

The purpose of BED’s Pole Inspection and Maintenance Plan is to identify poles that are damaged or show signs of decay and to take corrective action before the poles fail. BED’s pole inspection program inspects all distribution and streetlight wood poles every seven years and tests the poles that are over 10 years old. Poles are evaluated and inspected for cracks, split, and rot and then tested using industry-standard testing practices. All poles that fail the inspection and testing will be labeled as condemned poles and will be replaced. BED completed a system-wide pole inspection in 2023 and is implementing a replacement plan for those poles identified as condemned.

Overhead Distribution Inspection and Maintenance Plan

The purpose of BED’s Overhead Distribution Inspection and Maintenance Plan is to routinely inspect and maintain the overhead distribution system. BED’s overhead inspection program inspects all overhead utility structures every five years. Structures and all BED attached equipment are visually inspected for signs of wear, damage, missing components, and any non-equipment issues such as trees. BED maintains records of all inspection cycles. Any repairs associated with these inspections are prioritized and scheduled. BED has previewed and discussed with vendors the possibilities around aerial drone inspections. Given the compact service territory within the City of Burlington, this technology does not have the benefit to BED that it might a more rural utility.

Underground Distribution Inspection and Maintenance Plan

The purpose of the Underground Distribution Inspection and Maintenance Plan is to routinely inspect and maintain the underground distribution system. BED's underground inspection program inspects all underground utility installation every 10 years. BED's Underground Distribution Inspection and Maintenance Plan proactively identifies and corrects any issues that are discovered in relation to utility holes and any equipment located underground in utility holes.

Tree Wire

BED uses covered/tree aerial wire where appropriate to limit the number of faults caused by tree contact.

Fault Indicators

BED installs fault indicators on the aerial and underground distribution circuits to assist the field crews in locating the fault location. The fault indicators are installed at major junctions to allow the crews to identify the direction of the fault.

Reclosers/SCADA Controlled Switches

Reclosers improve the reliability of upstream customers by protecting them from all downstream faults and allow for quick restoration of downstream customers for a fault upstream of the recloser. BED has installed aerial reclosers and SCADA-controlled switches on its main distribution circuits, normal open tie points, and on long lateral taps. As of 2022, BED has 467 distribution switching devices (including overhead switches, underground switches, disconnects, reclosers, circuit breakers, and molded vacuum fault interrupters) in the field. Approximately 35% of switches, disconnects, and molded vacuum interrupters are SCADA-controlled while 100% of reclosers and circuit breakers are SCADA-controlled and -monitored. Overall, 43% of all devices are SCADA-controlled and -monitored.

To further improve reliability and expedite service restoration, BED plans to replace the following equipment with reclosers and smart switches:

- Battery Street and Pearl Street underground switch
- University Heights North underground switch
- UVM Reservoir underground switch 6-way
- UVM Reservoir underground switch 4-way
- Battery Street and Cherry Street underground switch
- South Winooski Avenue underground switch
- College Street and Church Street underground switch

Replacement of Underground System

Approximately 47% of BED’s distribution system is underground. Although underground circuits experience fewer outages than aerial circuits, underground circuits are more difficult to repair and result in outages of longer durations. In addition, some of BED’s underground circuits are direct buried. The loss of a direct-buried underground circuit will result in long customer outages. BED’s capital construction plan calls for the replacement of underground circuits throughout the City in an effort to reduce long-duration, unplanned outages, improve operating efficiencies, and coordinate with the City of Burlington’s Street Pavement Plan. Underground circuits are replaced based on first-hand knowledge of specific problems, age of cable, type of existing installation (direct buried, availability of spare conduits), type of load, engineering judgment, coordination with Department of Public Works pavement plans or city/state road rebuild projects, and budget constraints.

Over the next five years, BED plans to rebuild the aging underground infrastructure at:

- Summit Ridge
- Lake Forest
- Battery Street
- St. Paul Street between Bank and Cherry Streets
- 2L5 Feeder from Main St down College Street via South Winooski Avenue
- 1L2 Feeder along College Street
- Deforest Road
- Oakledge Drive
- Juniper Terrace

100- and 500-Year Floodplains

BED’s McNeil, East Avenue, and Queen City substations are not within FEMA-designated flood hazard areas. This conclusion is based on BED’s review of the Vermont Agency of Natural Resources Atlas program using the FEMA flood layers for reference.

Underground Damage Prevention Plan

BED has an underground damage prevention plan that complies with Vermont Public Utility Commission Rule 3.800 and 30 V.S.A. Chapter 86. BED’s underground cable locators locate BED’s underground facilities. The plan document focuses on the requirements to locate BED’s underground facilities upon receiving notification from Dig Safe Systems, Inc., closely monitor BED’s own excavation efforts, and manage our damaged infrastructure repairs with an emphasis on employee/public safety and service restoration.

Volt/VAR Optimization

The voltage and VAR flow on BED's distribution system are controlled by the substation transformer LTCs controllers, and fixed and switched capacitor banks on the distribution circuits.

The East Avenue and Queen City substation transformer LTCs controllers are owned and maintained by VELCO while the McNeil substation transformer LTC controller is owned and maintained by BED. The East Avenue, Queen City and McNeil substation transformers LTCs are set to hold voltage at the peak hour between 122.1V and 124.6V (set point of 123.4V and bandwidth of 2.5V on a 120V basis) at the substation 13.8 kV bus. The voltage at the substation transformer LTC is set as low as possible for the summer peak hour while still providing all the customers on each circuit with ANSI C84.1-2011 Range A voltage during normal operation and ANSI Standard C84.1-2011 Range B during contingencies and meeting ISO OP-13 Standards for 5% Voltage Reduction.

The substation transformer LTCs regulate the 13.8 kV bus voltage for all circuits connected to the substation at the 13.8 kV bus. As a result, all the distribution circuits fed from the substation transformer have the same voltage set point. BED does not use the Line Drop Compensation for voltage regulation because the transformer LTC regulates the 13.8 kV bus voltage, two large generators (Winooski 1 Hydro and Lake Street Gas Turbine) are connected directly to BED's distribution circuits, and the distribution system is operated in a network configuration when the gas turbine is running.

As discussed in the Optimal Locations of Capacitor Banks section, BED remotely controls the capacitor banks. The SCADA system monitors each circuit's VAR flow and will send an alarm to the system operator when the VAR flow is outside of the set points. One or more capacitors are then either turned on or off to return the VAR flow to within the limits. BED has installed stand-alone capacitor bank control units on all SCADA-controlled capacitor banks and has connected them to the fiber system. These controllers operate independently on each circuit to control the VAR and voltage.

The LTC controllers at each of the three substations allow BED to operate the distribution system at a lower voltage setting during certain months of the year taking into consideration ISO OP-13 Standards for 5% Voltage Reduction. Monitoring of the AMI system voltage information allows for the LTC parameters to be optimally set and provide feedback to BED to assure the voltage stays within required parameters.

BED is in the process of acquiring and implementing over the next few years a full-featured Advanced Distribution Management System (ADMS), which will include a modern SCADA system with a fully integrated Distribution Management System, and Outage Management System. This platform will use the existing system data from SCADA field devices to automatically optimize system voltage and VAR loading on each of the distribution feeders and substations by managing substations LTCs and distribution capacitor banks.

Grid Modernization/Distributed Generation/Strategic Electrification

BED's 2022 base case 90/10 peak load forecast assumed a low penetration of EV chargers and heat pump load, consistent with what BED has experienced with technology adoption. In this 90/10 peak load forecast scenario, the installation of EV chargers and heat pumps doesn't add a significant load on BED's distribution system. While in general this small load addition may not impact BED's distribution system main trunk lines, it may create line overloads if the load additions are concentrated on a small radial tap. In addition, depending on the number of EVs and heat pumps being connected to an existing transformer, the total load added may result in an overload on the distribution transformer, secondary wire, and/or service wire and require the replacement of the overloaded equipment. BED's AMI system, in conjunction with the planned grid analytics software, plays a major role in identifying transformers and secondary/service wires that may be impacted by the penetration of the EVs and heat pump load.

When customers do apply for service upgrades related to electrification, BED analyzes the transformer and secondary loading to determine if any system upgrades local to the customer are necessary due to the electrification upgrade (i.e., service conductor, secondary conductors, and the transformer). In 2022, there were 120 residential service applications to install new or upgrade to a 200-ampere rated panel or larger. While we can't determine the exact number of these that were related to electrification, it is often an indication of large load increases when a customer increases their main panel size. In 2022, it is estimated that approximately 14 of those service applications resulted in some level of distribution upgrade cost (e.g., service conductors, secondary wire) and of those 14, there were six applications that resulted in a transformer upgrade due to the customer load. This is anticipated to increase in quantity year-over-year as electrification grows within BED's service territory. Due to anticipated increase in service upgrades related to electrification, BED is in the process of reviewing its Line Extension Tariff and Operating Guidelines.

The low penetration and small amount of distributed renewable generation on BED's distribution system has not yet presented operational issues associated with reverse power flow and solar generation intermittency. Given BED's compact service territory and lack of open space for large renewable projects, as renewable penetration increases over time, BED does not anticipate typical system wide operational issues such as high voltage at the end of feeders, or backfeeding of substations to the sub-transmission/transmission network. Depending on the type of connection, size of the proposed units, and total generation on BED's circuit, one or more studies (feasibility, impact, stability, facility) may be required to identify and remedy potential localized problems. BED has also developed Distributed Generation Interconnection Guidelines that are posted on BED's website. In addition, BED has developed a solar map to show the distributed generation on each circuit and provide a preliminary screening tool to assess BED's circuit capabilities to accept new distributed renewable generation projects.

NZE 2030

Refer to the Net Zero Energy chapter, Potential Distribution System Impacts section for an update on the initial estimated cost to the 102.8 MW analysis previously conducted, and the updated 120 MW study results.

Additional Grid modernization

To support future potential high penetration of electric heating/cooling, EV charging stations, battery storage, and distributed renewable generation, BED will continue to modernize its distribution system and internal software platforms. The following are BED's current initiatives to modernize the distribution system:

- GIS integration
- Asset Management System
- Distributed generation resources
- Outage Management System
- AMI Integration
- Distribution automation

Geographic Information System (GIS)

BED maintains a comprehensive GIS that includes the primary distribution circuits, secondary system, service wires, transformers, and distributed generation. In addition, customer service points are linked to distribution transformers, significantly simplifying the transformer loading evaluations. The GIS database is also used to track BED's assets. The quantities and conditions of all poles and equipment attached on the poles are stored and maintained in the GIS database.

Distributed Generation Resources

BED has an online map showing the distributed generation ("DG") on each circuit, both active and in the process of becoming active, the DG size and type, and the circuits capable of accepting additional DG. This online map can be used as a preliminary screening tool to assess the ability of BED's circuits to accept new distributed renewable generation projects.

https://www.burlingtonelectric.com/distributed-generation

Through the CYME Gateway software mentioned above, BED can extract the data from GIS and model every DG resource on its distribution system in the CYMDIST modeling software. This allows for more accurate system modeling and DG impact analysis when reviewing future DG projects.

Outage Management System

BED maintains an automatic feed to the VTOutages website based on the outage notification capabilities of its AMI meters.

It should be noted that this system has a limitation compared to a fuller-featured Outage Management or Distribution Management System in that it is not able to count meters where outages are not reported by the AMI system. This situation results from either a mesh network meter being out of communication during the outage ("islanded" without a communication path and thus unable to report), or due to the customer having opted out of AMI metering. As a result, the reported information would likely represent a lower number of customers without power, with the relationship being dependent on the size of the outage. For example, if a single meter reports an outage, it is likely that is very close to the extent of the outage. However, if the full system were out, the reported count would be low by the number of non-AMI and "islanded" meters.

As noted above, BED will be implementing over the next few years a full-featured ADMS. This platform which includes a fully featured Outage Management System to respond to and track outages. This system will also integrate into existing BED systems such as GIS, AMI, and MDMS to provide more transparency and information to process outages.

AMI Integration

BED has completed the deployment of AMI across its entire service territory, replacing nearly all of the electric meters with advanced AMI meters. The remaining meters on BED's system are 475 Automated Meter Reading (AMR) meters and 267 non-AMI/AMR meters. BED has established a link between meter accounts and the transformer supplying these accounts in the GIS. With this data link and access to the MDMS, Engineering staff are able to create load reports for existing transformers and size future transformers as well as develop other reporting tools. This process is to be automated with the implementation of the grid analytics software mentioned above.

Distribution Automation

BED's SCADA system allows BED to collect operational and planning data, and remotely control and operate key field devices such as breakers, reclosers, switches, capacitor banks, and transformer LTCs. The SCADA system increases customer satisfaction through reduced service interruptions, less customer down time, and improved quality of supply.

All BED substation relays are microprocessor-based. The protective devices associated with substation breakers, reclosers, and underground switches allow temporary faults to be removed from the system before automatically restoring normal service. In conjunction with fuses, the protective devices give BED the capability to limit permanent faults to the smallest possible number of customers. These devices have greatly increased BED's ability to isolate faults, clear temporary faults, reduce the number of customers impacted by outages and restore service more quickly to customers when outages do occur.

BED has installed reclosers on its aerial distribution circuits to isolate the faulted part of a circuit and improve reliability. These reclosers are also controlled by the SCADA operators.

BED has installed pad-mounted switches with means to automatically transfer critical customer load from a faulted circuit to a different circuit within seconds. In addition, BED has installed pad-mounted switches with protective relays on its underground distribution circuits to isolate the faulted part of a circuit and improve reliability. These switches are also controlled by the SCADA operators.

BED plans to install new and replace/upgrade existing aerial switches and disconnects with reclosers and SCADA-controlled switches as discussed in section 4.1.7. These devices will be able to provide real-time information such as amps, kV, kW, and kVAR.

BED has installed stand-alone capacitor bank voltage and VAR control units on all SCADA-controlled capacitor banks. These controllers operate independently on each circuit to control the VAR and voltage. The controllers are also controlled by the SCADA operators.

Additional steps toward Distribution Automation includes the deployment of an ADMS.

Emergency Preparedness and Response

BED participates in the statewide emergency preparation conference calls. Based on the available information from these calls, BED assesses the appropriate response to an anticipated event and responds appropriately. If additional crews are needed, there are sources available to BED. BED is a member of the Northeast Public Power Association ("NEPPA")'s Mutual Aid program and as a result has access to numerous municipal utility crews in the northeast. In addition, BED would reach out to GMP and/or Vermont Electric Cooperative ("VEC") to provide aid if needed. In the event that BED's needs are not met by the NEPPA Mutual Aid program, GMP, or VEC, BED would seek to use contract crews.

Currently VTOutages is updated automatically when outages occur and during system restorations as described in the Outage Management System section above.

BED currently contacts customers for planned outages using several forms of communication. Customers are contacted directly by using phone calls, emails, letters or the use of door hangers. Customers are contacted well in advance and reminders are sent before the date of the planned outage. In the event of unplanned outages, customers can contact BED during normal business hours for information. After-hours calls will be answered either by BED dispatch office or an off-site answering service. Voice messages are used to let customers know that an outage is occurring and that crews are responding. BED also posts unplanned outage information to the BED website and various social media platforms.

Utilities Coordination

BED coordinates pole installations and construction of underground distribution projects with Comcast Corporation, Consolidated Communications Holdings, Inc. (formerly FairPoint Communication, Inc.), and Burlington Telecom. This coordination between utilities cuts costs through sharing of trenching costs, repaving, and permit fees, and also expedites the transfer from old installations to new ones.

In addition, BED coordinates its underground construction projects with City of Burlington Department of Public Works street paving plans to eliminate the City excavation fees when trenching in the road.

Track Transfer of Utilities

BED uses the National Joint Utilities Notification System database to track transfer of utilities and dual pole removal. This is a database that is accessible by BED and all of the other entities that would attach to a utility pole. When a pole is changed out, it is logged in the system and all entities attached to the pole are notified to transfer their wires or equipment to the new pole. Once the last attachee is removed from the old pole, the owner of the pole is notified to remove the old pole.

Relocating Lines to Roadside

In the process of re-building BED's old aerial lines located behind private properties, BED evaluates the feasibility and cost of relocating these lines into the City right-of-way along the roadway and sidewalk areas. Typically, these relocations take many years to complete due to the scope of work, need for securing easements, and cost for potentially placing the lines underground.[48]

Vegetation Management Program

The purpose of BED's Vegetation Management Program is to maximize employee and public safety and minimize power outages associated with tree contacts with BED distribution circuits.

BED has adopted a tree trimming program based on outage history, right-of-way requirements and constraints, as well as the associated rates of growth for the tree species indigenous to the City of Burlington.

BED has approximately 132 miles of distribution circuits and has divided the City into three maintenance sectors. Every three years a sector is given priority and our trimming efforts are concentrated in that area. In addition, BED augments its trimming cycle program by identifying specific areas of need through inspection patrols, outage reports, feedback from customers and BED employees, as well as other agencies such as the Burlington Parks and Recreation Department.

During our trimming cycles, BED's inspector and tree trimming contractors will document any danger trees outside the right of way. BED then works with the City of Burlington's Arborist and private property owners on the removal of these trees.

The City of Burlington's Arborist contributed the information in Table 3-2 about the various species of trees and their associated growth rates. According to the City Arborist these same growth rates apply to pruned branches of healthy trees. The growth rates, however, do slow whenever the health of a tree is compromised.

[48] The cost of placing BED's lines underground within a paved portion of a City street includes a City Administrative and Excavation fee of approximately $25 per square foot

Table 3-2: Tree Growth Rates

Species	Growth Rate	Growth Rate After Pruning (assuming healthy tree)
Ash Species	Fast	Fast
Birch Species	Medium	Medium
Box Elder	Fast	Fast
Cedar, White	Medium	Medium
Cherry, Black	Medium	Medium
Cherry, Ornamental	Fast	Fast
Crabapple Species	Medium	Medium
Elm, Species	Fast	Fast
Hackberry	Medium/Fast	Medium/Fast
Honeylocust	Fast	Fast
Hawthorn Species	Medium	Medium
Ginkgo	Slow	Slow
Linden, Species	Medium/Fast	Medium/Fast
Locust, Black	Medium/Fast	Medium/Fast
Maackia, Amur	Slow	Slow
Maple, Amur	Medium	Medium
Maple, Hedge	Slow	Slow
Maple, Norway	Fast	Fast
Maple, Red	Fast	Fast
Maple, Sugar	Medium	Medium
Maple, Tatarian	Slow/Medium	Slow/Medium
Oak, Red	Medium	Medium
Oak, White	Slow	Slow
Pine, White	Fast	Fast
Pear, Ornamental	Fast	Fast
Spruce, Species	Slow	Slow
Willow, Species	Fast	Fast

BED uses standard pruning, flat cutting, and brush mowing techniques in its vegetative management program. BED has selected these types of vegetative management controls to minimize our environmental impact and to comply with City ordinance prohibition on the use of chemical herbicides.

BED mainly employs the services of the Burlington Parks Department, qualified independent tree-trimming contractors, and its own lineworkers to carry out its vegetation management program.

Tree-related outages in year 2022 were approximately 8% of BED's total outages compared to the 5-year average of 7.1% and 10-year average of 5.2%. BED's vegetation management plan has been successful in reducing the number of outages caused by tree contact. BED feels that we have achieved the appropriate ratio of spending to tree outage avoidance and will continue to budget approximately $100,000 per year for vegetation management.

BED maintains a vegetation management tracking database that identifies the employee overseeing the project, the circuit number, the date, and location as well as what entity performed the work.

Table 3-3 provides the total miles of BED's distribution system, miles needing trimming, and trimming cycle:

Table 3-3: Distribution System Trimming Miles and Cycle

	Total Miles		Miles Needing Trimming		Trimming Cycle	
Transmission						
Distribution	132		69.9		3-years	
	FY2020	FY2021	FY2022	FY2023	FY2024	FY2025
Amount Budgeted	$110,000	$115,000	$124,500	$129,000	$131,580	$134,212
Amount Spent	$95,640	$72,381	$129,600	$124,724		
Miles Trimmed	23.8	22.26	26.4	20.33	24.11	26.4

Studies & Planning

Long-Range Planning Study

In 2022, BED performed a long-range planning study to evaluate the impact of the redevelopment of the old Burlington Town Center Mall with the CityPlace project. This project proposes an estimated 5.5 MW of peak load addition over the next several years when all three phases are complete.

The results of this study showed the need for two 600 kVAR capacitor banks at the proposed CityPlace Phase 1 and Phase 2 buildings. No distribution system upgrades were identified to be able to serve this load as the three phases will be connected to three different circuits, balancing the load across these three feeders.

In addition to the CityPlace load additions, BED studied the system impacts of the proposed District Energy System electric boiler. This project proposes an intermittent and interruptible 10 MW electric boiler load located at the BED 13.8 kV McNeil substation. This load would be fed from a dedicated radial tap, connected to a new feeder added to the BED McNeil substation. The customer has elected for no primary feeder redundancy. To reduce system impacts, the customer will allow BED to interrupt the load when necessary to prevent system equipment overloading. The resulting study indicated the need for a single aerial 600 kVAR capacitor bank on the McNeil Line 1 circuit to support voltage during contingencies. No other upgrades were identified beyond the interconnecting facilities to serve the load.

Capital Distribution System Projects

The following is a list of BED's capital distribution system projects that were constructed between FY20 and FY23:

- Replace 30 condemned poles
- Replace recloser 112R
- Replace recloser 252R
- Upgrade aerial switch 815S
- Upgrade aerial switch 227S
- Ethan Allen Pkwy conversion from single-phase to two-phase
- Replace/relocated underground distribution on Edgemoor Dr
- Replace/relocated underground distribution on Lyman Ave
- Replace/relocated underground distribution on Scarff Ave
- Replace 6-way switch (721S/722S/743S/702S/703S/705S)
- Replace 6-way switch at Milot/College St
- Replace 5-way switch at Pearl St and S Prospect St
- Replace 5-way switch (821S/401S/727S/349S/233S)
- Replace 4-way switch (731S/736S/760S/761S)
- Replace 4-way switch at Main St and S Prospect St
- Replace 4-way switch at Battery St and Pearl St
- Reconductor 4,000′ of the McNeil Line 1 aerial circuit
- Reconductor 3,000′ of the McNeil Line 4 aerial circuit (Heineberg Rd)
- Reconductor 2,400′ of the East Avenue Line 5 underground circuit
- Reconductor 2,200′ of the McNeil Line 2 underground circuit
- Convert Appletree Point from 4kV to 13.8 kV primary
- Convert Sunset Cliff Rd from 4kV to 13.8 kV primary
- Champlain Parkway
- Virtualization of SCADA servers
- Replacement of SCADA firewall

The following is a list of BED's capital distribution system projects planned for the next three years:

- Replace 75 condemned poles
- Reconductor 8,100' of the East Avenue Line 5 underground circuit
- Replace 6-way switch at University Heights North and Main St
- Replace 6-way switch at Main St Reservoir
- Replace 4-way switch at Main St Reservoir
- Replace 4-way switch at Battery St and College St
- Replace 4-way switch at Lake St
- Replace 4-way switch at Battery St and Cherry St
- Replace 4-way switch at Main St and S. Willard St
- Replace 3-way switch at S. Winooski Ave between Main St and College St
- Replace 5-way switch at College St and Church St
- Replacement of SCADA network switches
- Rebuild Austin Dr
- Rebuild Sunset Cliff Rd
- Ethan Allen Pkwy conversion from two-phase to three-phase
- Rebuild Summit Ridge
- Rebuild Oakledge Dr
- Replace live front transformer at Pearl St Courthouse
- Replace live front transformer at Decker Towers
- Replace Pole P2296 on Flynn Ave
- Champlain Parkway
- Transfer load from Queen City Line 1 circuit to Line 4
- Relocate aerial circuit on Bank St for Great Streets project
- Replace underground conductors along Battery St
- Replace underground conductors along College St between Pine St and St Paul St
- Replace underground system at UVM Aiken Center
- Replace underground system at Village at North Shore
- Rebuild Lake Forest
- Replace 346D disconnect switch with SCADA controlled switch
- Replace 917S manual switch with SCADA controlled switch
- Rebuild Juniper Terrace
- ADMS Phase 1 – Replace existing SCADA system (incl. operations terminals and SCADA system display)

Maintenance & Implementation of System Efficiency

Through the strategies and procedures described above, BED proactively maintains the efficiency of its distribution system. BED's commitment to linking software and equipment together will further enhance the automation of efficiency efforts and improve our ability to operate the system as efficiently as possible in the future.

Implementation of Distribution Efficiency Improvements

The following summarizes BED's cost-effective distribution efficiency projects and implementation timeline:

- Balance the load between 1L1 and 1L4 as well as 3L3 and 3L5 circuits. One system re-configuration case is scheduled to be completed in FY24 and the other case that requires further analysis to be completed in FY25 if determined not to have adverse impacts to other system operating requirements.
- The following load transfers were identified as cost effective and are scheduled to be implemented in FY25:
    - Transfer both feeds into Little Eagle Bay to Phase C
    - Transfer the single-phase tap on Forest St to Phase A
    - Move transformer #4821 to Phase C
    - Move transformer #2284 to Phase C

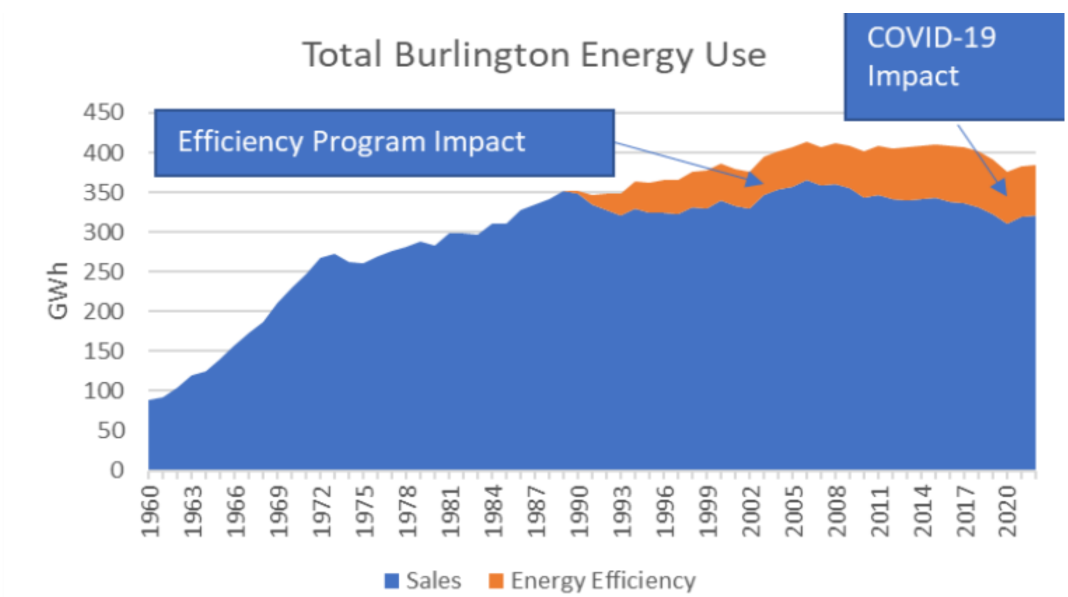
4. Energy Services

Introduction

BED has been providing comprehensive energy services to customers for over 30 years. Although such services have evolved over time to include beneficial electrification measures, which encourage customers to replace fossil fuel technologies with renewable electric technologies, right-sizing electrically powered devices and reducing electricity continues to be a primary service.

The long-term cumulative effect of our energy efficiency services has been significant. Over decades of continuous program funding and implementation, BED's investment in electric efficiency has generated net total resource benefits worth approximately $5.9 million. Cumulative lifetime savings have amounted to roughly 2,000,864 MWh.[49] Each year, the community saves millions of dollars—on balance—in electric energy expenditures because of energy efficiency. These savings are re-circulated back into the community, creating additional local jobs and economic activity. In addition, because BED's electric efficiency work results in a cost-effective resource, energy efficiency programs have helped to offset the need for additional purchases of electric generation and capacity. Indeed, electric loads have remained relatively flat for since the 1990s due in part to BED's energy efficiency investments.

Figure 4-1: Burlington's Total Energy Use, 1960-2022



[49] See BED EEU 2022 Annual Report.

We expect the importance of electric energy efficiency to increase over the coming years. As more customers convert to electric vehicles, advanced heat pumps, and other electric appliances (e.g., induction cooktops), efficiency services will need to continue to evolve. This evolution will entail the integration and management of more dynamic and real-time demand resources on the customer's side of the meter, weatherization of buildings, and incentives for purchasing beneficial electric measures that use less energy per unit of input.

This chapter provides an overview of BED's energy services programs. We begin with a historical look at the electric efficiency investments that are embedded in our planning efforts and continue to have positive impacts on our base load forecast. We also discuss BED's proposed future investments in electric efficiency, their benefits, and how our existing efficiency programs will be paired with BED's evolving beneficial electrification programs. Through this pairing of electric efficiency and beneficial electrification, BED's overall objective is to provide customers with comprehensive energy services that are designed to meet the requirements of our Order of Appointment, Vermont's Renewable Energy Standard,[50] and the City's Net Zero Energy ("NZE") objectives.

Electric Energy Efficiency

Historical Results

BED has been providing energy services to customers since 1990. Past investments in electric energy efficiency services, along with increasing amounts of net-metered PV systems, have helped to flatten our load, allowing BED to defer growth-related upgrades to its distribution system. Efficiency has also helped to reduce the need to acquire additional wholesale energy on the spot market and/or arrange for the purchase of new power through contracts with renewable energy generators.

Current Electric Efficiency Programs

BED's efficiency services are delivered through five main programs: business existing facilities, business new construction, efficient products, residential existing homes (which includes services to income-eligible households), and residential new construction. Table 4-1 shows average annual investments and savings by program over the past eight years.

[50] 30 V.S.A. § 8002-8005

Table 4-1: Energy Efficiency Program Costs and Savings, 2015–2022

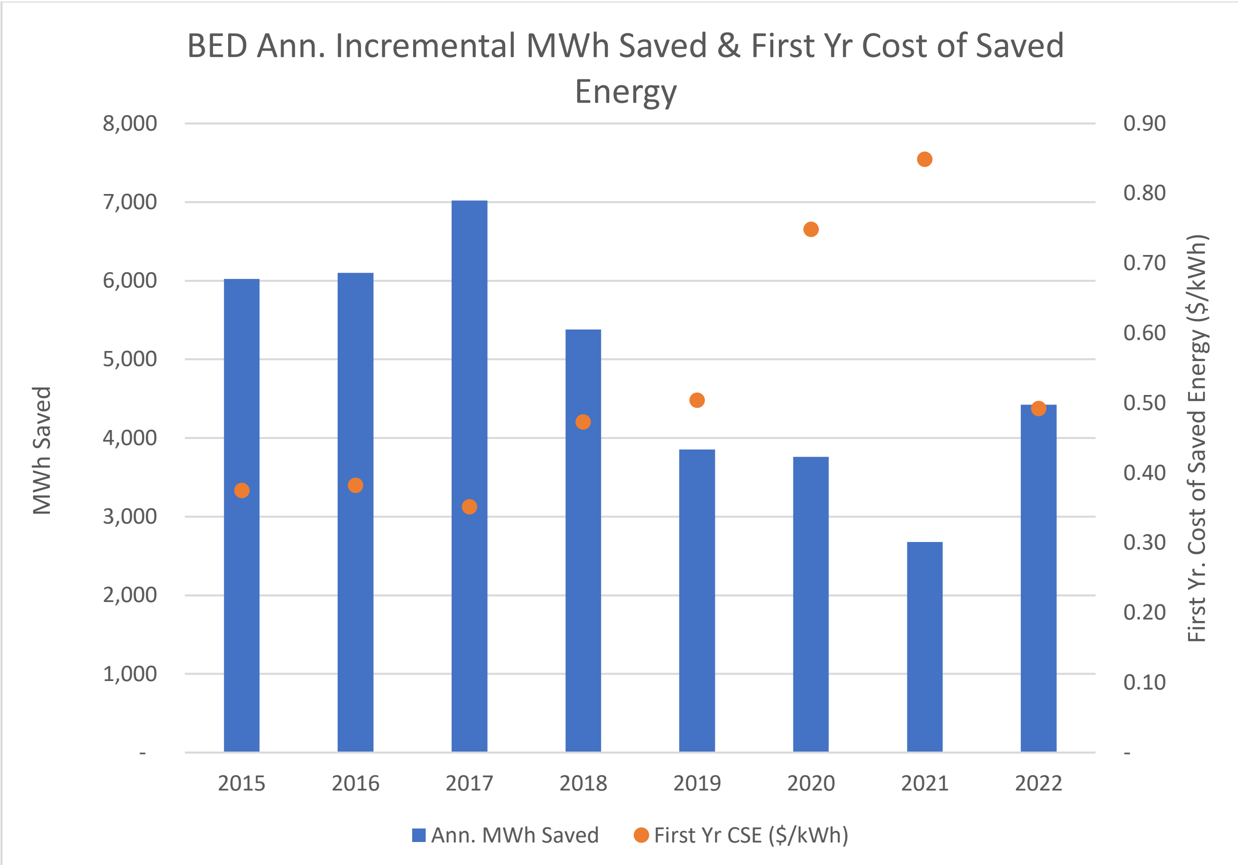
Program	Total Program Costs	Net MWh Savings	BED First yr CSE ($/kWh)	BED Levelized CSE ($/kWh)
Business Existing Facilities	$ 1,033,371	2,356	$ 0.44	**$ 0.04**
Business New Construction	$ 517,200	849	$ 0.61	**$ 0.06**
Efficient Products Program	$ 378,766	1,285	$ 0.29	**$ 0.03**
Residential Existing Facilities	$ 314,442	280	$ 1.12	**$ 0.11**
Residential New Construction	$ 126,573	101	$ 1.25	**$ 0.12**
Total	**$ 2,370,352**	**4,872**	**$ 0.49**	**$ 0.05**

Historically, BED's energy efficiency programs have reduced electric consumption by between 2,600 to 7,000 MWh annually. The amount of savings has fluctuated from year to year due to economic factors such as economic housing starts and renovations and customers' appetite for business starts, expansions, or new investments. The 2020 COVID pandemic had a material impact on the level of efficiency program activity as businesses sent their workers home and postponed investments in their commercial facilities. This resulted in a large two-year decline in BEDs electric savings. Energy efficiency investments have only recently begun to rebound as businesses are beginning to resume construction projects.

As shown inFigure 4-2, annual incremental MWh savings declined from 2017 through 2021. Savings declined in 2020 and 2021 as a result of the COVID pandemic. Prior-year reductions in MWh savings can be attributed to increasingly stringent appliance standards, particularly in lighting. As a consequence, the pool of cost- effective savings has been diminishing over the past several years.

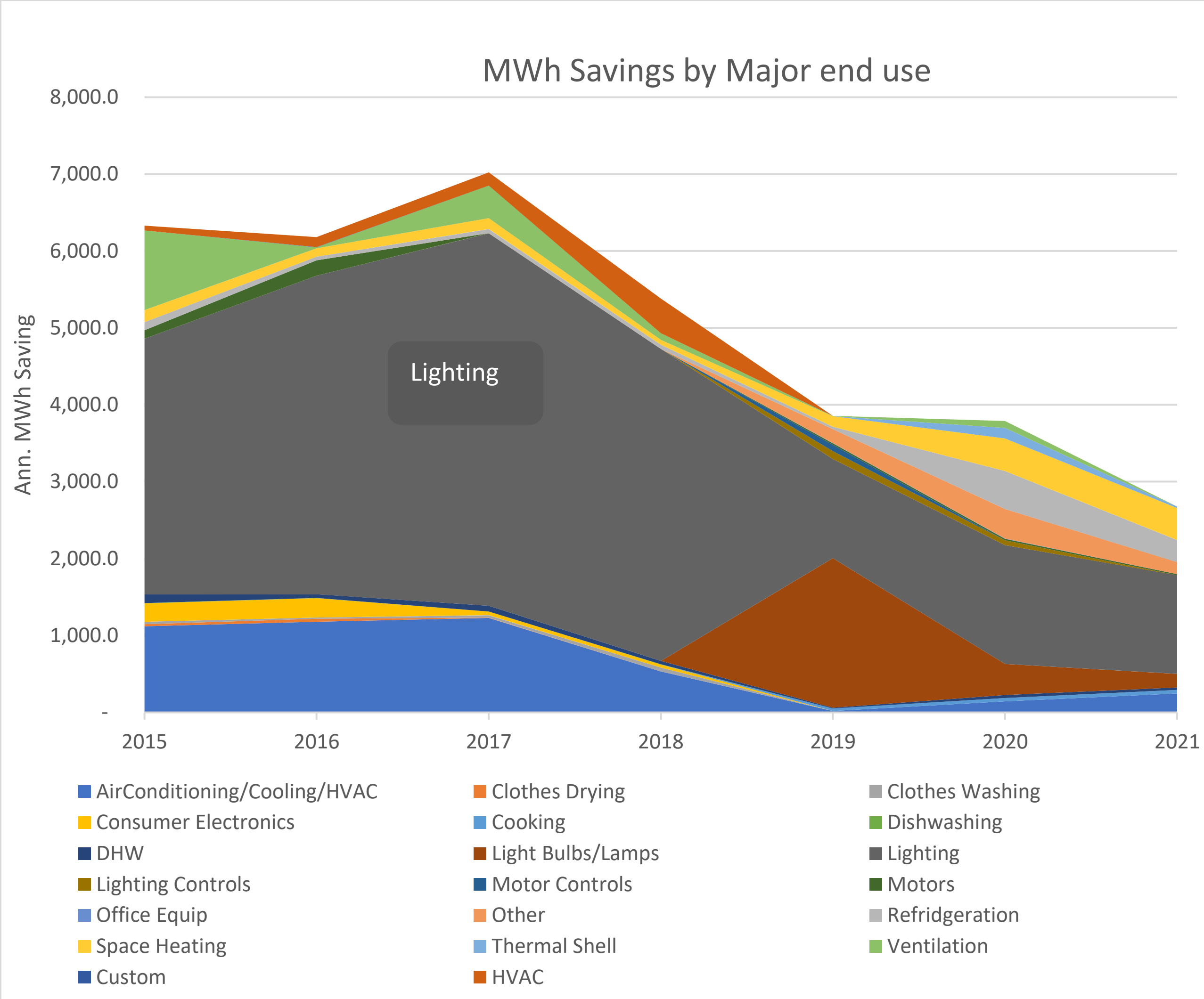
In the recent past, electric energy savings from efficiency programs have amounted to roughly 0.5%-2% of annual retail sales. First-year cost of saved energy has ranged from $0.30 to $0.80 per kWh saved. Over time, MWh savings accumulate over the life of installed efficiency measures, 10-12 years on average, and even longer for new construction projects. These savings cost BED roughly $0.03 -$0.07 per kWh on a levelized basis. When compared to the levelized cost of wholesale energy ($0.05 to $0.08/kWh), energy efficiency has proven to be a sound investment that has contributed to BED's efforts to comply with 30 V.S.A. § 218c.

Figure 4-2: Energy Efficiency Annual MWh Savings and First-Year Cost of Saved Energy, 2015-2022



In past years, installation of more efficient lighting technologies has produced the vast majority of electrical savings. But, as Figure 4-3 illustrates, lighting savings have been diminishing as LEDs have become more prevalent. Starting in 2024, LED lighting will become the standard baseline measure, thus eliminating most future lighting-related savings except for lighting design, building controls, and, for a limited time, retrofitting four-ft linear fluorescent lamps in commercial establishments. This energy efficiency opportunity is discussed further below.

Figure 4-3: Energy Efficiency MWh Savings by Major End Use, 2015-2022



The Future of Energy Efficiency

BED has filed with the Public Utility Commission a new Demand Resource Plan ("DRP") covering the performance period of CY 2024 through CY 2029.[51] In this DRP, BED proposes to invest between $2.8 million to $3.0 million annually (inclusive of Development & Support Service ("DSS") and other costs) to acquire approximately 4,500 MWh of electric savings each year. Over the longer term, proposed resource acquisition budgets and savings, on an annual incremental basis, are as shown in Figure 4-4 and Figure 4-5.

Figure 4-4: EEU Resouce Acquisition Budget Forecast, 2024-2043

[51] See Case #22-2954-PET.

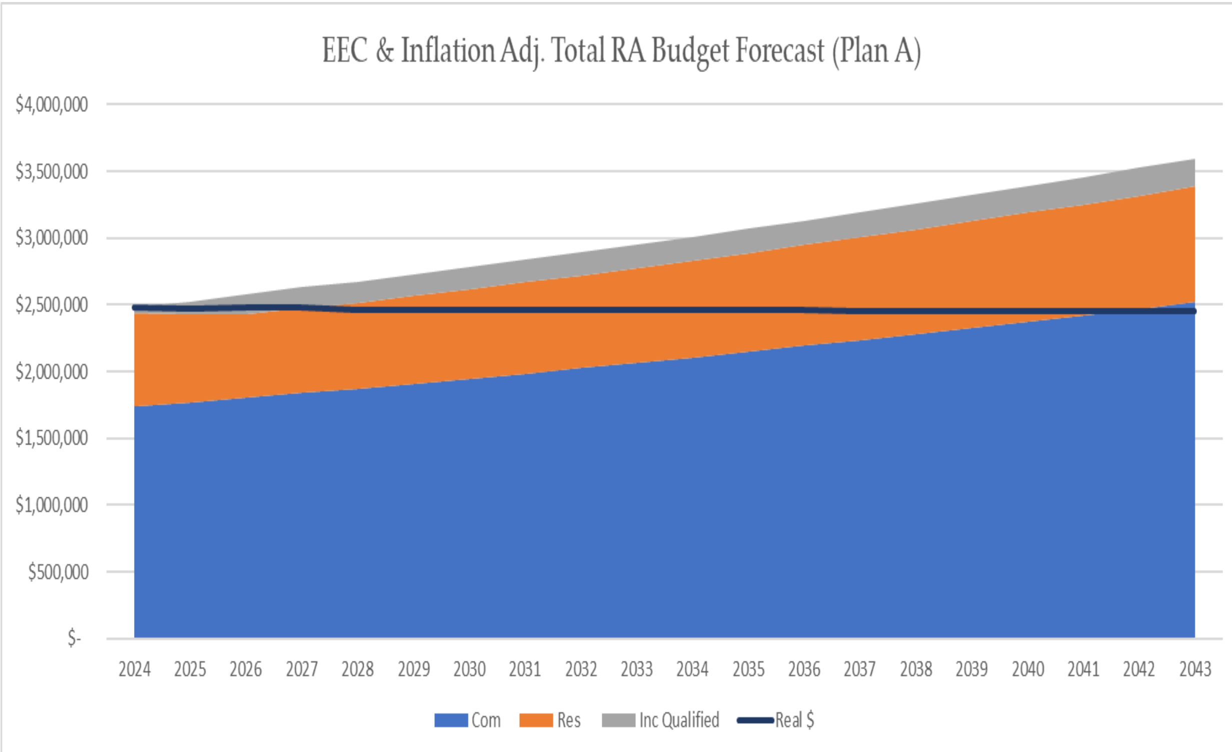
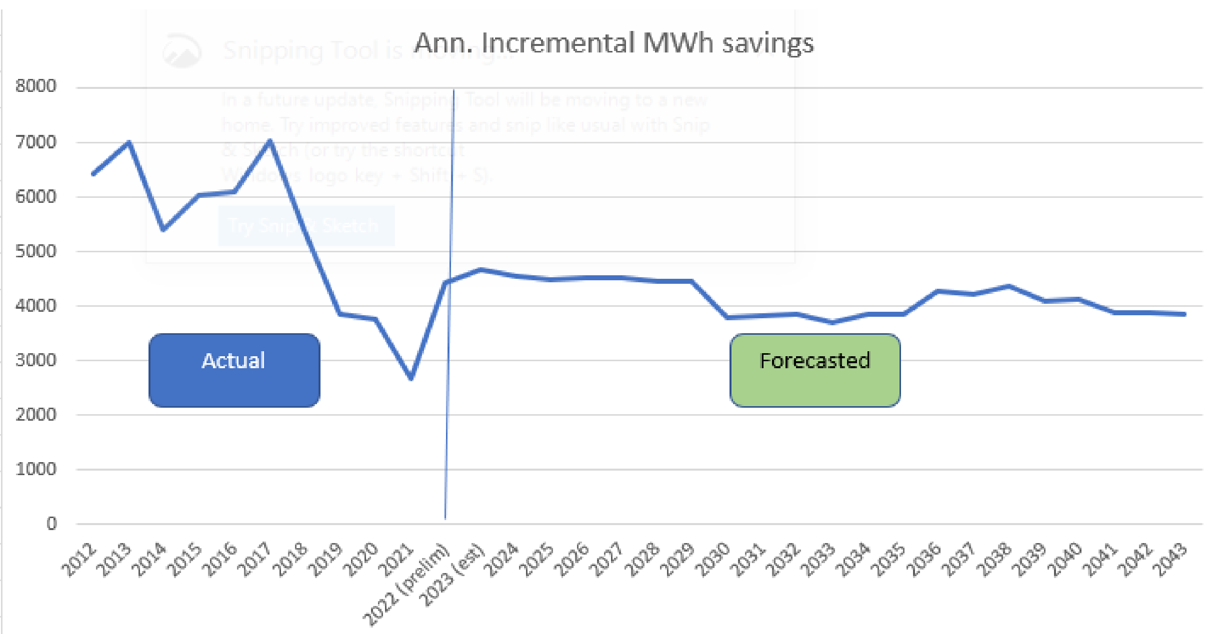
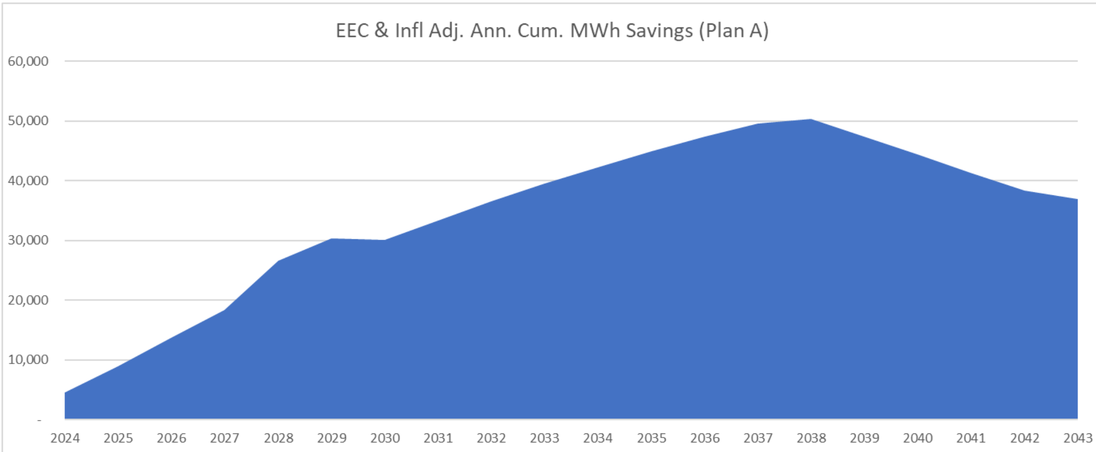


Figure 4-5: EEU Annual Incremental MWh Savings Actuals and Forecast, 2012-2043



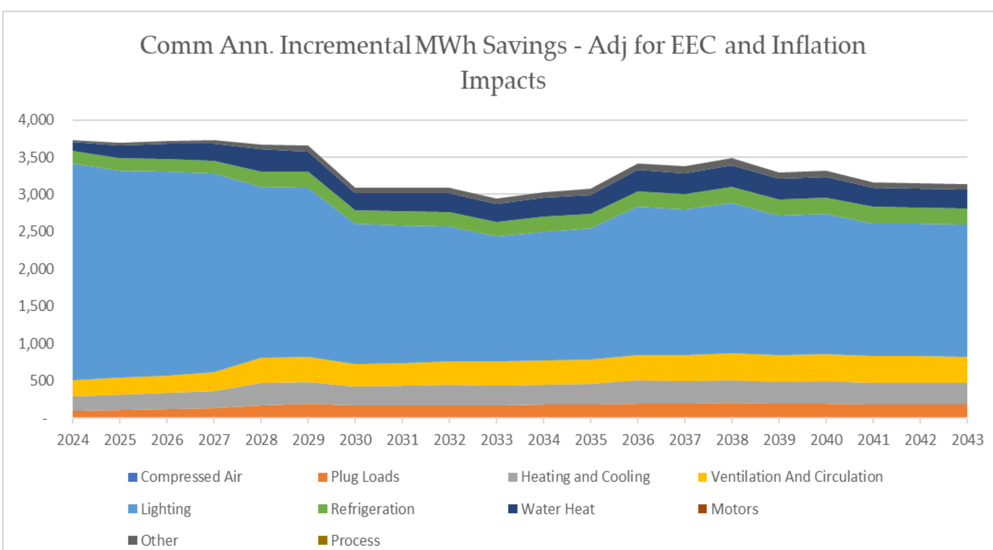
Over time, annual incremental future savings accumulate with each year as new electric measures installed typically remain in service for 10 to 12 years. By 2042, BED anticipates cumulative electric savings could top out at over 50,000 MWh before leveling off in the outer years as measures installed earlier in the planning period reach the end of their useful lives and are not replaced.[52]

Figure 4-6: EEU Cumulative MWh Savings Forecast, Inflation-Adjusted, 2024-2043



During the upcoming DRP performance period, savings will likely transition away from more traditional electric measures to new types of electric savings, including, but not limited to, advanced heat pumps, weatherizing buildings predominantly heated by advanced heat pumps, lighting designs, refrigeration, advanced motors, and improvements to Building Energy Management Control Systems. In the commercial sector, forecasted savings by major end use are shown in Figure 4-7.

Figure 4-7: Forecast Commercial EEU MWh Savings by End Use, 2024-2043

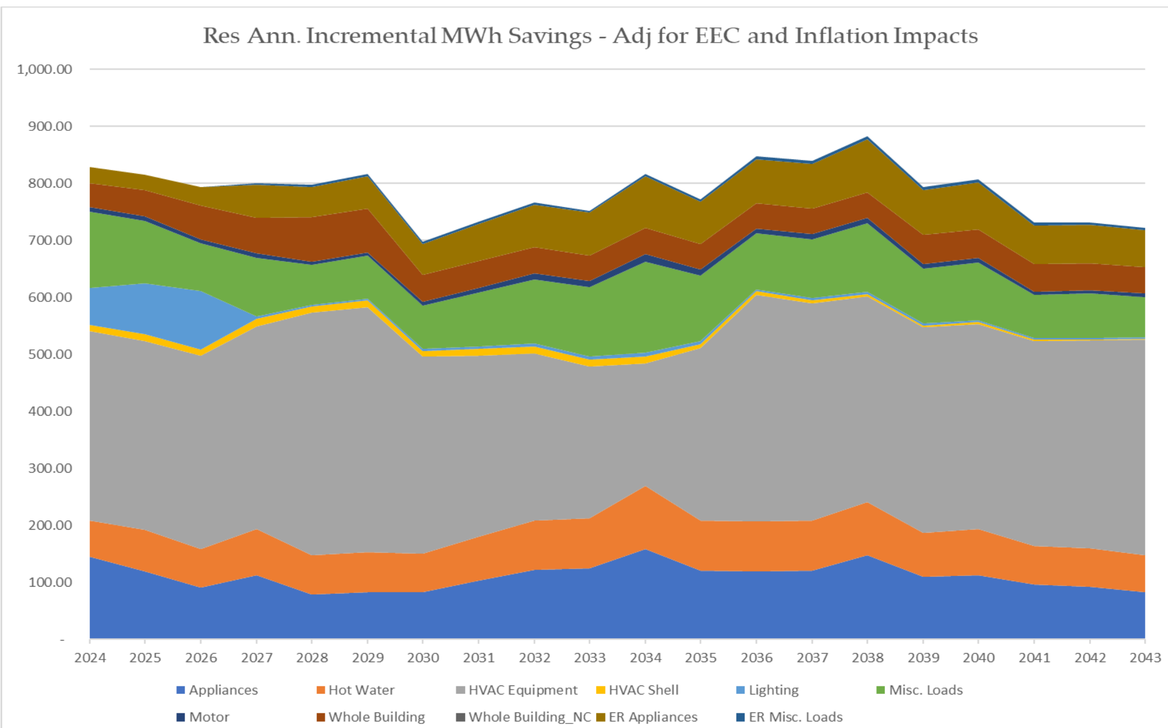


[52] Arguably such measures may be replaced with the then current version of technology resulting in greater cumulative savings than what is shown in the above graph.

As shown in the graph above, lighting opportunities continue to provide a significant pool of cost-effective savings. These savings, however, especially in the outer years, are related to lighting controls and designs, rather than lighting fixtures as in the past. In the short term, commercial lighting savings will be generated from a temporary initiative to encourage businesses to replace their four-foot linear fluorescent fixtures earlier than they might have. As noted in Case #22-2954-PET, this opportunity is being pursued by BED and Efficiency Vermont due to the recent passage of legislation banning the sale of linear bulbs containing mercury. Annual savings from heating, cooling, and ventilation motors will also increase modestly over the next several years.

Residential end-use savings will likely be generated from the installation of more advanced heat pumps and other weatherization opportunities, as shown in Figure 4-8.

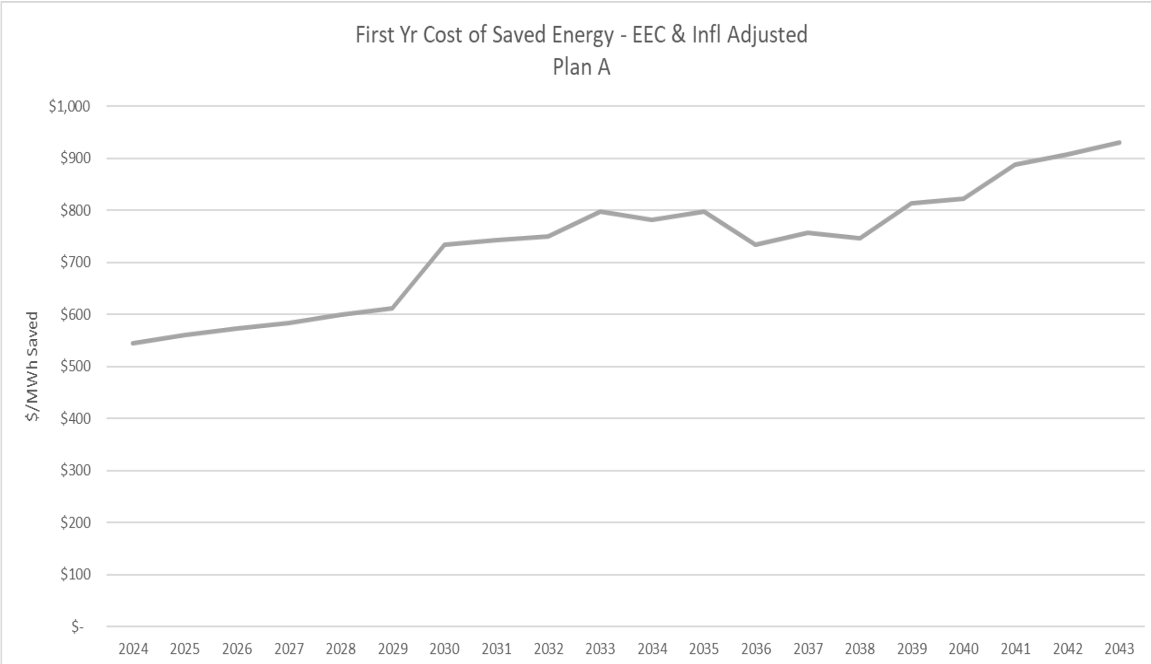
Figure 4-8: Forecast Residential EEU MWh Savings, Adjusted, 2024-2043



Finally, the first-year cost of saved energy is expected to increase over time as less expensive savings (from lighting, for example) are depleted, as shown in

Figure 4-9.

Figure 4-9: Forecast EEU First-Year Cost of Saved Energy, Adjusted, 2024-2043



The first-year cost of saved energy historically has been between $300/MWh and $400/MWh. Even though the cost of saved energy is rising, as expected, the levelized cost of saved energy seems generally to compare favorably with the expected future costs of renewable energy.

Beneficial Electrification

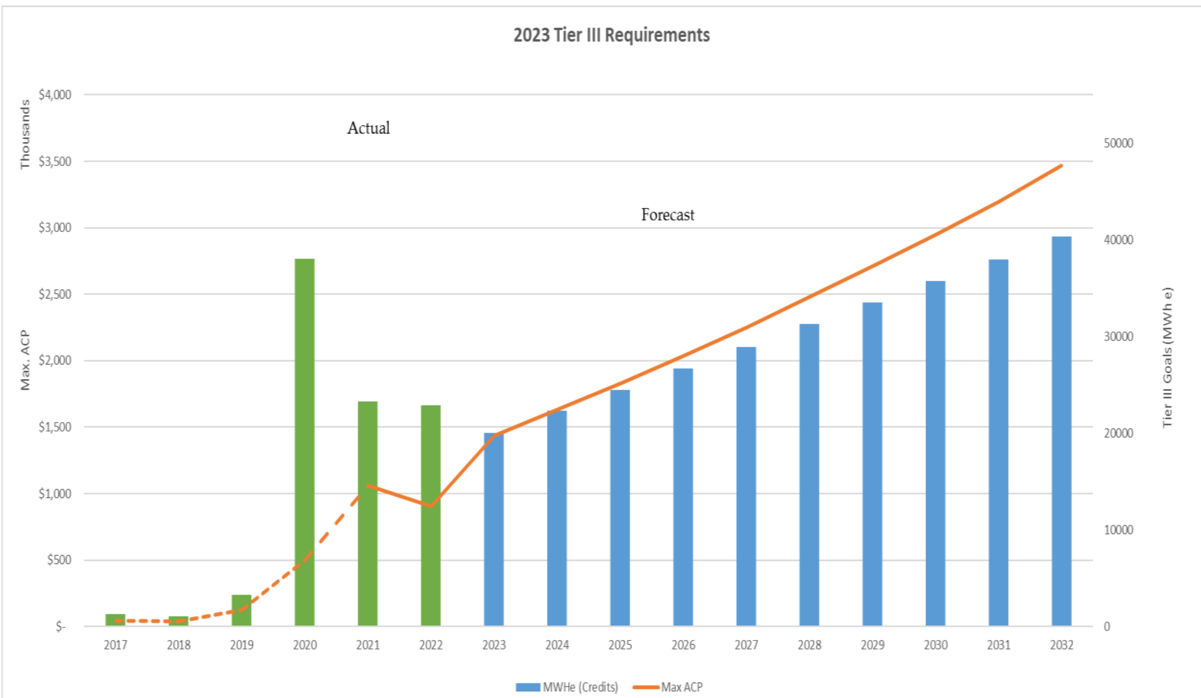
In accordance with 30 V.S.A. § 8005(a)(3), referred to as Tier III of the Vermont renewable energy standard ("RES"), BED actively encourages its customers to reduce fossil fuel consumption by supporting and implementing a host of beneficial electrification programs. BED's current Tier III programs include the following measures:

- All electric in plug-in electric vehicles
- Workplace electric vehicle chargers
- Multi-family electric vehicle chargers
- BED-owned electric vehicle chargers
- Electric public transit buses
- Advanced cold climate heat pumps, including ductless cold climate heat pumps, centrally ducted heat pumps and geothermal heat pumps
- Electric bicycles
- Electric lawn appliances

Through these programs, BED annually generates increasing amounts of Tier III credits by offering incentives directly to customers to purchase an electric vehicle or cold climate heat pump, for example, rather than traditional fossil-fuel–burning equipment. Each beneficial electrification measure is worth a pre-established number of credits equal to the amount carbon emissions avoided by the measure. BED's overarching goal in implementing its beneficial electrification programs is to transform the transportation and space heating markets so that new, non–fossil-fuel–burning efficient technologies become the norm.

Figure 4- 10 compares BED's past Tier III results to future Tier III obligations. Since 2020, BED has exceeded its annual obligation and has accumulated 26,705 Tier III credits as of 2022. Although accumulated credits can be applied to our Tier III obligations in the future, BED is not planning to do so. Instead, BED remains committed to fully funding its beneficial electrification programs to support the City's strategic objective to become an NZE community.

Figure 4-10: Tier III Program Actual and Forecast Activity, 2017-2032



BED's investment in its beneficial electrification programs doubled from $500,000 in 2020 to $1 million in 2021. In 2022, Tier III spending amounted to approximately $971,000. Going forward, Tier III compliance costs are projected to increase from $1.5 million to $3.5 million annually. However, BED believes that while program costs—in the aggregate—may need to increase as the cost of measures increase, BED may lower some customer incentives as other sources of economic support are made available to customers. For example, the federal government's commitment to increase tax credits to U.S. consumers through the Inflation Reduction Act ("IRA") for heat pumps, electric vehicles, and electric vehicle chargers will help consumers transition from traditional fossil fuel–driven equipment to beneficial electrification measures.

BED's Tier III costs are financed through General Obligation bonds issued annually. As BED creates Tier III credits through its program activities, BED tracks these credits in "inventory." Each month, BED expenses the credits required to meet its obligation from those held in inventory based on average inventory cost at that time. Such financing and expensing of Tier III credits permits the use of bond funds and allows BED to exceed its obligation in a period without income statement impacts.

In the section below, we evaluate further the historical and potential future impacts of BED's major beneficial electrification programs on the grid and its purchased power obligations. We also discuss how increasing levels of Tier III adoption may impact MWh sales and peak demand for power during the summer and winter seasons. Finally, this section briefly addresses the results of our cost-effectiveness tests, as required under 30 V.S.A. § 218c and PUC Rule 4.410, Cost-Effectiveness Screening of Energy Transformation Projects.

As mentioned in Chapter 1, our analyses below quantify the potential impact of each of the major beneficial electrification measures under the base case scenario as well as high and low cases. The base case scenario assumes current adoption trends of Tier III measures will continue to increase steadily but modestly into the future. The low case scenario assumes current trends falter slightly due to any number of reasons. Under the high case scenario, we assume that the City of Burlington nearly reaches its NZE goals by 2042 in the transportation and residential (only) thermal heating sectors. The high case scenario assumes stable-to-improving economic conditions, continued federal and state financial support and, a growing acknowledgement of the connections between human-generated carbon emissions and severe climate disruptions.

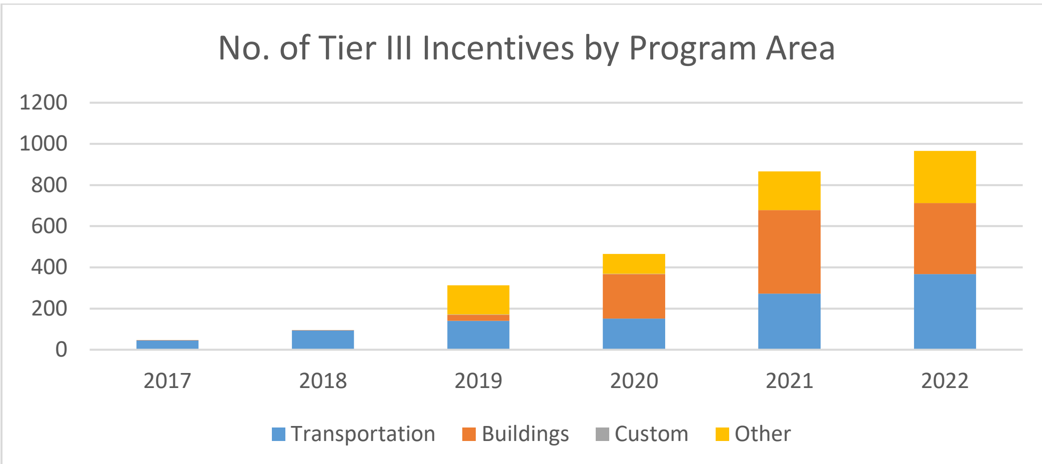
Regarding commercial sector electrification, it is important to note that electrification of building space heating and cooking was omitted from the high case scenario. This omission was intentional and was the subject of significant discussion with PSD staff.[53] In the absence of regulatory mandates requiring existing commercial buildings to reduce their carbon footprint and/or rate design programs that create electric price advantages (over natural gas), BED believes that widespread electrification of the commercial sector would be highly improbable within the current planning horizon (i.e., 2042). BED will revisit this assumption in subsequent IRPs and adjust its future long-term resource plans accordingly. BED also will continue to actively seek custom projects to assist commercial customers with transitioning from fossil gas heating to either renewably sourced advanced heat pumps with renewable gas as a backup heating solution and/or district heat alternatives.

[53] Although electrification of space heating and cooking has been included in the base case scenario (i.e., embedded within the end-use saturation model), the amount of such loads is relatively de minimis.

Historical Tier III Activity

Since June 2020, the number of BED Tier III program incentives has doubled. There are several plausible explanations for this increase, including federal government economic stimulus checks, federal and state income tax benefits, BED customer incentives, growing concerns over climate change, and improving technologies.

Figure 4-11: Annual Tier III Incentives by Program Area



BED believes that in order to sustain historical Tier III program activity trends into the future, it will need to continue providing financial support in the form of customer rebates and technical assistance.

Table 4-2 highlights the type and dollar amount of incentives BED customers can currently access in 2023.

Table 4-2: Current Tier III Incentives

	Tier III Projects	Market Rate Incentive	Income eligible enhancement	EEU	ACT 151 incentives	Total Max Customer Incentive
Transportation	New AEV	$ 1,800	$ 700	$ -	$ 500	$ 3,000
	New PHEV	$ 1,500	$ 300	$ -	$ 500	$ 2,300
	PreOwn AEV	$ 800	$ 200	$ -	$ 500	$ 1,500
	PreOwn PHEV	$ 800	$ 200	$ -	$ 500	$ 1,500
	EVSE (home)NEW or preOwned AEV only	$ 400	$ -	$ -	$ 500	$ 900
	EVSE (home)NEW or preOwned PhEV onl	$ 200	$ -	$ -	$ 500	$ 700
	BED owned EV Chargers	$ -	$ -	$ -	$ -	$ -
	Level 2 - Workplace EV Charger, per port	$ 2,000	$ -	$ -	$ -	$ 2,000
	Level 3 - Workplace EV Charger, per system	$ 10,000	$ -	$ -	$ -	$ 10,000
	SemiPublic MF Chargers (level 2)	$ 100	$ -	$ -	$ 500	$ 600
	E Bikes (customer)(3)	$ 200	$ -	$ -	$ -	$ 200
	E Motorcycle	$ 500	$ -	$ -	$ -	$ 500
Bldgs	ccHP,less than 2tons (1)	$ 1,100	$ 400	$ 350	$ 1,000	$ 2,850
	ccHP,2tons+	$ 2,000	$ 400	$ 450	$ 500	$ 3,350
	ccHP (2nd unit)	$ 250	$ -	$ 350	$ 250	$ 850
	HPWH Tier 1&2	$ 500	$ 200	$ -	$ 300	$ 1,000
	HPWH Tier 3&4	$ 800	$ 200	$ -	$ 600	$ 1,600
	Hi Perf CDHP < 2 Tons (Res)	$ 2,000	$ 400	$ -	$ 250	$ 2,650
	Hi Perf. CDHP 2-4ton (Res)	$ 4,000	$ 400	$ -	$ 250	$ 4,650
	Hi Perf. CDHP 4+ Ton (Res)	$ 6,000	$ 400	$ -	$ 250	$ 6,650
	Std. CDHP < 2 Tons (Res)	$ 1,000	$ 400	$ -	$ 250	$ 1,650
	Std. CDHP 2-4ton (Res)	$ 2,000	$ 400	$ -	$ 250	$ 2,650
	Std. CDHP 4+ Ton (Res)	$ 3,000	$ 400	$ -	$ 250	$ 3,650
	ERV/HRV Tier 1	$ 500	$ 300	$ -	$ 250	$ 1,050
	ERV/HRV Tier 2	$ 700	$ 300	$ -	$ 250	$ 1,250
	AWHP per ton (Res)	$ 2,000	$ 400	$ -	$ 600	$ 3,000
	AWHP per ton (Com)	$ 2,000	$ -	$ -	$ 800	$ 2,800
	Integrated Controls (pilot)	$ 300	$ -	$ -	$ -	$ 300

As the table above highlights, customer incentives are funded through various regulatory mechanisms, including 30 V.S.A §8005; 30 V.S.A §209 and Act 44 of 2023. The combination of these funding mechanisms allows customers to stack multiple incentives together, which has been instrumental to BED's success in launching impactful programs that advance BED's NZE goals and meet Tier III requirements. Stacked incentives in combination with existing and future federal tax credits increase the cost-competitiveness of beneficial electrification measures relative to traditional measures. However, to achieve its proportional share of Vermont's Tier III requirements by 2050, BED will need to ramp up program aggregate spending over the next several years.

Tier III Program Cost-Effectiveness Testing

To estimate the cost-effectiveness of our Tier III programs, BED used a "mini-model" evaluation tool to assess the range of plausible net benefits and costs that the beneficial electrification measures will generate over the IRP planning horizon. The main purpose for conducting the mini-model analyses were to:

- Continue to monitor the customer economics of the major beneficial electrification technology options; and,
- Continue to monitor the economic value of these technologies to BED and society at large.

The results of these analyses helped to inform our forecasts of customer adoption, which in turn indicate, at least directionally, the rate of growth in electric loads and peak demand we will need to serve over time.

While each technology evaluated below is unique, the outputs of each mini-model share a common structure and methodology. Each section begins with a brief introduction and review of the key assumptions that were used in our cost-effectiveness models. The report then summarizes plausible customer impacts, the utility cost test ("UCT"), and societal cost test ("SCT") results for each of the technologies. In addition, this portion of the report assesses the potential MWh sales impacts of each technology on BED's resource requirements, Tier III incentive costs, greenhouse gas ("GHG") emissions reductions, and Tier III credits.

Customer Impact Test

The customer impact test compares the differential cost to the customer of beneficial electrification technologies vs. fossil fuel technologies. For example, this test compares the incremental upfront capital cost (i.e., purchase price) of an electric vehicle with the purchase price of a traditional light-duty vehicle that the customer otherwise would have purchased *but for* BED's incentive. Unlike the societal cost test, the customer incentive is considered a direct benefit to the customer and thus reduces the cost of the electric vehicle.[54] Federal and state income taxes, if applicable, are also considered a customer benefit and act to reduce the purchase price of the electric vehicle vis-à-vis a light duty vehicle.

Although BED recognizes that a growing number of households participating in our Tier III programs are discovering that they need to upgrade their electric service panel to install an advanced heat pump or electric vehicle charger, this evaluation does not include this additional capital cost. BED omitted this cost because it is unclear whether the number of service locations that need to be upgraded (or the cost of such upgrades) would significantly impact our future electric forecasts. For those customers who inquire, BED provides technical support to determine whether electric panel upgrade is necessary and, if so, BED refers those customers to one of three financial institutions to finance the improvements and to the IRA website to learn about possible tax credits (or potential discounts for income-eligible households).

[54] Under the SCT, the incentive is considered a transfer payment and is therefore excluded from the analysis.

In addition to capital costs, BED factors into its evaluation the operating cost of new beneficial measures. The customer impact test compares the operating cost differentials of the two alternative purchasing decisions. While a customer's electricity costs may increase slightly, their fossil fuel and maintenance costs are lower, thus creating annual savings. Often, such operating savings result in a simple payback of the additional capital costs in three to seven years.

Utility Cost Test

The UTC is intended to demonstrate whether a particular technology produces a net benefit to BED, either through reduced wholesale costs or increased revenues that exceed marginal costs. Increased utility costs flow from incremental power supply costs, inclusive of energy, capacity, transmission, RECs, and ancillary service expenses and the cost of the Tier III incentive. Increased utility revenues are generated from additional retail sales at rates above the incremental cost of wholesale energy.

Whether a measure produces net benefits for BED depends largely on four key variables that are expected to impose the greatest degree of risk on BED's net present value ("NPV") cost of service: the wholesale cost of energy, capacity, and transmission, and the forecasted values for RECs. The values for each applicable variable were grouped together to create a base case scenario, which reflects the mostly likely outcome given our assessment of future wholesale energy, capacity, transmission, ancillary costs, and REC values.

Societal Cost Test

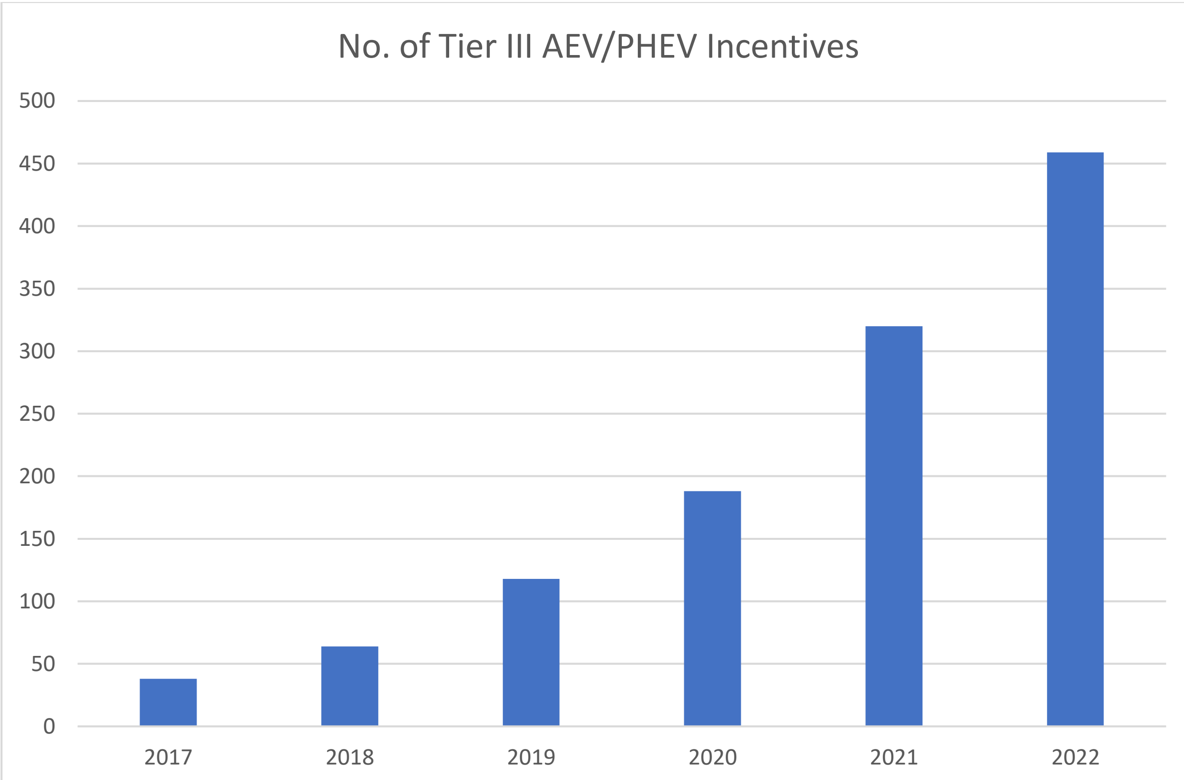
The societal cost test includes utility costs, as well as the costs that society bears such as illnesses caused by pollution, reduced productivity, and climate-related damages. These costs are generally referred to as "externality" costs, or costs that have been attributed to the provision of a service or product that is borne by society at large but is not included in the price of the service or product provided. BED's societal cost test measures the externality costs that are avoided as a result of beneficial electrification measures, such as emissions and other environmental impacts. Externality costs can be avoided by reducing fossil fuel consumption or reducing electricity use generated from a non-renewable source, although BED assumes it will retain its 100% renewable energy mix in this IRP. Reduced societal costs can occur due to actions by either the customer or the utility. For the purposes of this test, BED assumed $125/ton[55] of carbon as an avoided externality cost, which has the effect of increasing the value of beneficial electrification and electric efficiency.

Electric Vehicles ("EVs")

Since its launch in 2017, the number of BED EV program incentives has increased significantly.

[55] 2022 Comprehensive Energy Plan, Department of Public Service.

Figure 4-12: EV Tier III Incentives, 2017-2022



The rate of EV growth in Burlington appears to be tracking closely with increased EV adoption statewide and elsewhere (based on our review of DriveElectric Vermont's periodic reports). We believe this trend will continue as IRA tax incentives and EV-related grants (e.g., manufacturing, battery research and development) become available. Such federal and state support has spurred the auto industry into investing in EV and battery manufacturing in the United States. Consequently, EV product lines seem to be expanding, inventories seem to be increasing, and consumer prices are stabilizing at relatively lower levels than during the COVID years when EV supplies were severely limited.

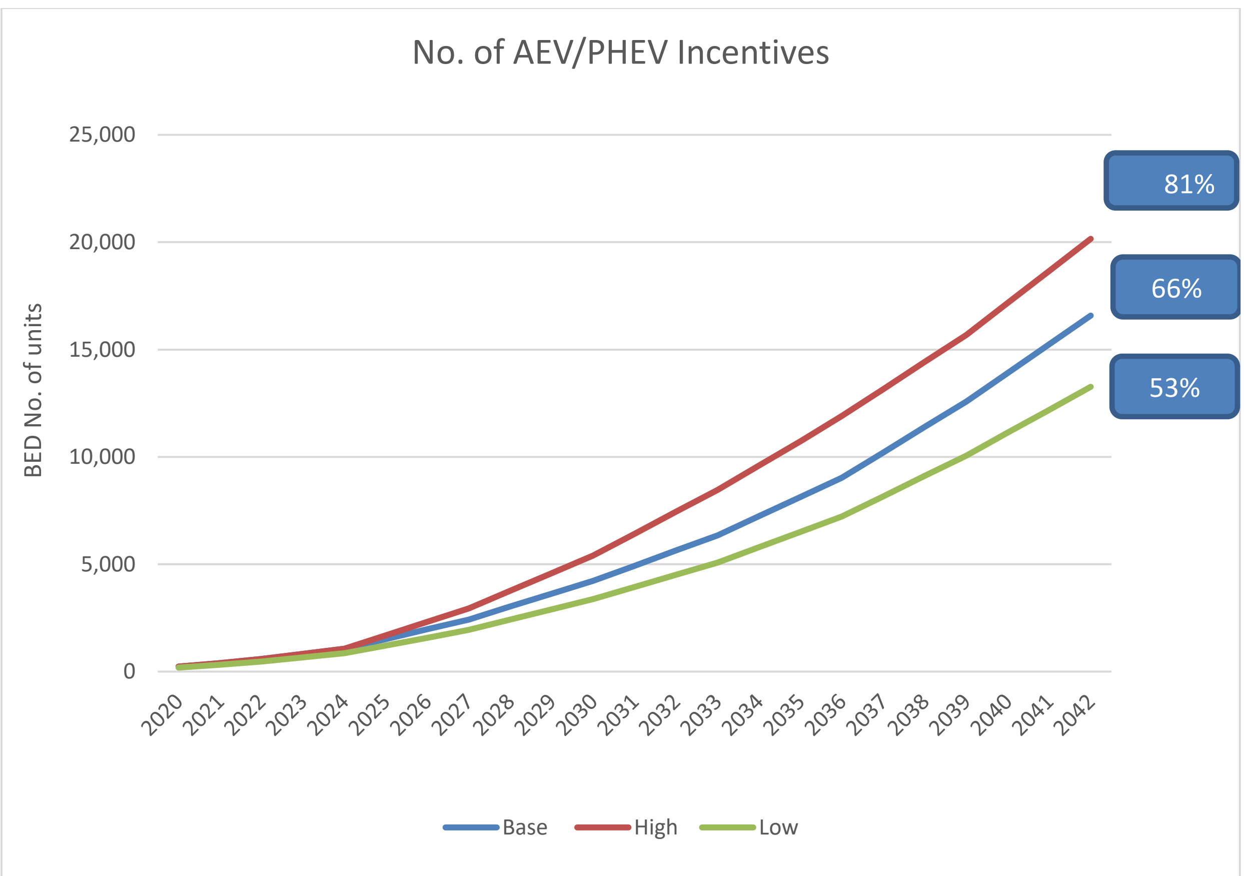
Nonetheless, BED believes that sustaining the rate of EV growth in Burlington, especially over the next several years, will require continued financial support. As such, BED intends to keep in place its existing incentive structure at this time.

Table 4-3: BED EV Incentives

	Market Rate Incentive	Income eligible enhancement	ACT 151 incentives	Total Incentive (Max)
New AEV	$ 1,800	$ 700	$ 500	$ 3,000
New PHEV	$ 1,500	$ 300	$ 500	$ 2,300
Preowned AEV	$ 800	$ 200	$ 500	$ 1,500
Preowned PHEV	$ 800	$ 200	$ 500	$ 1,500

BED believes that given Vermont's focus on climate solutions, the number of EVs registered in Burlington will continue to increase over time. For the purposes of this IRP, as well as ensuring that we comply with Vermont's resource adequacy requirements pursuant to 30 V.S.A. § 218c and RES, BED developed the following EV unit forecasts shown in Figure 4-13.

Figure 4-13: Projected EV Incentives—Low, Base, and High Cases



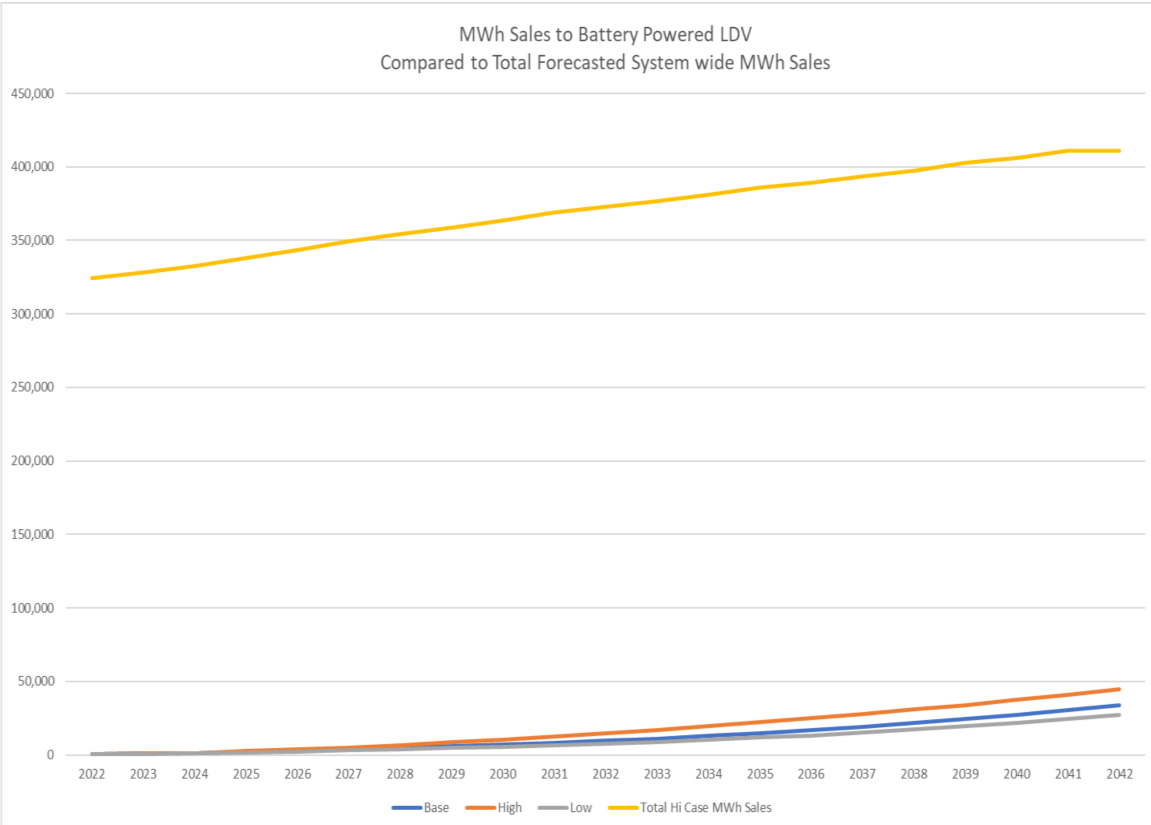
Under the base case scenario, BED assumes that current Tier III incentive rates will continue at a relatively constant rate. At this growth rate, we anticipate that roughly 66% of light-duty vehicles ("LDVs") registered in the City will be battery-powered.[56] Under the high case scenario, BED's model shows that EV adoption will accelerate at a more rapid pace, reaching around 81% market share of all LDVs registered in the City. The more aggressive pace assumes EV prices continue to decrease, albeit more slowly, as battery prices decline, EV production and product choices increase, and more EV chargers are deployed. Under the low case scenario, EV adoption falters slightly mostly because the assumed deteriorating economic conditions and higher unemployment levels dissuade consumers from making the transition to all-electric vehicles ("AEVs"). Under this scenario, just over half of the LDVs registered in the City will be battery-powered.

As shown in

Figure 4-14, with an increasing number of EVs charging in the City, MWh sales will increase across all scenarios over time. Estimated annual MWh sales increase to approximately 44,000 MWhs in 2042 under the high case scenario, about 10,000 MWhs more than our base case assumption. This increase in EV-related MWh sales amounts to approximately 10% of total system-wide MWh sales by 2042.

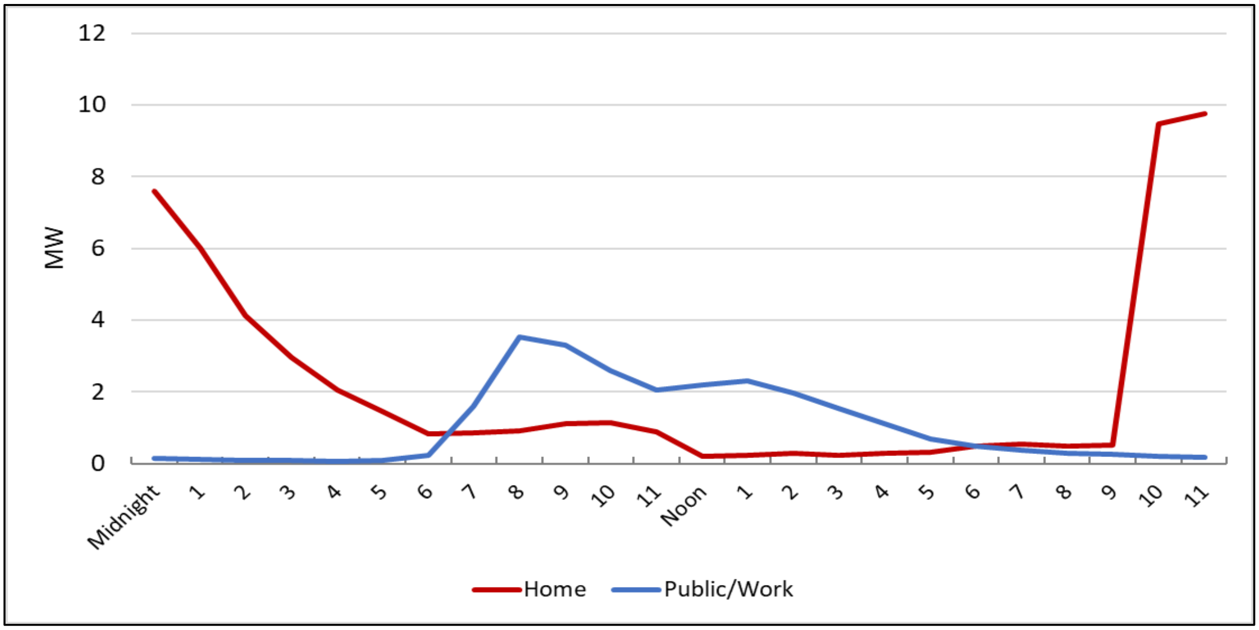
Figure 4-14: Forecasted MWh Sales to Battery-Powered Light-Duty Vehicles Compared to Total MWh Sales

[56] We anticipate that approximately 25,000 LDVs will be registered in Burlington by 2042.



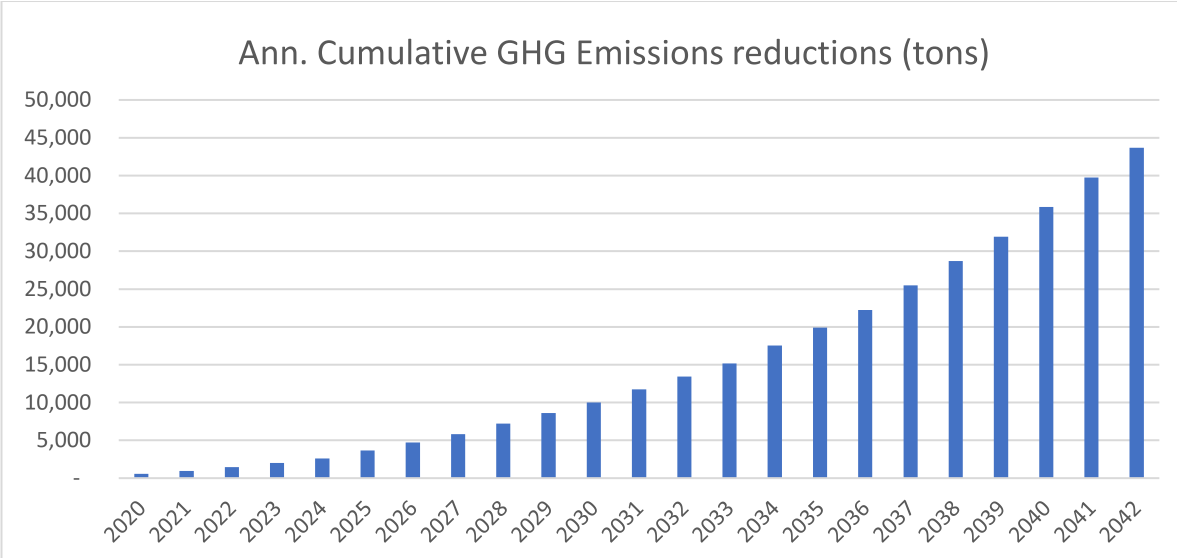
In terms of daily EV-related load profiles, roughly 80% of the estimated EV load increase will occur during off-peak periods due to our EV rate credit program. This program is designed to encourage participating customers to charge their vehicles after 10 pm. As shown in Figure 4-15 below, BED's EV rate credit program shifts a considerable amount of the EV-related loads to the late-night hours when aggregate system-wide loads are at their lowest.

Figure 4-15: Home EV Charging Load Profile vs Public/Workplace EV Charging Load Profile



Given the expected EV-related load growth under the three scenarios, as well the off-peak charging characteristics, BED expects it will be well positioned to cost-effectively serve these increased loads with existing and future renewable energy supplies through the current planning period. Moreover, under the base case scenario, BED anticipates LDV emissions would be lowered by as much as 45,000 metric tons annually by 2042.

Figure 4-16: Projected Cumulative GHG Emissions Reductions from EV Deployment, 2020-2042



Major Assumptions and Inputs

To model the cost-effectiveness of AEVs, BED relied on the major inputs and assumptions shown in

Table 4-4. Importantly, the incremental cost of an AEV differs from the current Tier III technical advisory group ("TAG") estimates of $15,700. The TAG's incremental cost estimate was based on a 2018 analysis of a limited set of AEVs. Since 2018, several additional models have been introduced into the market and prices are beginning to decline as manufacturers recover from pandemic-induced supply chain disruptions.

Table 4-4: AEV Cost-Effectiveness Assumptions

	Major Inputs - AEV	Cost/Benefits	Source
Customer	Est. Incremental Costs[57]	$ 9,340	[2022 US DOE]
	Op Savings (fuel & maint. expenses)	$ 9,631	TAG
	Measure Life (in service)[58]	12	BED
	Annual Miles Driven	8,000	NZE Roadmap
BED	Increased kWH Sales	2,367	BED
	Net Revenue	$ 1,650	BED
	Tier III Costs	$ 1,691	BED
	Tier III Credits	39.7	TAG
	Net MWh e Costs (benefit)	$ 1.02	Calculated
VT	GHG emissions reductions (tons)	3	TAG

BED's incremental cost estimates are based on a 2022 U.S. Department of Energy report indicating that the manufacturers' suggested retail prices of EVs are lower than the TAG's older estimate. BED's incremental upfront costs were derived on a weighted average basis, as shown in Table 4-5.

Table 4-5: Incremental Cost of EVs vs. non-EVs

Incremental cost of EV relative to comparable ICE vehicles					
	AEV	PHEV	Weighted 80/20 AEV/PHEV	Weight by Type	
Compact	$ 7,500	$ 7,000	$ 7,400	50%	$ 3,700
Midsize	$ 8,500	$ 8,000	$ 8,400	25%	$ 2,100
SUV	$ 14,000	$ 9,500	$ 13,100	20%	$ 2,620
Pick Ups	$ 19,500	$ 14,000	$ 18,400	5%	$ 920
				Weighted average Incremental EV cost	$ 9,340

Customer Impact Test

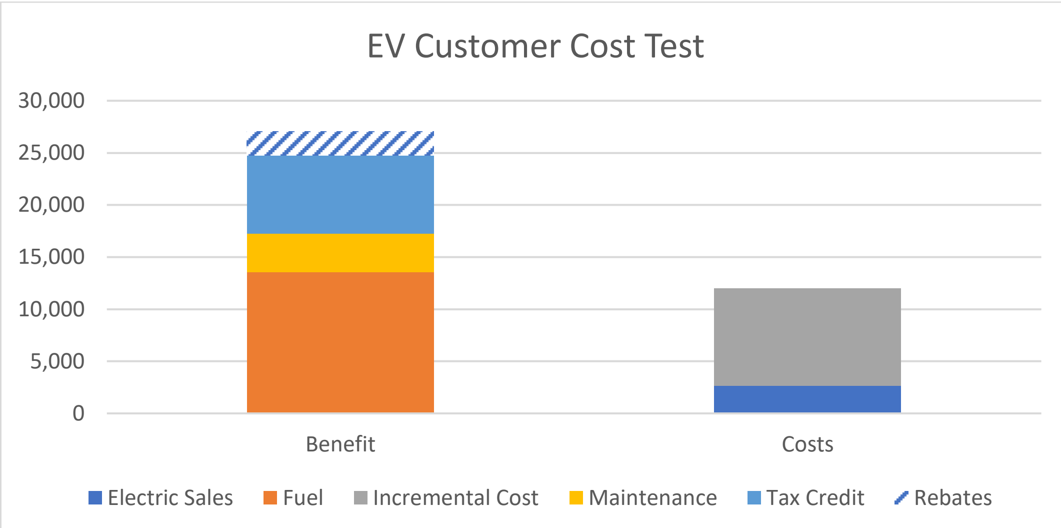
As shown in Figure 4-17, owning an AEV results in significant customer net savings (benefits) of approximately $15,000 over the vehicle's 12-year life. Such savings are derived from a federal

[57] BED's incremental AEV costs differs from the Tier III TAG estimates of $15,700, which was last updated in 2018.

[58] Although the Tier III TAG assumes that new AEVs have an 8-year measure life for the purpose of calculating credits and a 4-year measure life for preowned AEVs, BED believes that AEVs will likely remain in service for up to 12 years as either a new or preowned vehicle for one household or another.

tax credit ($7500), local utility rebates (between $2300 and $3000 per vehicle) depending on eligibility,[59] fuel ($350/year), and maintenance ($308/year). Customer costs include the incremental cost of an AEV ($9,340) and additional electric costs ($770/year) to power the vehicle.

Figure 4-17: EV Customer Cost Test Results



Assuming a customer is eligible for, and takes advantage of, the federal tax credit, as well as participates in BED's Tier III programs (rebate and EV rate credit), AEVs are comparable in costs to fossil-fuel vehicles. The more customers become aware of how cost competitive AEVs have become, the more likely Vermont's transportation market will transform into an electrically driven marketplace, which is an essential condition for the state to reach its GHG reduction requirements.

Utility Cost Test

For BED, the current AEV program results in negative utility benefits under all scenarios at the existing level of distribution utility-only rebates offered to customers ($1800 market rate, plus 15% overhead costs). Net utility costs per AEV range between $778 (low case) to $2200 (high case). Average benefits from incremental MWh sales amount to $2800 (over 12 years) per vehicle, assuming 80% of EV owners participate in BED's EV rate credit program. Net Present Value (NPV) base case utility costs include transmission ($260), capacity ($54), energy ($1479), ancillary ($83), incremental RECs ($114), and Tier III incentives ($2070, including administrative costs).

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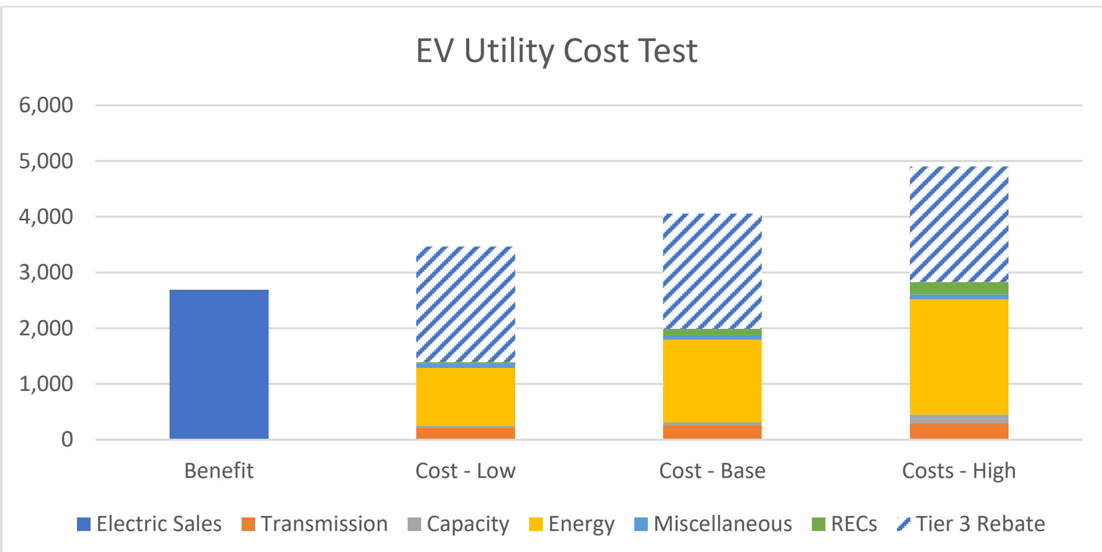
[59] Inclusive of Act 151 rebate of $500 per AEV. Please note that Act 151 rebate costs are not considered in the UCT, as such funds are generated from the EEC, not retail rates.

Although UTC results suggest that the AEV program should be revised, BED intends to keep existing terms and conditions in effect for the time being. Our decision is based on the results of our societal cost test results, as further described below, which demonstrate that our existing program is yielding substantial net benefits. BED believes that Vermont's EV market needs additional time to mature and grow. Keeping our current rebates in place will help to sustain, and maybe accelerate, EV growth rates. When 15% to 20% of new car sales are EVs, BED may re-consider its program design features, which may include lowering rebates or decreasing the EV rate credit. Additionally, BED believes that continuing to provide strong rebates for EVs is warranted as the net cost of the program is lower ($1 to $2 per MWhe) than the alternative, which is to pay the alternative compliance payment ("ACP") of $71/MWhe.

Figure 4-18: EV Utility Cost Test Results



Societal Cost Test

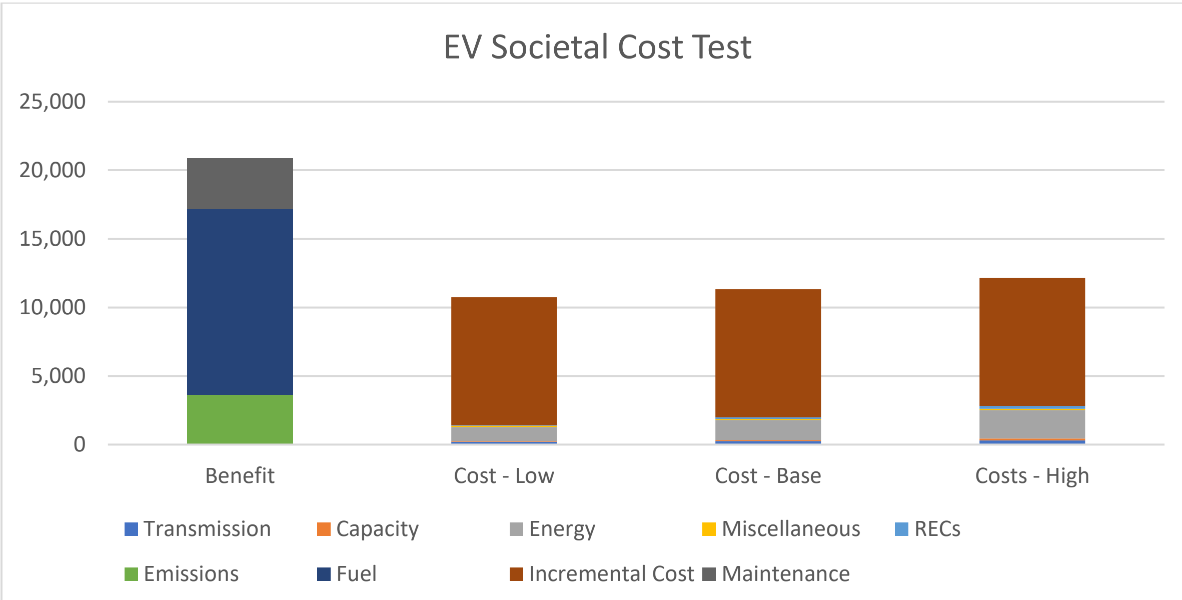
Under the SCT parameters, AEVs produce positive net societal benefits of approximately $9,550 over 12 years under the base case. Net benefits have improved since BED's 2020 IRP analyses largely due to lower incremental capital costs (as described above) and higher avoided carbon cost benefits set at $125/ton. Since 2020, the incremental cost of AEVs has dropped from approximately $15,700 to $9,340 according to a 2022 U.S. Department of Energy report.[60]

Benefits are comprised of emission benefits ($3,637), fuel savings ($13,543), and maintenance savings ($3,704). Meanwhile, NPV costs include transmission ($260), capacity ($36), energy ($1,479), ancillary ($83), RECs ($114), and incremental costs ($9,340). Unlike the customer and utility cost tests noted above, incentives such as the federal tax credit and utility rebate are

[60] 2022 U.S. Department of Energy, Office of Energy Efficiency & RE Energy, 2022 Incremental Purchase Cost Methodology and Results for Clean Vehicles, Dec. 2022.

considered to be transfer payments from one group of customers to another; thus, incentive payments are not included in the SCT.

Figure 4-19: EV Societal Cost Test Results



Conclusions and Course of Action

Transportation is tied with the thermal energy sector for contributing the most GHG emissions in Vermont and is the second-largest source of emissions in the City. Accordingly, BED will continue to support this program for the next several years, even though NPV utility costs exceed benefits. Sustained support at current levels is warranted since it is imperative that Vermonters transition to EVs in order for the state and the City to reach its climate goals/requirements. As EV prices decrease over time and EVSEs become more accessible, BED will likely reduce its market rate incentives to improve its UTC results.

Electric Buses

Green Mountain Transit ("GMT") is the region's public transit authority providing transportation services in Chittenden, Franklin, Washington, and Addison counties. The organization operates and maintains a fleet of 72 diesel-powered buses. On average, a diesel bus travels between 20,000 to 30,000 miles annually and consumes roughly 6,500 gallons of diesel. Annually, GHG emissions amount to 54 tons per year, per diesel bus.

To reduce its carbon footprint, GMT is working to transitioning its diesel fleet to more efficient, cleaner electrically powered buses ("e-buses") over the next decade. The transition started in February 2020 with the delivery of two 40-foot, Proterra electric buses. During the first quarter of 2024, GMT expects to put into service another five e-buses manufactured by New Flyer, Inc.

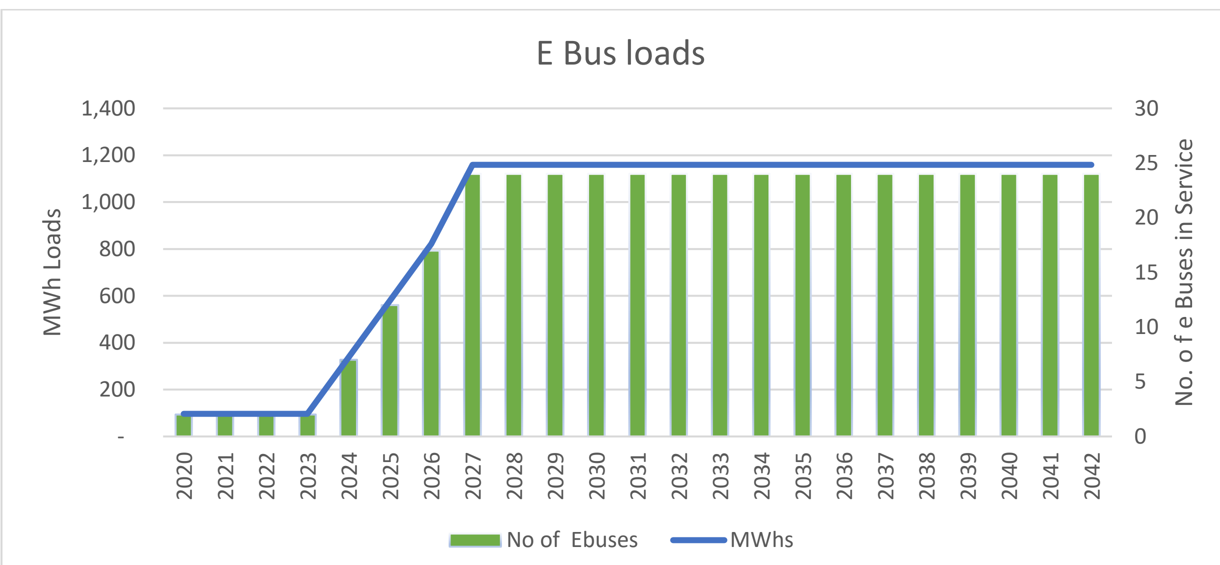
Thereafter, 17 additional e-buses will be integrated into GMT's fleet by 2027.[61] Each round of e-bus procurements have been funded with federal grants, Vermont matching funds, and BED incentives.

Table 4-6: GMT E-Bus Adoption

Year of acceptance	No. of e-buses in fleet
CY2020	2
CY 2024	7
CY2025	12
CY2026	17
CY2027	24

According to GMT, each e-bus is expected to travel approximately 25,000 miles annually. Assuming an e-bus can attain an efficiency of 1.84 miles per kWh, each will consume as much as 48.3-50 MWh (including EVSE losses of 5.0%), displacing approximately 4,902 diesel gallons.[62] If the expected number of e-buses are put into service per the current timeline, BED anticipates that e-bus loads may increase to around 1200 MWh annually, as shown inFigure 4-20 below.

Figure 4-20: Projected E-Bus MWh Sales, 2020-2042

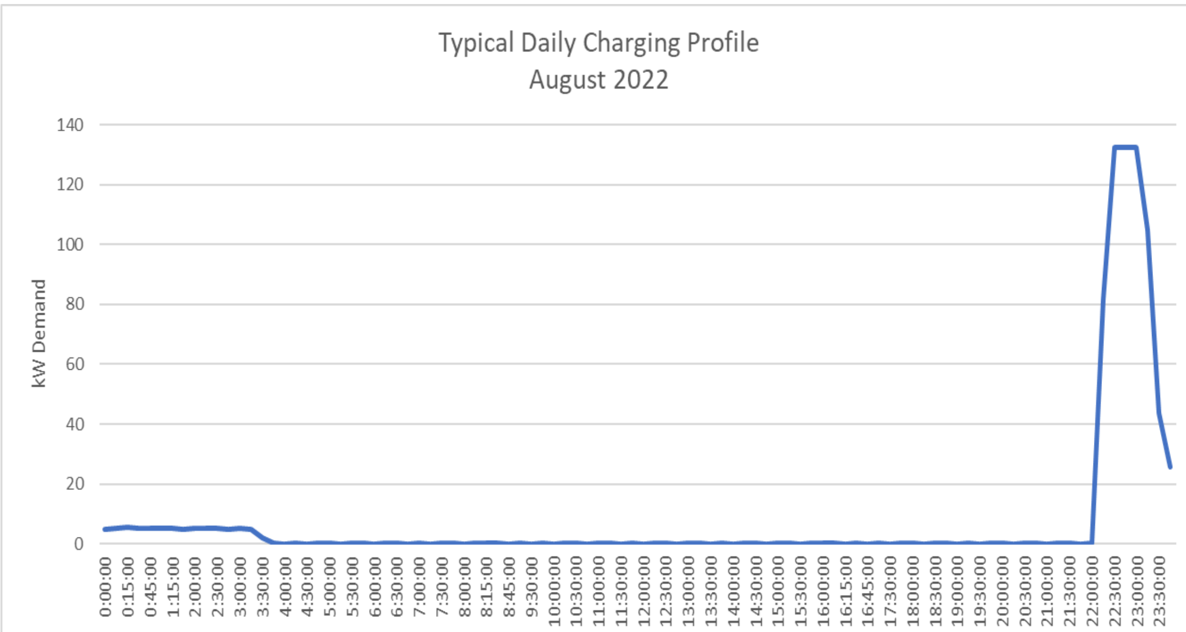


[61] Should GMT integrate even more e-buses over time than they have reported to BED as of Spring 2023, BED will update its e-bus analyses in subsequent IRPs.

[62] Newer diesel buses achieve more miles per gallon than the average diesel bus in GMT's fleet. Thus, the diesel savings are less for the purposes of assessing the cost-effectiveness of new e-buses compared to new diesel buses.

GMT has informed BED that, in the short term, it will continue to charge e-buses under our existing large customer time of use ("LG TOU") tariff. Over time, however, e-buses' electric service may shift to BED's approved EV rate credit programs, which allow for discounted electric rates so long as charging occurs during off-peak demand periods. As a consequence, we do not expect GMT's e-bus loads to change, even as new e-buses are integrated into their bus fleet. At present, GMT's charging profile for the existing two e-buses is illustrated in Figure 4-21 below.

Figure 4-21: GMT E-Bus Charging Profile, August 2022

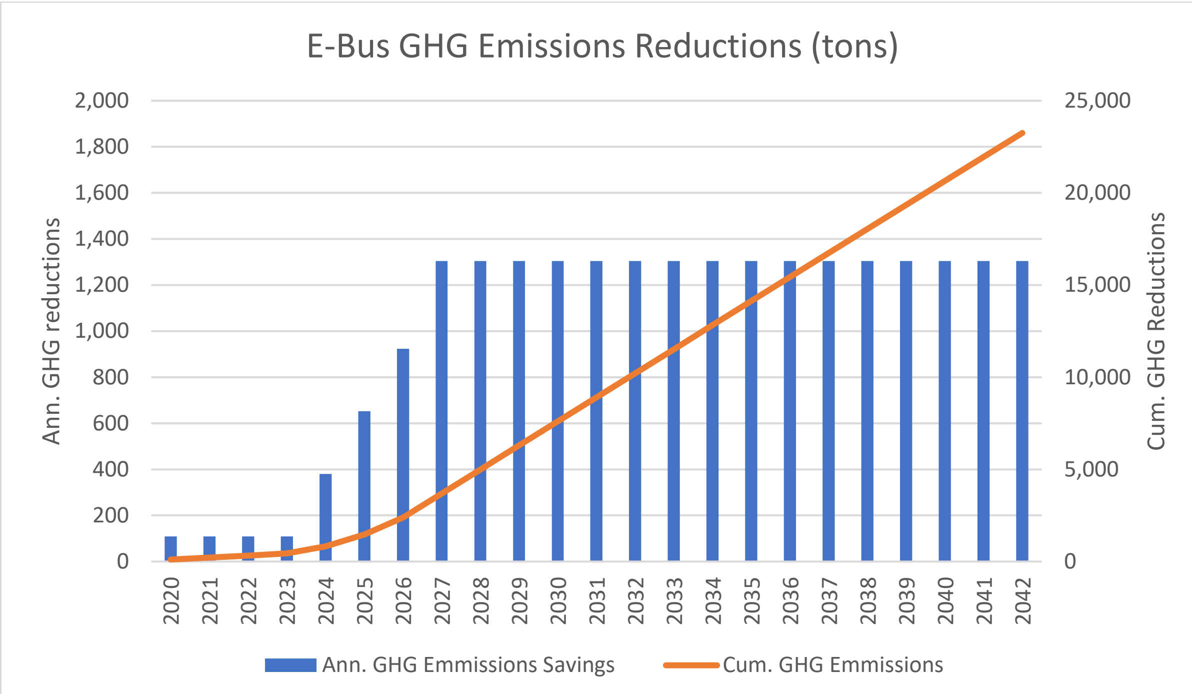


Although we do not expect the e-bus charging load profile to change much with the adoption of new buses in the short term, we do expect total demand to increase from 130 kW to 305kW as the next five buses are put into service. GMT has informed BED that to ensure all seven e-buses are fully powered by 6 am each day, it will need to install three more 60 kW chargers at their main depot located at Queen City Drive. The total maximum demand of the new chargers amounts to 180 kW, which will likely occur between 10 pm and 11:59 am each day of operation. GMT and BED are discussing their charging options in order to accommodate GMT's operational schedules. Such options could include providing electric service to GMT under existing approved EV tariffs, which provide for enhanced charging capabilities and system benefits if GMT can operate its charging equipment in accordance with a pre-determined charging schedule and/or dynamically.

Lastly, if GMT integrates up to 24 e-buses into their fleet, BED expects that GMT's GHG emissions would be lowered by 1,300 tons annually by 2027 as shown in Figure 4-22.

Cumulatively, emissions could be reduced by as much as 23,000 tons, assuming all e-buses remain in service in 2042 (or are replaced with a similar e-bus).

Figure 4-22: Projected GHG Emissions Reductions from E-Bus Deployment



Major Assumptions and Inputs

To model the cost-effectiveness of e-buses, BED relied on the inputs and assumptions shown in

Table 4-7. Incremental costs do not include the cost of EVSEs or electric service upgrades at the bus depot. Such costs are, however, included in the SCT below. These infrastructure costs can be spread over all 24 e-buses GMT is planning to acquire since GMT is future-proofing their facility using federal grant funding to accommodate several more e-buses over time.

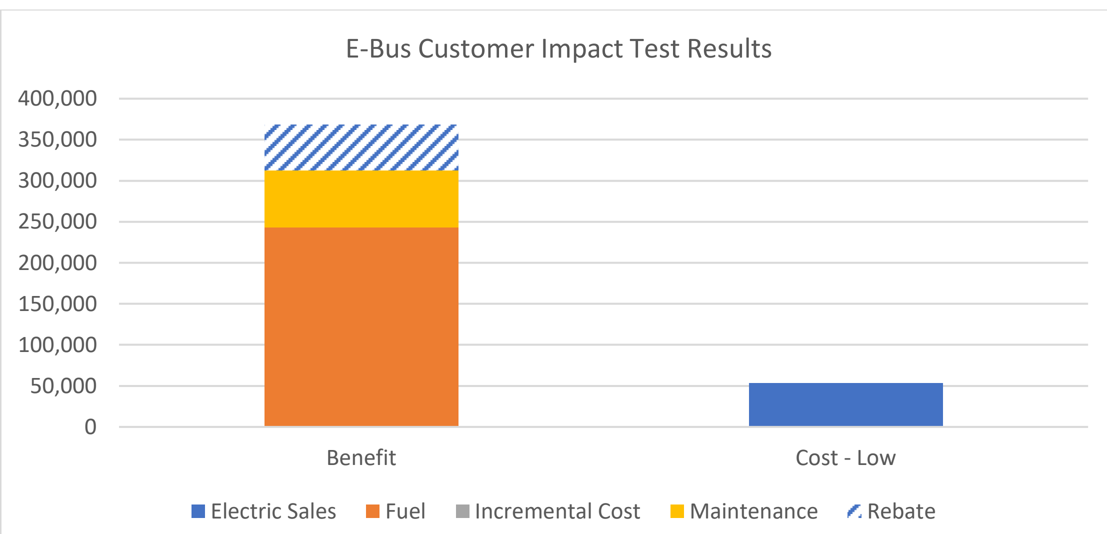
Table 4-7: E-Bus Cost-Effectiveness Assumptions

	Major Inputs - Electric Bus	Cost/ Benefits	Source
Customer	Est. Incremental Costs (80% federal grant funded)	$ 550,000	Fed Grant application
	Fuel Savings	$120,686	BED Calculated
	Maintenance Savings	$70,000	NREL Report
	Measure Life	12	VEIC Memo
	Annual Miles Driven	25,000	VEIC Memo
BED	Increased MWH Sales	48.3	Calculated
	Net Revenue	$50,645	Calculated
	Tier III Costs	$55,000	Est. Calculated
	Tier III Credits	921	TAG
	Net MWh e Costs	$4.73	Calculated
VT	Ann. GHG emissions reductions (tons)	54	Calculated

Customer Impact Test

For GMT, transitioning to an all-electric bus fleet could generate significant operational savings of approximately $315,000 per e-buses over 12 years. Net benefits are largely due to federal, state, and BED grants/rebates, which essentially pay for the entire cost of the new e-bus, as well as charging equipment and electric upgrades. Projected operating savings result from fossil fuels (NPV $243,319) and maintenance (NPV $69,565). Operating savings will be marginally offset by higher electricity costs (NPV $53,000), assuming GMT remains on BED's current LG TOU tariff.

Figure 4-23: E-Bus Customer Impact Test Results

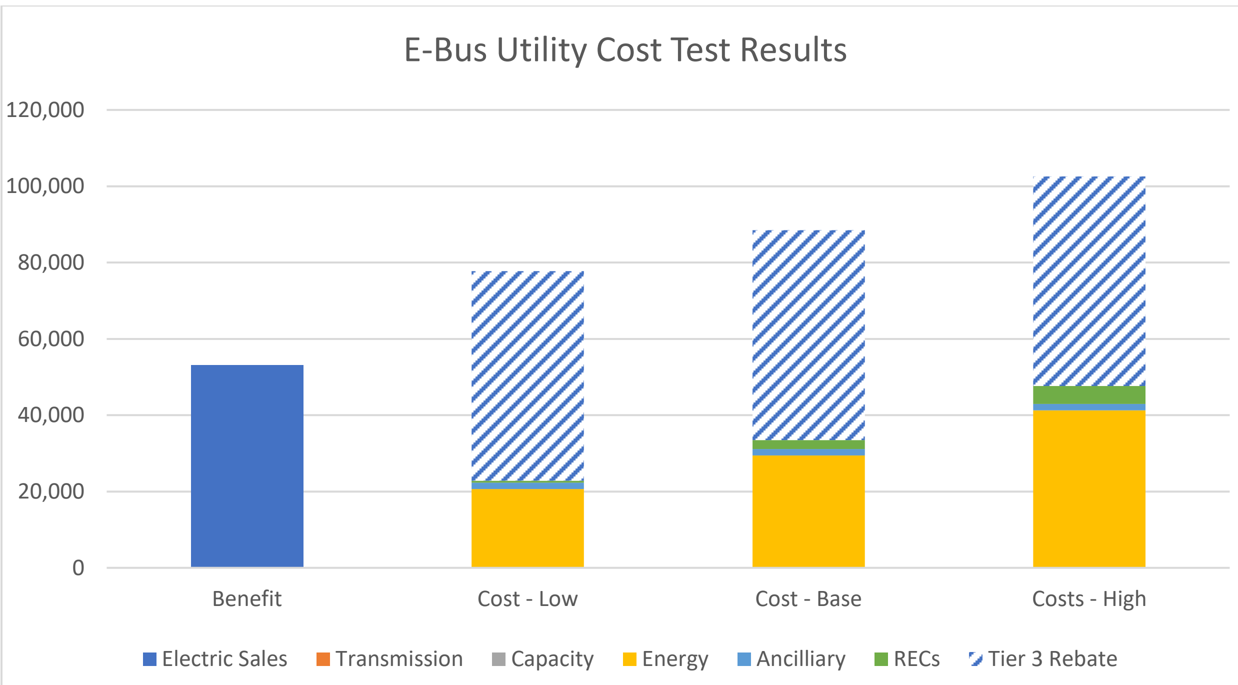


Utility Cost Test

Under all scenarios, providing GMT with a rebate would result in increased net costs for BED ranging from $25,000 to $50,000 over the life of an e-bus. Utility base case costs consist of energy ($29,466), ancillary ($1,694), additional RECs ($2334), and rebates ($55,000). NPV benefits include incremental MWh sales of roughly $50,000 to $55,000 per e-bus.

While offering rebates to GMT appears to be cost-ineffective for BED, we believe that providing strong support to GMT is appropriate for three reasons. First, providing rebates to GMT is less costly ($4.73 MWhe) to BED than paying the ACP ($71/MWhe). Second, many of GMT's riders/customers are of low-to-moderate incomes. Therefore, this program helps BED comply with the Commission's low-income benchmark goals.[63] Third, supporting GMT advances the City's NZE roadmap goals, as well as the State's clean energy policy goals.

Figure 4-24: E-Bus Utility Cost Test Results



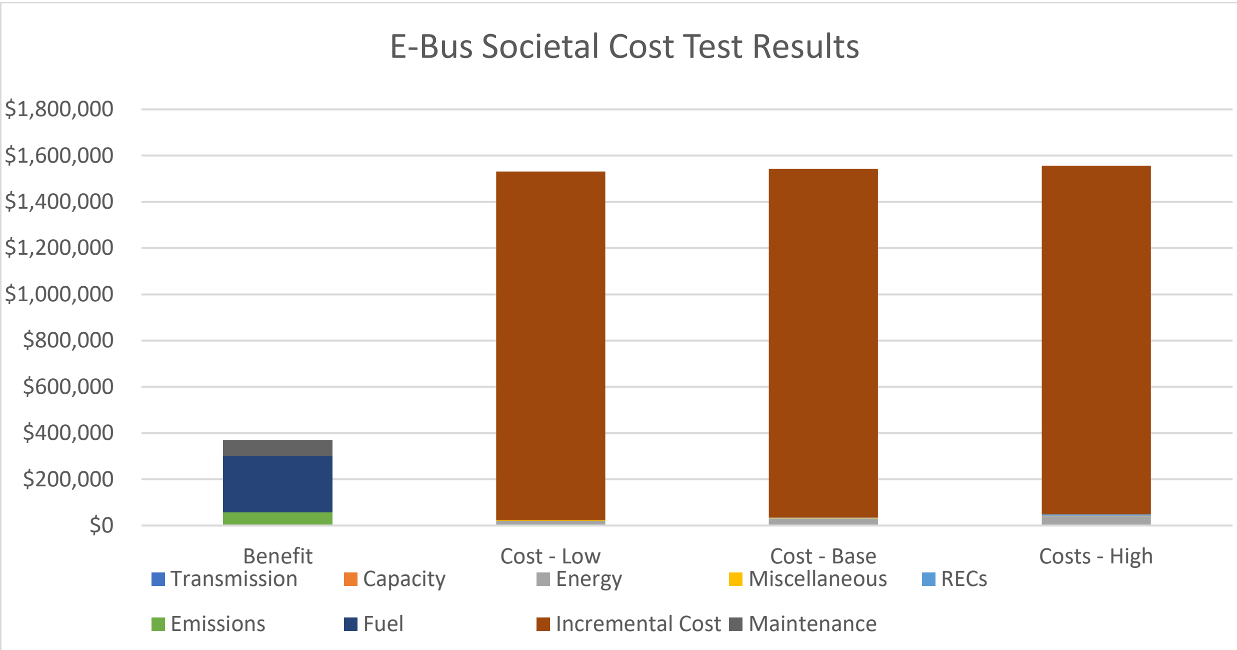
Societal Cost Test

In accordance with SCT protocols, the NPV of e-bus–related costs exceed benefits because of the extraordinarily high upfront capital costs of the e bus, charging equipment, and electrical upgrades, which amount to $1.5 million combined. In total, the NPV of net societal costs amount to $1.1 million to $1.2 million under all three scenarios. NPV benefits of converting to an e-bus total $370,217, including avoided emissions ($57,387) and fossil fuel ($243,319) savings. NPV societal costs consist of the upfront capital costs plus energy ($29,466), ancillary ($1,694),

[63] See: PUC Rule 4.413.

and RECs ($2,334). Transmission and capacity costs were considered but not included in this analysis because GMT has agreed to charge the e-buses during off-peak periods as a condition of BED's rebate offer.

Figure 4-25: E-Bus Societal Cost Test Results



Conclusions and Course of Action

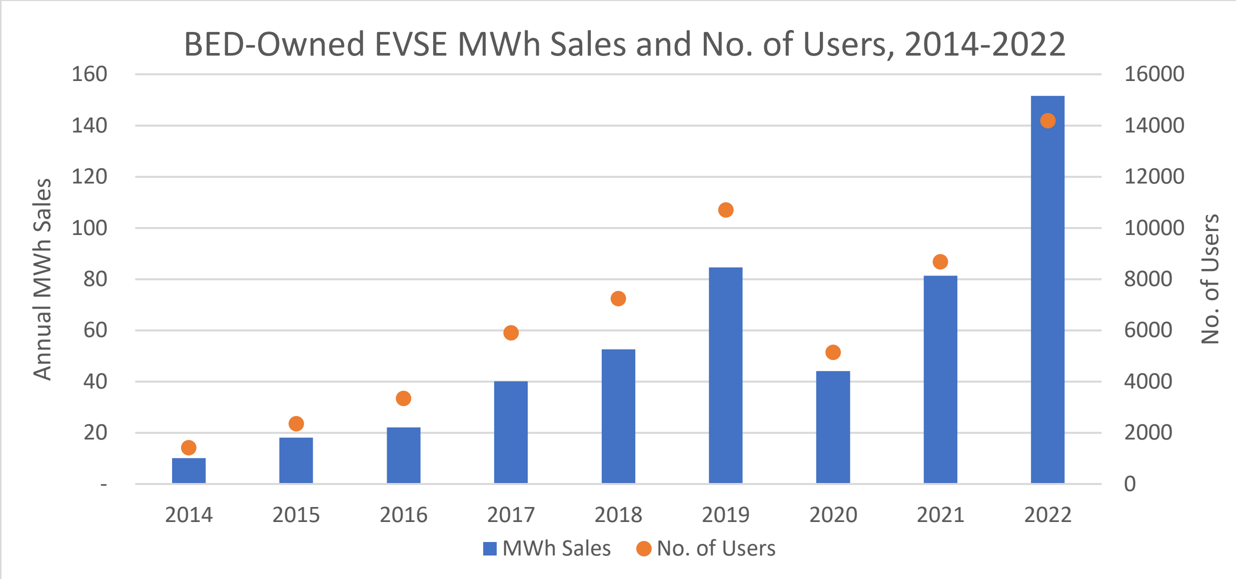
Although this analysis suggests e-buses are an expensive program to implement, BED believes continued support is appropriate to further the City's and Vermont's climate goals and requirements. BED also understands that over time e-bus costs are predicted to decline as manufacturers increase production and battery prices fall. Once e-buses attain cost parity with diesel-powered transit buses, BED will cease e-bus program operations.

Publicly Available Electric Vehicle Supply Equipment ("EVSE") and Workplace EVSE

A significant barrier to widespread EV adoption is "range anxiety." This occurs when car buyers believe they will be unable to find a publicly available EVSE to charge their electric vehicle. To reduce these misperceptions, BED has been strategically expanding its fleet of publicly available, affordably priced, highly visible, and conveniently located EVSEs throughout the City. Since 2015, the number of BED-owned EVSEs has expanded from 6 to 19 as of August 2023.

With the expansion of public EVSE stations (most of which are two-port, level 2, 7.2 kW systems), MWh sales have increased over time. Except for the pandemic years, growth in users has indicated a growing need for more publicly available charging facilities for a wide range of EV drivers: residents, commuters, and visitors.

Figure 4-26: BED-Owned EVSE MWh Sales and No. of Users, 2014-2022



As the number of EVs grows statewide, BED intends to continue expanding the number of publicly available EVSEs so that Burlingtonians, commuters, and visitors can conveniently charge their vehicles at affordable, tariffed rates. Some of the new EVSEs will be partially grant funded; others have been added to our capital budget and will be installed over the next several years. In addition to the 19 EVSEs already in service, BED plans to add up to 89 additional EVSEs by June 30, 2027.

Table 4-8: Planned Deployment of BED-Owned EVSE, FY23-FY27

FY	Level 2	DCFC / Level 3
2023	6	2
2024	9	3
2025	13	4
2026	17	5
2027	23	7
Total	**68**	**21**

Of the EVSEs expected to be installed over the next five to 10 years, BED is planning to install chargers in the following general locations:

- Downtown/Commercial core & parking garages
- Downtown/Residential on-street parking (including multifamily market-rate and low-income households)

- North End/Residential on-street parking (including multifamily market-rate and low-income households)
- South End/Residential on-street parking (including multifamily market-rate and low-income households)
- East/Residential on-street parking
- City Parks
- Schools
- Other City-owned buildings

In addition to expanding BED-owned EVSE, BED is actively promoting workplace and publicly available EVSEs located on private properties.

Since 2017, BED has provided incentives for 10 EVSE units located at workplaces throughout the City, including the University of Vermont ("UVM"), UVM Medical Center, Champlain Housing Trust, and Burlington Department of Public Works.[64] While uptake in this program has been slow due to the pandemic, BED is prepared to continue support workplace EVSE installations. In 2023, we increased the level 2 per-port Tier III incentive from $1,000 to $2,000 encourage participation. Organizations have responded positively. We also understand that UVM may be installing up to 24 new EVSEs in 2024 and 2025.

Although increasing the number of workplace units is important to BED, they are not the only chargers needed in the City. Because a large percentage of Burlingtonians reside in apartments where it is challenging to install EVSEs, BED offers Tier III and Act 151 incentives ranging from $300 to $1,500 per level 2 EVSE to multifamily ("MF") property owners. Since launching this program in 2020, BED has provided seven MF level 2 EVSEs incentives; some of these locations allow public charging by non-residents during business hours.

While progress in this market sector has been challenging for a host of reasons, BED is determined in its efforts to encourage property owners to install EVSEs and make them available to rental households. In the short term, BED is planning to install up to five utility pole–mounted, single-port, level 2 EVSE in areas of the City with a high proportion of MF units and/or lower-income households. These units will be partially grant-funded and need to be installed by the end of 2024. Longer-term plans include installing additional level 2 and level 3 units, as noted in Table 4-8 above.

Based on the current trajectory of workplace EVSE installations, BED anticipates associated MWh sales will approach 9,000 MWh annually.

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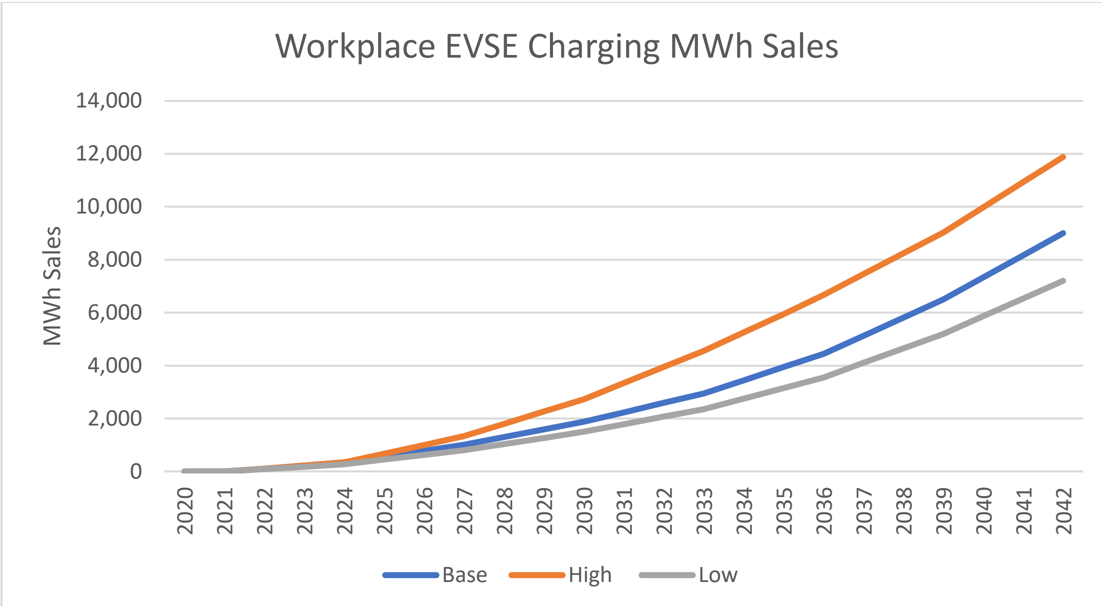
[64] EVSEs have been installed in other locations but the businesses hosting these EVSE locations have not participated in our Tier III program.

Figure 4-27: Workplace EVSE Charging Sales, 2020-2042



Major Assumptions and Inputs

To model the cost-effectiveness of level 2 and level 3 workplace EVSEs, BED relied on the following major inputs and assumptions.[65]

Table 4-9: Workplace Level 2 EVSE Cost-Effectiveness Assumptions

	Major Inputs - EVSE (Level 2 - workplace)	Cost/ Benefits	Source
Customer	Est. Installation Costs (Avg)	$ 3,200	TAG
	Fuel Savings	N/A	TAG
	Maint. Savings	$ (200)	BED
	Measure Life	10	TAG
BED	Increased kWH Sales (Avg)	4,260	TAG
	Net Lifetime Revenue (NPV)	$ 6,311	Calculated
	Tier III Costs	$ 4,600	Calculated
	Tier III Credits (avg)	61.74	BED Tier III Plan
	Net MWh e Costs (benefit)	$ (27.71)	Calculated
VT	GHG emissions reductions (tons)	4	TAG

[65] Cost-effectiveness tests were not undertaken for MF EVSE or BED-owned EVSEs. These types of EVSEs are assumed to be offered as either an amenity (in the case of MF EVSEs) and/or a public benefit ((in the case of BED-owned EVSEs). Accordingly, costs are socialized.

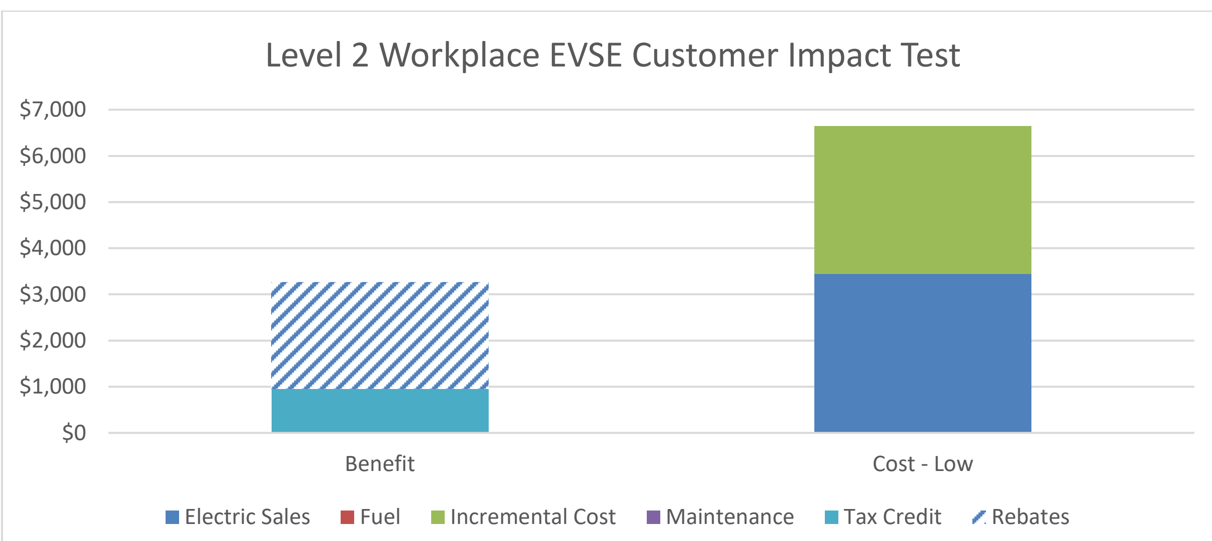
Table 4-10: Workplace Level 3 EVSE Cost-Effectiveness Assumptions

	Major Inputs - EVSE (Level 3)	Cost/ Benefits	Source
Customer	Est. Installation Costs (Avg)	$ 55,000	TAG
	Fuel Savings	N/A	TAG
	Measure Life	10	TAG
BED	Increased kWH Sales (Avg)	11,172	TAG
	Net Lifetime Revenue (NPV)	$ 16,550	Calculated
	Tier III Costs	$ 11,500	Calculated
	Tier III Credits (avg)	187.45	BED Tier III Plan
	Net MWh e Costs (benefit)	$ (26.94)	Calculated
VT	GHG emissions reductions (tons)	12.9	TAG

Customer Impact Test

Based on the above assumptions, the economics of installing a level 2 EVSE at a workplace are poor to the business owner, even with BED's direct incentives and federal tax credits. As shown in Figure 4-28, net costs exceed benefits by $3,300. Some costs to the business owner could be recoverable if a fee were charged to users. However, BED understands that businesses typically provide EVSE charging as a loss-leader for now or for free to their workers and/or guests as part of an overarching climate initiative or perk.

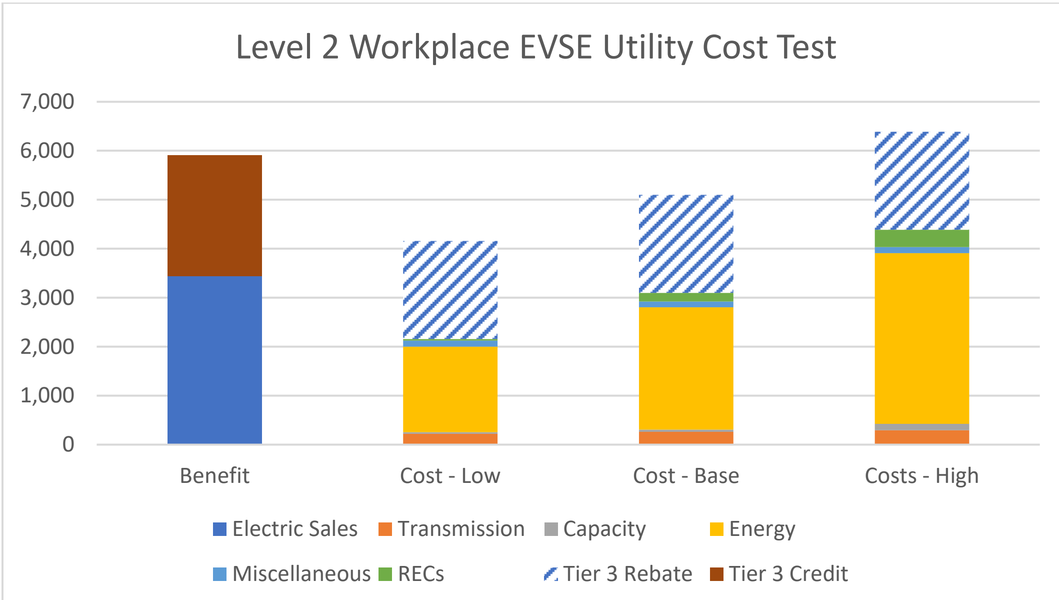
Figure 4-28: Level 2 Workplace EVSE Customer Impact Test Results



Utility Cost Test

Under the UTC, BED's net benefits equal $800 per workplace level 2 EVSE, under base case assumptions. Benefits flow from increased MWh sales ($3441) and avoidance of paying an ACP ($2469). Utility costs consist of rebates ($2000), transmission ($262), capacity ($47), energy ($2493), RECs ($177), and miscellaneous ($122).

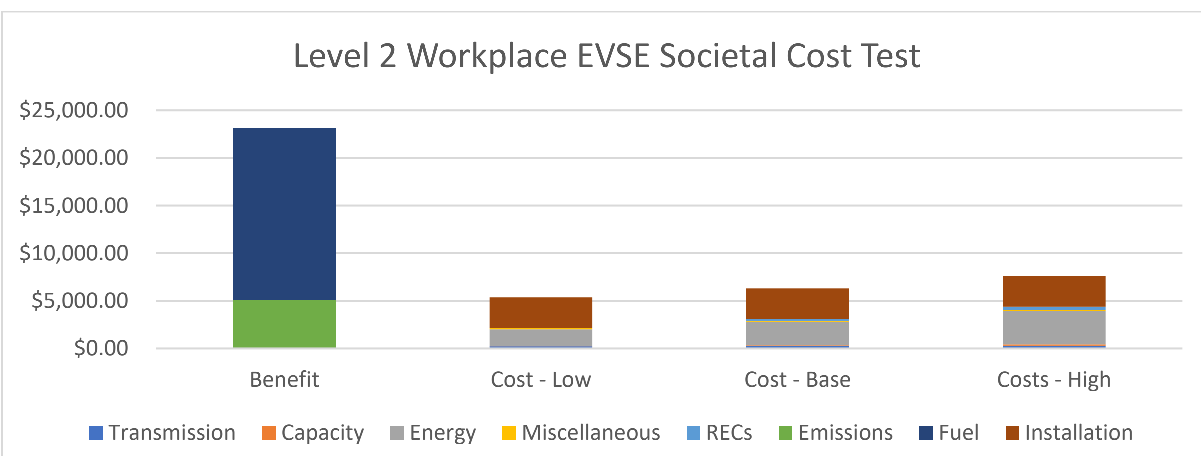
Figure 4-29: Level 2 Workplace EVSE Utility Cost Test Results



Societal Cost Test

On a net basis, societal benefits amount to over $16,800 under base case assumptions due to avoided fuel costs ($18,111) and avoided GHG emissions costs ($5,052). Costs include transmission ($261), capacity ($48), energy ($2492), RECs ($177), miscellaneous ($122), and installation ($3200).

Figure 4-30: Level 2 Workplace EVSE Societal Cost Test Results



Conclusions and Course of Action

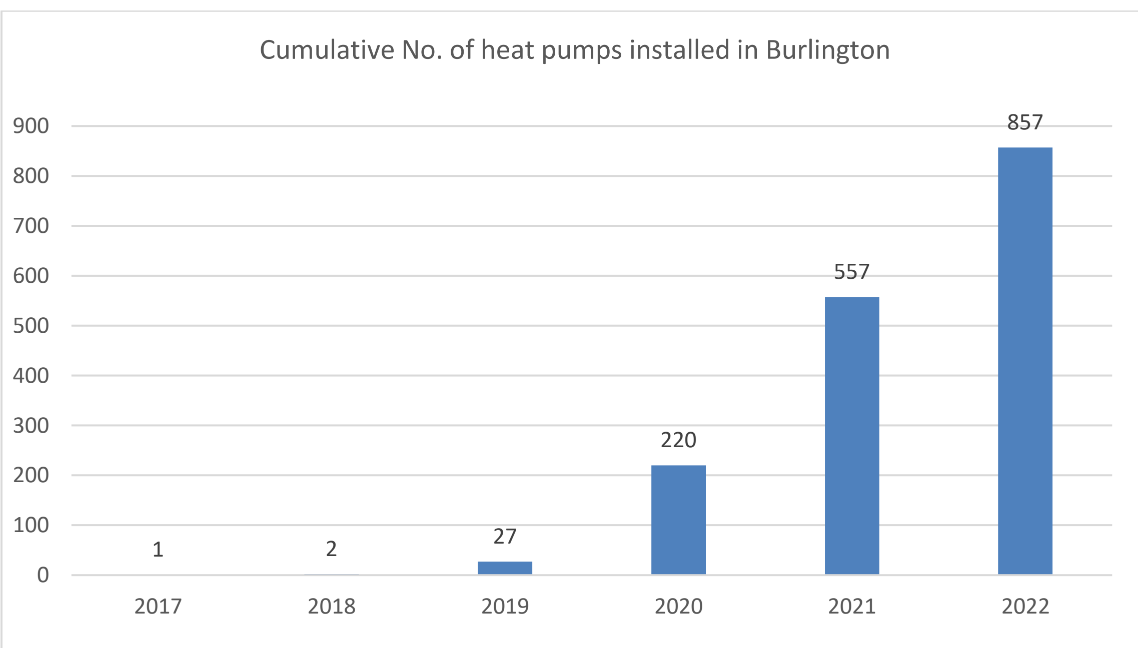
Because of the positive net societal benefits, BED intends to continue supporting this program. Increasing the number of EVSE installations is an important facet of the City's (and Vermont's) overall objective to increase the number of EVs registered in the region.

Advanced Heat Pumps

Transitioning toward renewably sourced building space heat is a priority as it is the leading source of GHG emissions in the City.[66] BED began offering financial incentives for heat pumps in 2017, the first year of the RES. Initially, heat pump adoption was very low, mostly because advanced heat pumps were unfamiliar to most customers and Vermont's utilities were just beginning to offer financial incentives for them.

Although earlier versions of heat pump technology are omnipresent in buildings worldwide (i.e., ductless heat pumps used mostly for cooling with limited space heating capabilities), relying on heat pumps for heating has been uncommon in Vermont until recently due to our cold winters. Starting in 2019, as Vermonters have learned about how modern cold climate heat pumps work in their homes and buildings, and as heat pump efficiencies have improved, the number of installations statewide has increased dramatically. More Vermont households are beginning to rely on their heat pumps for a greater proportion of their space heating needs, as well as for cooling and dehumidification. In the City of Burlington, heat pump adoption has increased by nearly four-fold since 2020, as shown in Figure 4-31.

Figure 4-31: Cumulative Heat Pump Installations in Burlington, 2017-2022



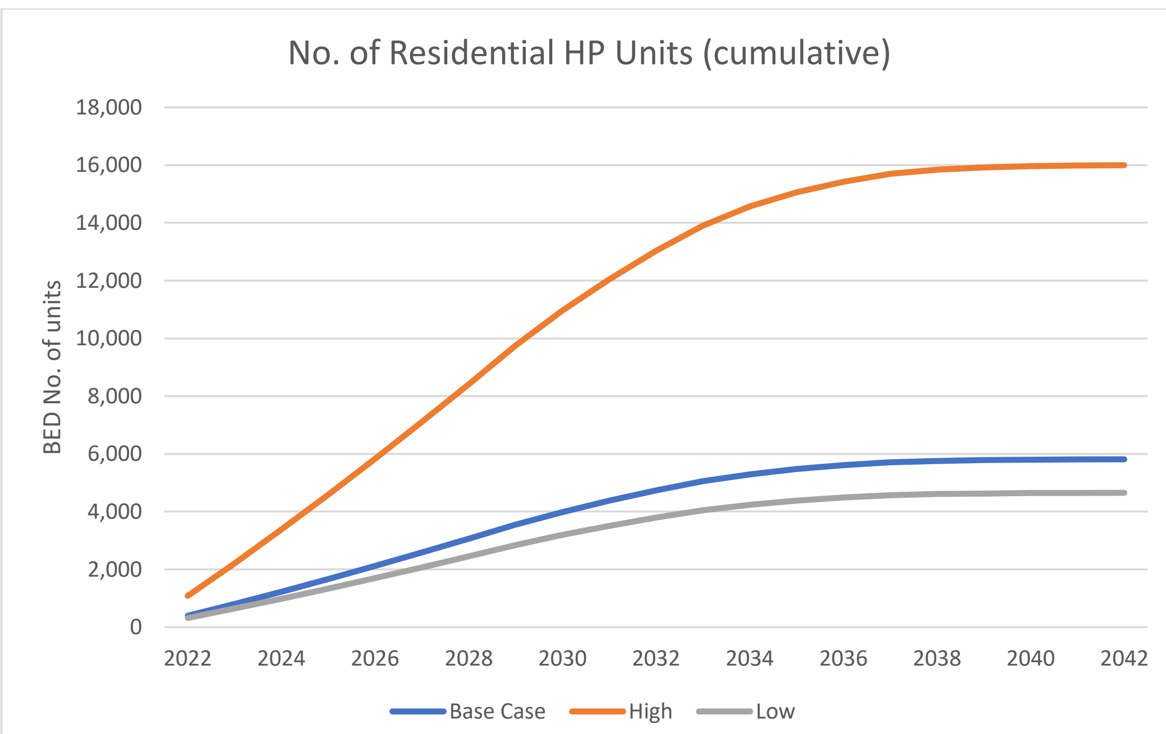
[66] See; BED's Net Zero Energy Pathway report, at pg. 23.

The popularity of heat pumps can be attributed to several reasons, including, but not limited to:

- Increased efficiency of new advanced heat pumps relative to previous heat pump technologies.
- For new construction and major renovations projects, the cost to install an advanced heat pump is competitive with the installation cost of natural gas boilers, furnaces, and standard air conditioning equipment.
- For customers seeking to reduce their carbon footprint, heat pumps are a logical heating and cooling solution.
- Strong financial incentives from BED, as well as federal income tax credits for some households.
- Advanced heat pumps are fast becoming an integral line of business for many building/heating contractors in Vermont.

Like other distribution utilities, BED believes that the popularity of advanced heat pumps (and the rate of installation growth) will continue unabated for several more years. For planning purposes, BED anticipates that heat pump adoption will continue to increase under the base case scenario by 30% (on average) annually over the next 10 years before leveling off. That means the number of units installed will likely increase from 857 units in 2022 to approximately 6000 units in 2042; and potentially 16,000 under a high case scenario.

Figure 4-32: Projected No. of Residential Heat Pump Installations (cumulative), 2022-2042

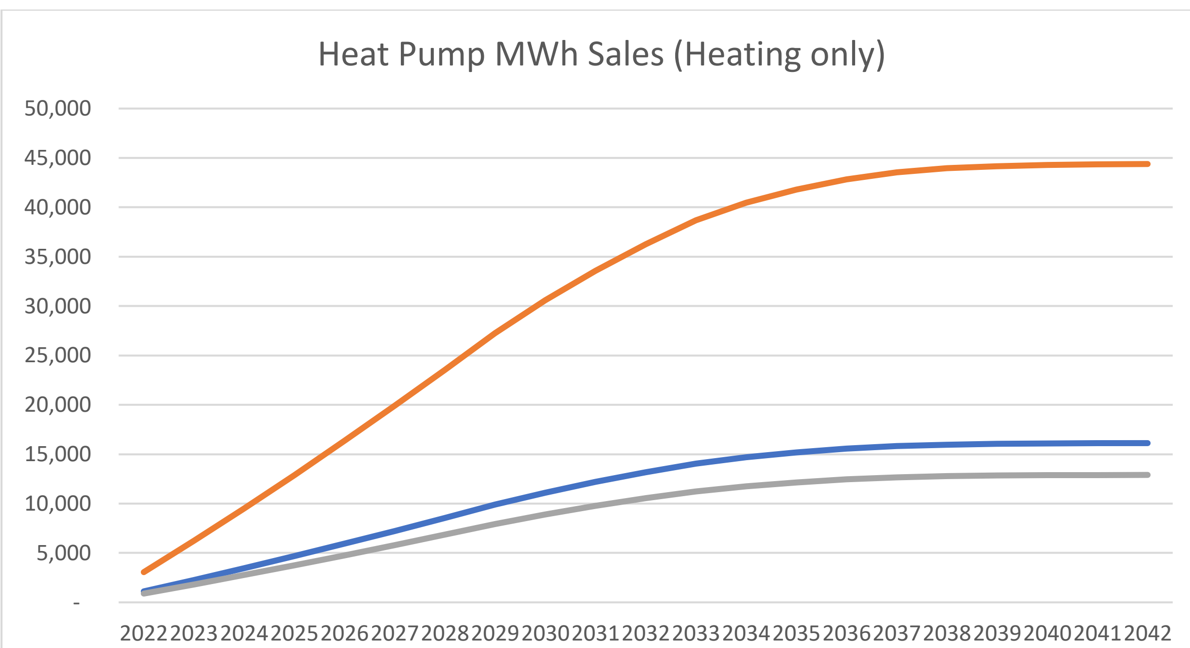


Assuming our forecasts prove to be roughly accurate, approximately 30% of households (measured as a percentage of residential electric accounts) will have at least one heat pump installed under the base case scenario. Under the high case, roughly 82% of households will have a heat pump.

It is important to note that Figure 4-32 reflects residential household adoption only. While businesses may also install heat pumps, especially smaller businesses, we believe residential demand for heat pump solutions for heating will be a driving force behind increased electricity consumption. Future commercial-grade demand for heat pumps (and thus electric consumption) will likely be relatively lower than residential demand, and the rate of growth comparatively slower. Commercial heat pump solutions also are more likely to be installed on a custom project basis as the heating needs and operations of commercial customers are much more complicated than the needs of residential customers. BED will, however, closely monitor the commercial heating sector to determine whether electrically sourced heating demands increase substantially more than our current outlook. As appropriate, BED will incorporate our observations in this important sector in our 2026 IRP.

As more heat pumps are installed in the City, electricity sales are expected to increase during the winter and shoulder seasons. BED believes such increases are manageable, even under the high case scenario.

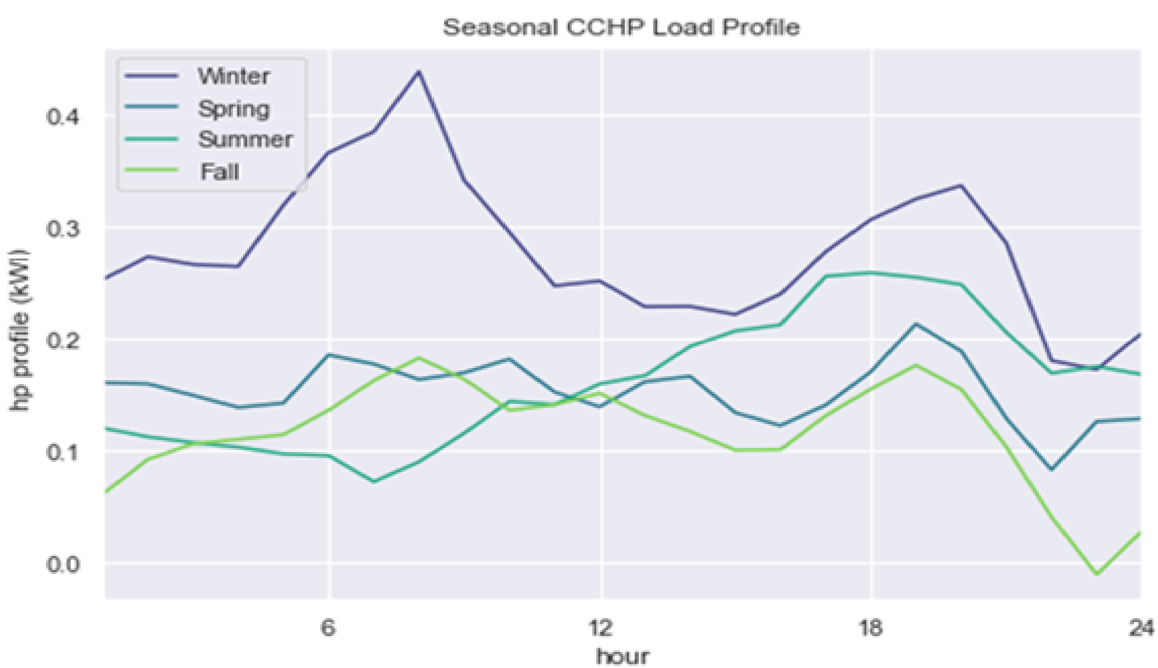
Figure 4-33: Projected Heat Pump MWh Sales (heating only), 2022-2042



BED anticipates that new, incremental, heating-related MWh loads under the high case scenario will increase relatively sharply in the earlier years of the planning period but then level off. As time goes on, barriers to heat pump installations will become increasingly harder to overcome (such as home electric panel upgrades) and the opportunities to make the transition to renewable electric heating less frequent.

Heat pump adoption will also impact coincident winter and summer peak demand. According to a 2018 Cadmus evaluation, a heat pump adds 0.35 kW to the winter coincident peak and 0.15 kW to summer coincident peak. Monthly transmission impacts, however, remain highly variable since the demand for heat pump power is driven by outside temperatures. Nevertheless, Figure 4-34 below is illustrative of a load profile of a typical Burlington household after the installation of a 1-ton heat pump. This particular installation draws about 0.1 kW more of demand (about 0.425 kW) during the winter than Cadmus estimated in their heat pump evaluation.

Figure 4-34: Typical Cold-Climate Heat Pump Load Profile



To better manage heat pump demand, BED is in the process of evaluating the merits of a pilot program designed to modulate the use of heat pumps during monthly peak demand periods. Under this pilot program, customers would install communications and controls technologies that would allow BED to turn down the heating needs of customers for short periods of time, thus reducing the need for winter peak power. During the summer months, BED will signal customers to either pre-cool their space in advance of a peak demand event and/or modulate the customer's cooling intensity (i.e., turn up temperatures) during events. In both scenarios, customers would have the option to opt out of BED's call for demand responses. In addition, BED is currently working on developing a time- and weather-sensitive heat pump end-use rate credit program—similar to our existing EV rate credit tariff. We envision that such a rate credit program—if fully developed and approved—would provide customers with additional incentives to maximize the efficiency and economics of their heat pumps.

To further encourage new customers to install heat pumps, BED plans to continue offering strong financial incentives to customers and installers for several more years. We believe the incentive structures, as outlined below, have been instrumental to the success of this program.

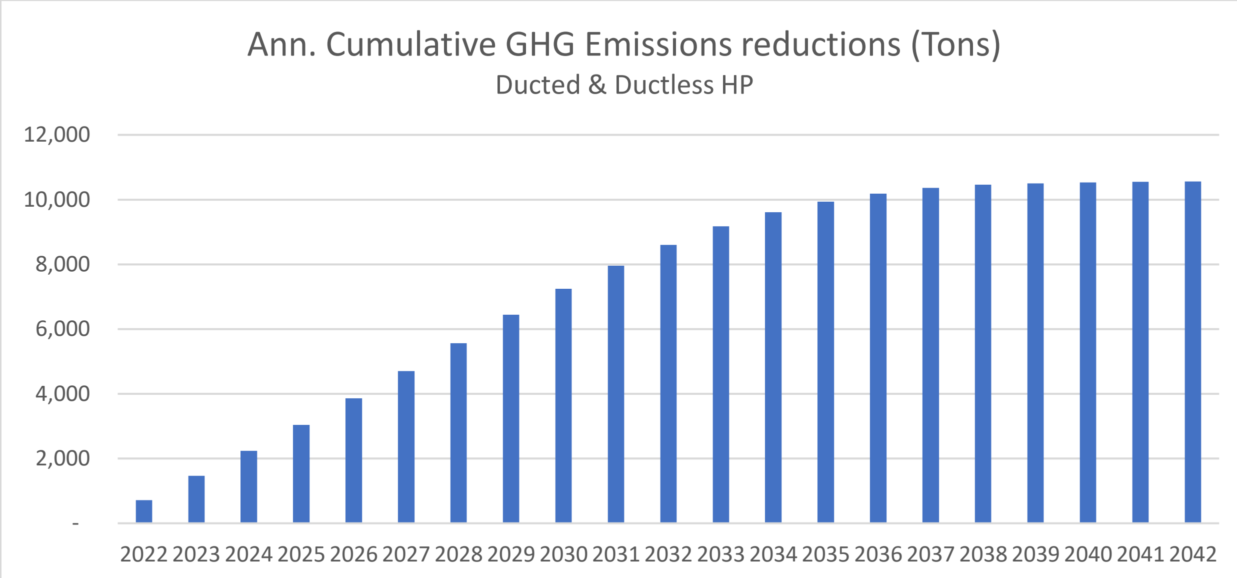
Table 4-11: BED Heat Pump Incentives

Type & Size	Tier III Mkt Rate	Enhanced (LI)	EEU (mid-stream)	Act 151	Up to Total
Ductless, < 2 tons	$ 1,100	$ 400	$ 350	$ 1,000	$ 2,850
Ductless, 2+ tons	$ 2,000	$ 400	$ 450	$ 500	$ 3,350
Ductless (2nd unit)	$ 250	$ 400	$ 350	$ 250	$ 1,250
Ducted Hi Perf < 2 tons	$ 2,000	$ 400	$ -	$ 250	$ 2,650
Ducted Hi Perf 2 - 4 tons	$ 4,000	$ 400	$ -	$ 250	$ 4,650
Ducted Hi Perf 4+ tons	$ 6,000	$ 400	$ -	$ 250	$ 6,650
Ducted Std < 2 tons	$ 1,000	$ 400	$ -	$ 250	$ 1,650
Ducted Std 2 - 4 tons	$ 2,000	$ 400	$ -	$ 250	$ 2,650
Ducted Std 4+ tons	$ 3,000	$ 400		$ 250	$ 3,650
AWHP (per ton - DU, per Unit - LI & Act 151)	$ 2,000	$ 400	$ -	$ 600	$ 3,000

For centrally ducted heat pumps, BED currently offers a two-tiered incentive structure. This format encourages the installation of more efficient and better-performing systems that can sustain high heating output as measured in BTUs/hour over a much wider range of outside temperatures. Better systems also reduce GHG emissions more over time relative to less robust heat pump systems without sacrificing building comfort.

If the program successfully encourages residential customers to transition to advanced heat pumps, BED anticipates GHG emissions could be lowered by as much as 10,000 metric tons annually by 2035, and each year thereafter so long heat pumps become and remain a primary residential heating solution, as shown in Figure 4-35.

Figure 4-35: Projected Cumulative GHG Emissions Reductions from Heat Pump Deployment, 2020-2042



Major Assumptions and Inputs

To model the cost-effectiveness of advanced heat pumps, BED relied on the following major inputs and assumptions.

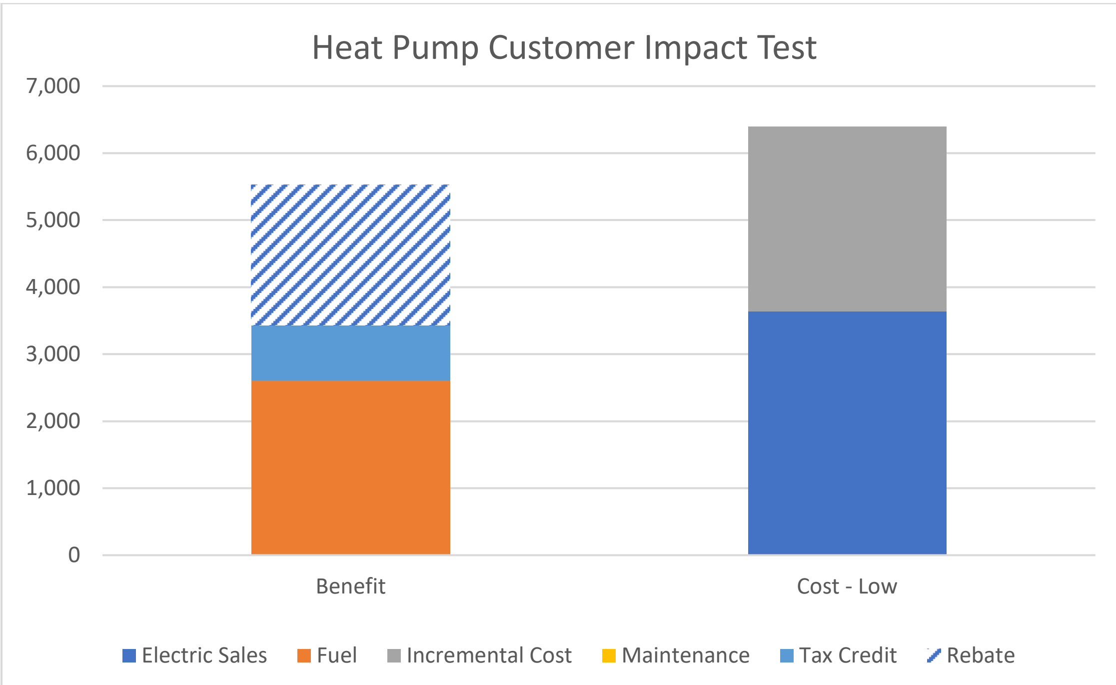
Table 4-12: Heat Pump Cost-Effectiveness Assumptions

	Major Inputs - Adv. Heat pumps (1 ton)	Costs/ Benefits	Source
Customer	Est. Installation Costs (Avg)	$2,761	TAG
	Fuel Savings	0	TAG
	Measure Life	15	TAG
BED	Increased kWH Sales (Avg)	1,578	TAG
	Net Lifetime Revenue (NPV)	$ 3,383	Calculated
	Tier III Costs	$ 1,265	Calculated
	Tier III Credits (avg)	20.25	BED Tier III Plan
	Net MWh e Costs	$ (106)	Calculated
VT	GHG emissions reductions (tons)	2.45	TAG

Customer Impact Test

Based on the TAG assumptions used for calculating Tier III credits, BED believes customers' heating costs may increase should they install a 1-ton advanced heat pump. This analysis, however, does not account for cooling benefits (relative to room air conditioners) and dehumidification. The reasons for increased heating costs are primarily due to the low cost of natural gas. On balance, a customer's net costs would amount to $865 since net costs ($6,398) exceed savings ($5,532). Net costs include increased electric costs ($3,637) and incremental capital costs ($2,761). NPV benefits include natural gas savings ($2,604), federal tax credits ($828), and BED's rebate ($2,100).

Figure 4-36: Heat Pump Customer Impact Test Results

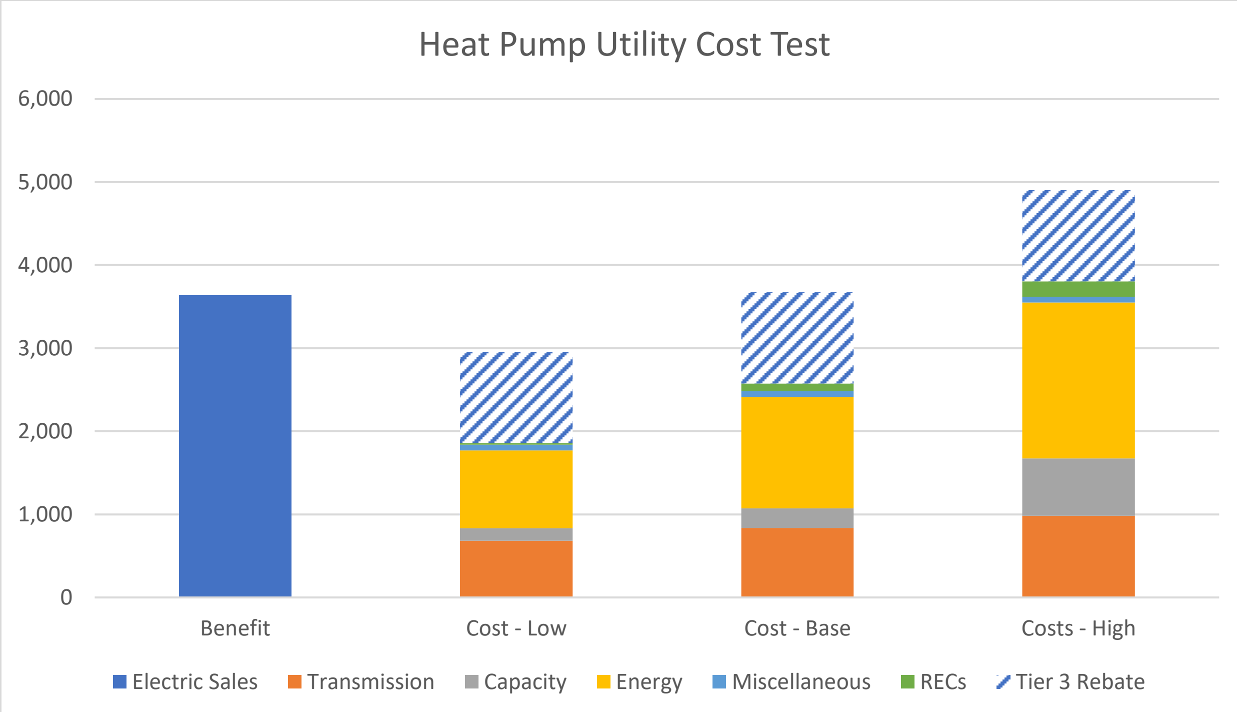


Despite higher heating costs, many customers are still choosing to retrofit their home's heating systems to lower their carbon emissions and increase indoor comfort during the summer. Also, in new construction and major renovation projects, many customers and contractors elect to install advanced heat pumps due to lower upfront costs, as well as to comply with local building ordinances, if applicable.

Utility Cost Test

Under base case assumptions, BED's NPV program benefits equal NPV costs. Benefits consist solely of incremental MWh sales ($3,637) over 15 years. NPV costs include transmission ($836), capacity ($238), energy ($1,339), ancillary ($71), RECs ($91), and Tier III rebates ($1,100).

Figure 4-37: Heat Pump Utility Cost Test Results



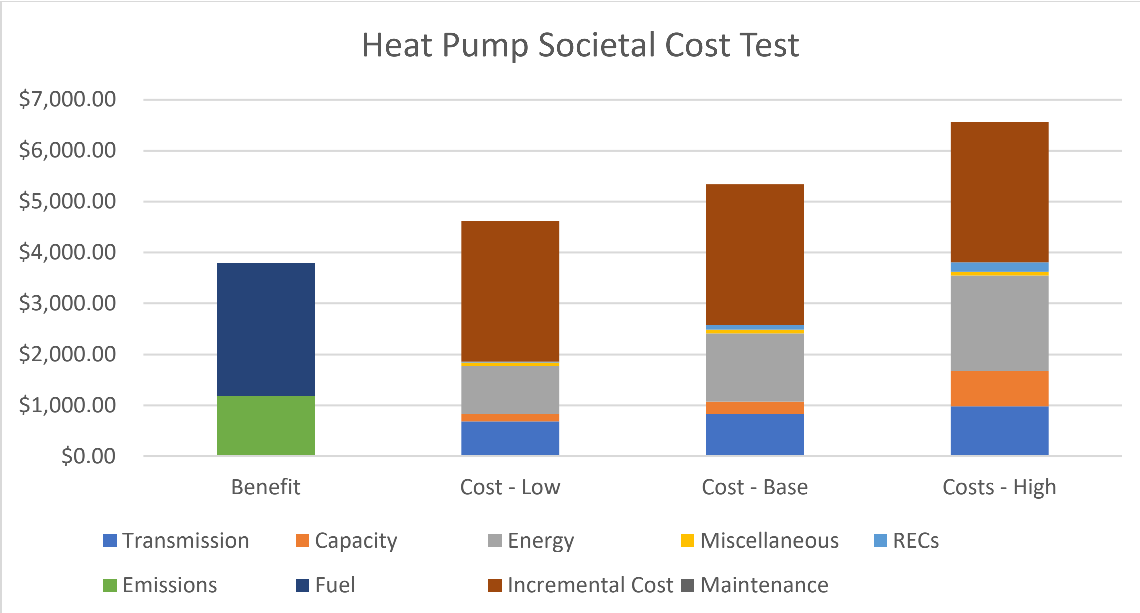
Even though NPV utility benefits equal NPV utility costs under base case assumptions, BED remains committed to providing strong customer incentives for the short to intermediate term. Continuing this level of support is necessary in order to further encourage BED's customers to transition away from natural gas and for Vermont to achieve its climate energy requirements.

Over time, BED expects it will gradually lower incentives as federal incentives (i.e. Inflation Reduction Act) become available, unit installation prices fall and advanced heat pumps become more available. As incentives decrease, BED's utility benefits will increase. Utility benefits may also improve over time as demand response capabilities improve, allowing BED to avoid high-cost energy and transmission cost periods.

Societal Cost Test

On a societal basis, NPV costs exceed benefits by $1,500 over 15 years. NPV benefits consist of avoided emissions costs ($1,191) and fuel savings ($2,600). NPV costs include incremental capital costs ($2,761), transmission ($835), capacity ($238), energy ($1,339), ancillary ($71), and RECs ($90).

Figure 4-38: Heat Pump Societal Cost Test Results



Similar to our customer impact analyses, societal costs exceed benefits due to low natural gas prices. In addition, rebates and federal tax credits are not included in the SCT as these payments represent monetary transfers from one group of customers to another.

Conclusions and Course of Action

BED believes that while societal costs exceed benefits today in natural gas service areas, net benefits will likely increase as Vermont's ability to comply with the Global Warming Solutions Act are challenged over time, resulting in higher avoided carbon benefits. Accordingly, BED plans to continue its popular advanced heat pump program for the near to intermediate term.

Beneficial Electrification Conclusions

Continuing support of our beneficial electrification programs is a significant priority for BED. Through these programs, BED can actively encourage customers to transition away from fossil fuel consumption to achieve the City's NZE goal and also comply with Vermont's various climate policies. While these programs increase electric loads, we are mindful of the potential impacts more heat pumps and EVs may have on the electric grid. To minimize these types of impacts, we introduced the EV rate credit program several years ago. Since its introduction, over 1200 EV owners now charge their vehicles between 10 pm and 11:59 am on a daily basis. As noted above, off-peak charging provides for several benefits to BED and its customers, as well as the EV rate credit participant. Over time, we will continue our efforts to expand the number of participants in this program.

BED is also conducting pilot programs to moderate heat pump consumption. If these pilot programs are successful, BED will be able to implement a series of demand response programs during weather events and reduce peak demands, saving customers money over time.

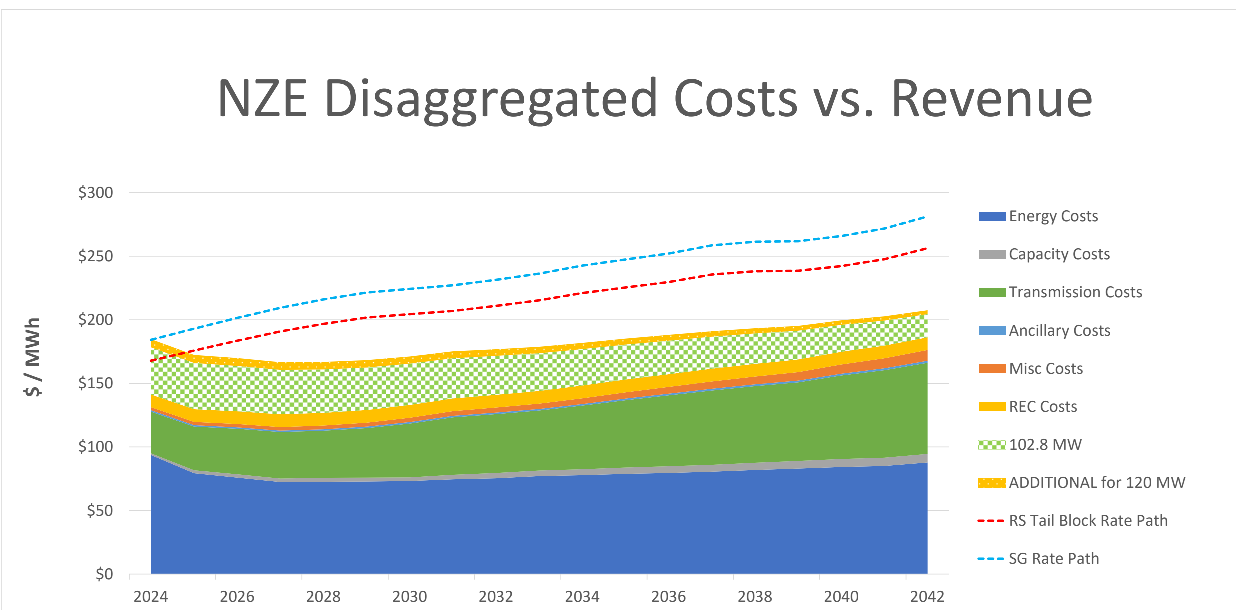
In addition to reducing carbon emissions in the building heating and transportation sectors, BED's beneficial electrification programs can also be viewed as a least-cost option to comply with Vermont's clean energy policies. All of the programs cost BED less than the ACP, which is $71.83 for 2023. Accordingly, BED will seek to sustain its financial and technical support of these programs over the next several years.

5. Financial Assessment and Potential Rate Pressure

Pressure to increase rates exists for all utilities due to factors including inflation (both for materials and labor), fuel price changes, and the impacts of system growth, particularly growth in peak demand. Managing the risks that lead to rate pressures is one of BED's primary goals, and from 2009 to 2021, BED successfully did so without having to raise rates. Since then, BED has found it necessary to request three rate increases despite our risk-management efforts, due to factors including impacts of the COVID-19 pandemic, higher inflation and cost of living adjustment increases, increased regional network service ("RNS") tariffs, increased debt service expense, and relatively flat retail energy sales.

Although unpredictable to a precise degree, continued macroeconomic and power supply market changes over time are inevitable. Thus, it is imperative to understand and evaluate pertinent operating and economic factors that could increase rates and how BED's decisions could increase or decrease rate pressure. Accordingly, BED uses its IRP financial model to establish a "baseline" profile of risks and assumptions that tend to exert upward or downward pressure on rates. The model can then be used to evaluate short- and intermediate-term actions, such as strategic electrification (see the NZE chapter for additional detail), that could affect rates. For example, Figure 5-1 below, which also appears in the Net Zero Energy chapter, illustrates the estimated impact of the NZE/beneficial electrification pathway on rate pressures over time.

Figure 5-1: NZE Disaggregated Costs vs. Revenue



20-Year IRP Financial Model

Methodology

The financial model developed for this IRP projects BED's "base case" costs and other revenue from Fiscal Year ("FY") 2024 to FY 2043. The first five fiscal years (2024-2028) of this model derive from a more detailed five-year financial forecast prepared annually by BED.[67]

The IRP model is used to generate a profile of plausible risks that create "rate pressure" over time. We define rate pressure as the Cost of Service divided by Customer Sales. The use of a rate pressure profile has advantages over a simple 20-year net present value ("NPV") cost-of-service as it provides information on the timing of impacts and the beneficial impacts, if any, on rates from increases in load. For example, while overall costs may increase to serve greater loads due to electrification, average costs per kWh may be reduced because incremental costs are recoverable over many more kWh sales.

BED's model allows for the development of 5- and 20-year net discounted values of the cost to serve BED's customers. The cost to serve load, in turn, is influenced by several key variables such as inflation, wholesale energy costs, RNS charges, and REC prices. These key variables vary both in their past volatility and in the magnitude of their pressure on the direction of rates. To better understand which risks have a greater overall impact on the cost to serve load, BED's IRP model can be used to create "tornado charts" that illustrate the range of assumed costs affecting rates. The wider the range, the greater the risk.

BED hedges certain key variables such as energy and REC prices through purchases and sales in the initial five-year period of the IRP. Hedging lowers BED's risk profile. Similarly, short-term capacity costs are "hedged" as the current forward capacity market ("FCM") structure locks in capacity prices for next three years. After this three-year period, capacity cost risk increases. Because some high-risk inputs can be hedged or are known in the short and intermediate term, a 20-year tornado analysis of these inputs may appear to be of lower concern when the five-year impact on utility costs is considered.

Finally, we note that: (1) the IRP financial model was prepared at a high level and is not intended to support a current or future rate filing, which would require known and measurable support and prior local government approvals and (2) the model does not attempt to assess the timing of rate increases or decreases, but only the direction and magnitude of such rate changes due to key inputs/assumptions.

[67] For this analysis, the last six months of FY2043 load were calculated as the corresponding FY2042 load multiplied by the percentage growth from FY2041 to FY2042.

Assumptions

A 20-year forecast is dependent on many variables. These are discussed below, as well as the impact of potential expected changes in those variables on BED's bottom line.

Net Power Costs

BED uses a power cost model based on its one- to five-year budgeting model with assumptions extended for the remaining 15 years of the 20-year period. Many assumptions, such as ISO-NE ancillary costs, are forecast with simple escalation factors. Some variables, however, receive a multi-scenario treatment due to their relative impact on the overall net power cost budget, as described in more detail below.

Meaning of "Long" and "Short" in this IRP

Under the ISO-NE energy market structure, a utility like BED is responsible for buying the energy its customers require. BED then offsets those costs by selling the energy from its resources to the wholesale energy market. The same general process applies to the ISO-NE FCM as well. If BED has excess energy or capacity resources (i.e., "long" energy or capacity) during periods of high wholesale energy prices and demand, the increased load cost tends to be more than offset by increases in revenue from generation. Conversely, in situations when BED is "short" on either energy or capacity and needs to purchase additional supply at higher prices to serve loads in the City, generation revenue is generally insufficient to offset the higher costs. If BED can maintain a balance, in most hours, between generation and load settlement, BED's cost to serve load should not be materially affected by ISO-NE's wholesale market prices.

As energy and capacity prices change over time, so too does BED's net cost to serve load. Table 5-1, below, provides a summary of the potential impacts of wholesale prices on BED from the perspective as both a generator and load-serving entity. Being long—that is, a net supplier of a resource—means that high prices generally benefit you, with the opposite being true when you are a net purchaser (i.e., high prices harm a net purchaser). This discussion focuses on energy and capacity, but many of ISO-NE's markets (e.g., regulation/AGC, Forward Reserves, etc.) possess a similar dynamic and if BED were "long" for any market or product it would have similar implications.

A recent dramatic example of this concept occurred over the winter of 2022 and 2023. The forward energy prices for the winter were exceedingly high: average December 2022-March 2023 forward prices were $189/MWh in June of 2022. During the winter, however, the actual average energy price received by BED for the sale of its excess energy was $64/MWh. Thus, BED realized dramatically lower revenue for the sale of excess energy in FY 2023 than was assumed in its 2022 rate filing. While some divergence between forward prices and actual wholesale market "spot prices" for energy occurs for every period, the magnitude of the divergence for winter 2022-2023 was unprecedented. Although these price differences between forward and actual prices is not a new risk, the magnitude of this difference was. The greatest divergence prior to winter 2022-2023 occurred in the winter of 2013-2014, when the actual price was $62/MWh higher than the forward price projected in May 2013. The second greatest divergence was in the winter of 2014-2015, when the departure occurred in the opposite direction, with actual prices $53/MWh lower than the forward price projected in May 2014 as happened in the winter of 22-23). By comparison, the price divergence for winter 2022-2023 was $120/MWh between May 2022 forwards and actual, and $160/MWh between November 2022 forwards and actual—two to three times the magnitude of the two prior highest divergences. Also, BED's exposure to this risk has varied over time. During the winter of 2013-2014 BED had 18 GWh of excess energy (so the variance favored BED), during the winter of 2014-2015 BED was 2 GWh short (so the variance had little effect), and during the winter of 2022-2023 BED had 34 GWh of excess energy.

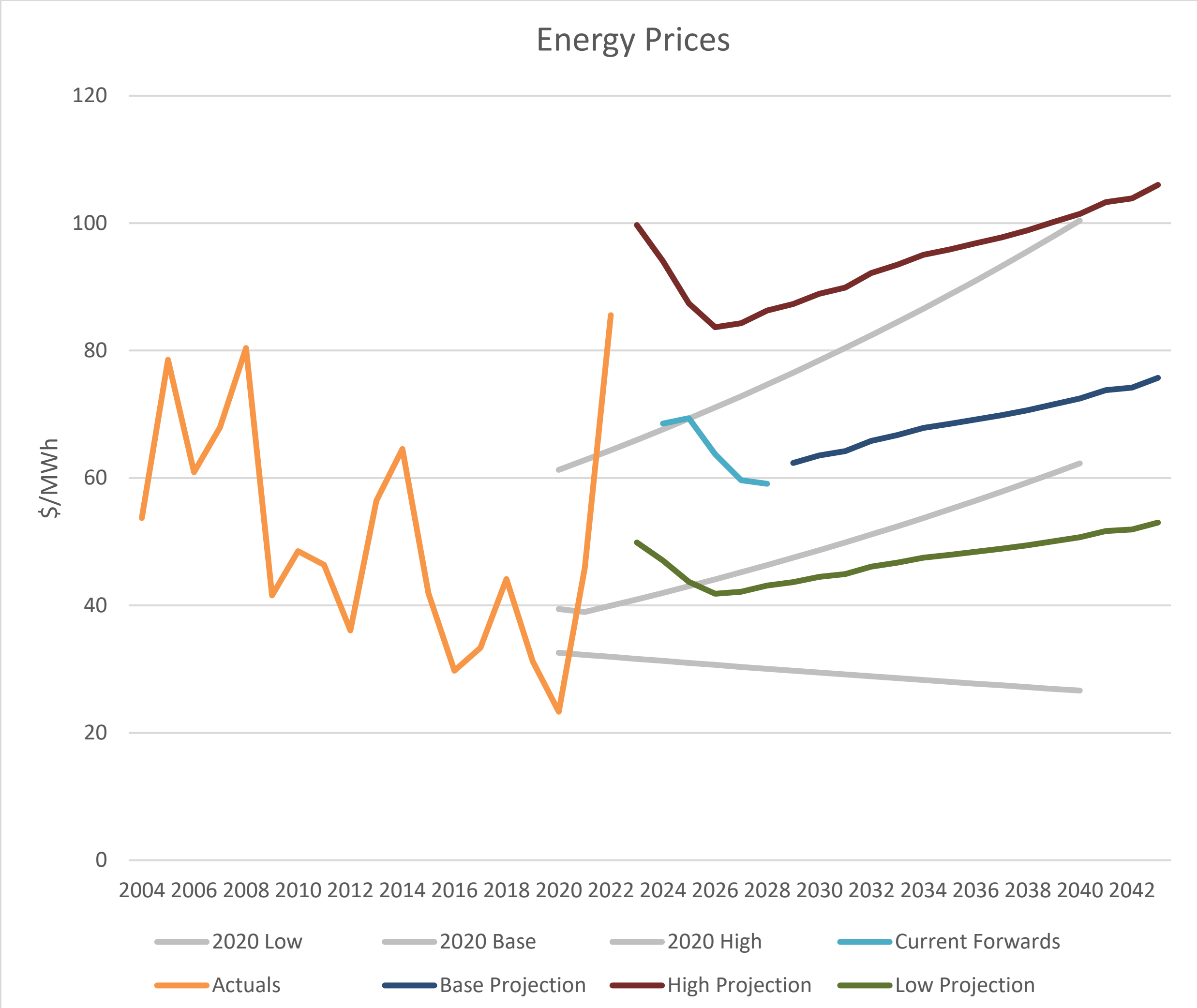
Table 5-1: Wholesale Energy and Capacity Price Effects on BED's Cost of Service

	ISO NE Wholesale Prices from BED's Dual Perspectives	
	High prices	**Low prices**
Long	Benefit (higher net resource revenues)	Cost (lower net resource revenue)
Short	Cost (higher net load charges)	Benefit (lower net load charges)

Wholesale Energy prices

As in the past, BED expects energy costs to continue to fluctuate. As shown in Figure 5-2 below, the model assumes that prices will increase over the long term, with the starting point being somewhat higher before falling, given recent increases in and the shape of wholesale energy prices and forwards. We have modeled low, base, and high energy price cases to capture the range of expected variability.

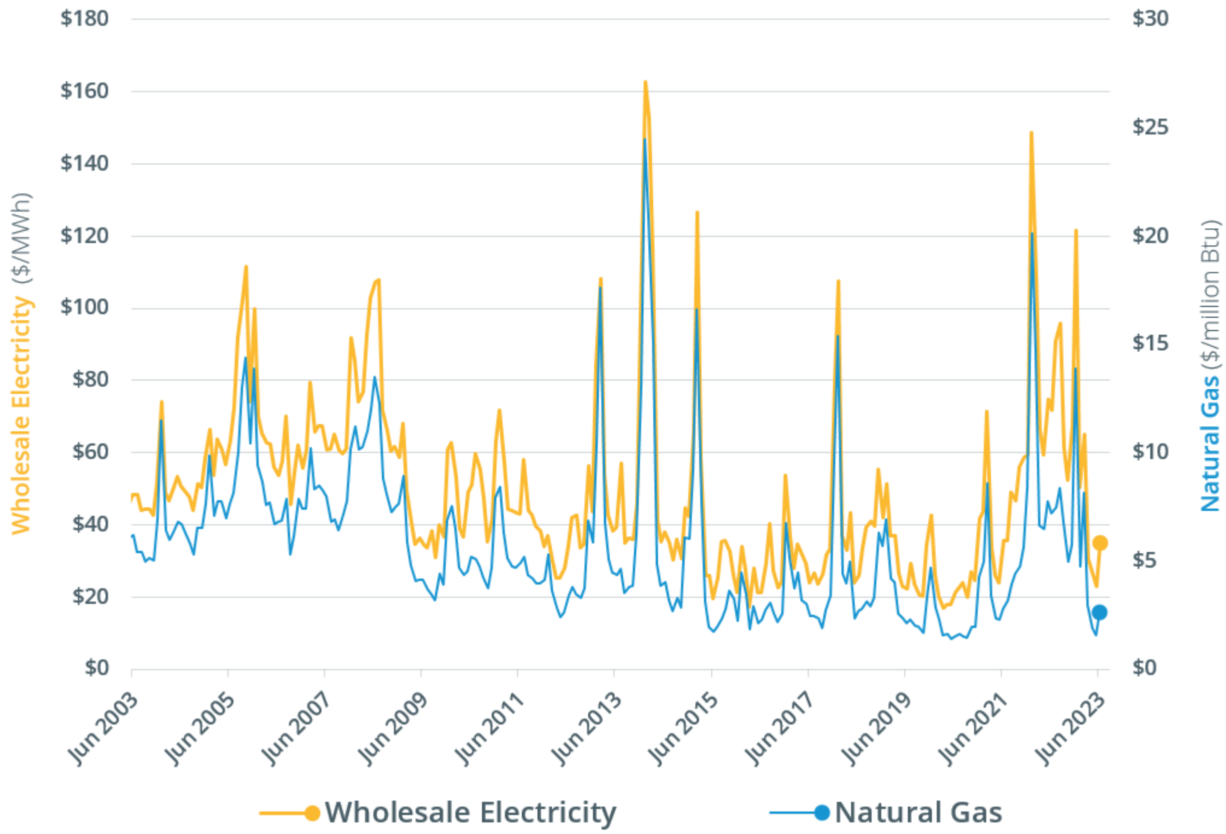
Figure 5-2: Wholesale Energy Price Forecast



Wholesale electric energy prices are influenced by myriad factors. The single greatest influence on future electric prices in New England is natural gas prices. Between 2000 and 2022, the average share of natural gas–fueled electric generation in New England has increased from 15% to 46%.[68] Generally, natural gas electric generators are the marginal unit of production and thus set wholesale electric prices in New England in most hours. This is reflected in the strong correlation between natural gas prices and wholesale electric prices, as shown in Figure 5-3.

Figure 5-3: New England Wholesale Electric and Natural Gas Prices[69]

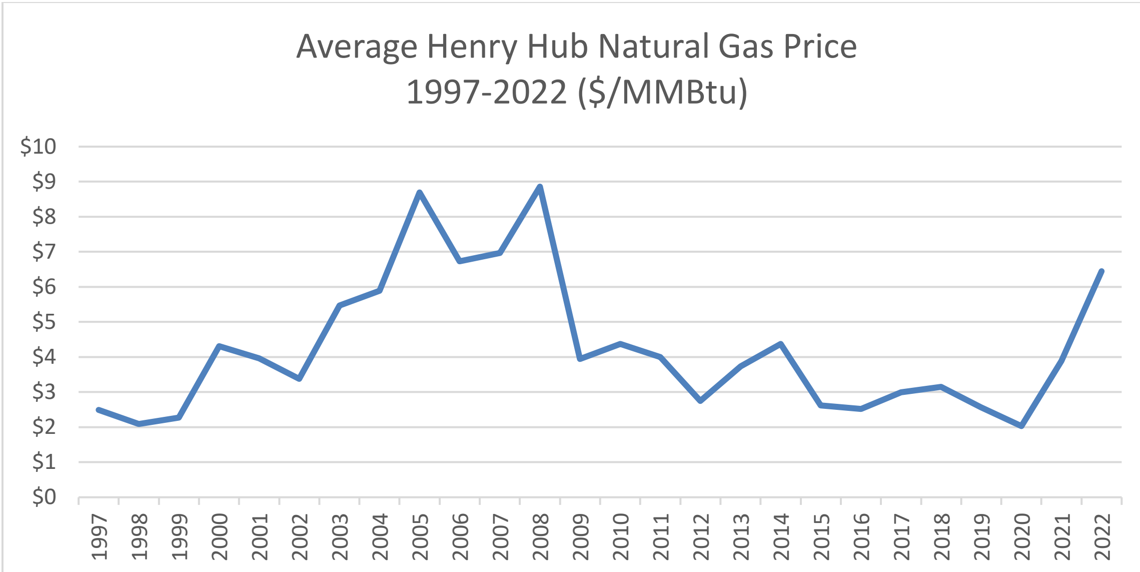
[68] https://www.iso-ne.com/static-assets/documents/2021/03/new_england_power_grid_regional_profile.pdf, accessed August 2023.
[69] https://isonewswire.com/2023/07/25/monthly-wholesale-electricity-prices-and-demand-in-new-england-june-2023/, accessed August 2023



Over this same period, the price of wholesale spot natural gas at the Henry Hub has gyrated from a low of less than $2/mmBTU to a high of $9/mmBTU in 2008, as shown in Figure 5-4. More recently, in 2022, spot natural gas prices at the Henry Hub gateway averaged more than $6/mmBTU.[70] Longer term, natural gas prices are expected to increase moderately; therefore, wholesale electric prices are also expected to rise by roughly 2 to 2.5%[71] annually over the IRP time period.

[70] See; https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm, accessed September 2023.
[71] This is close to the assumed inflation rate for this period.

Figure 5-4: Historical Henry Hub Prices



An additional concern related to energy prices in New England is the lack of sufficient natural gas pipeline and LNG import capacity, and thus natural gas supply, on the coldest days. When this occurs, there can be a significant divergence between the price of natural gas at Henry Hub and the price in New England, and thus the energy price. This can also cause the substitution of oil for natural gas in the generation mix.[72]

While fluctuations in wholesale energy costs are highly correlated with fluctuations in natural gas prices, they do not line up with BED's net energy costs that are passed onto consumers in retail rates. As BED is both a generator and a load-serving entity, this adds a layer of complexity to predicting how wholesale energy and capacity prices will impact BED's cost of service. For BED, day-ahead and real-time energy settlements and forward capacity payments represent both revenues and costs.[73] For example, BED earns energy and capacity revenue from its generation resources (e.g., McNeil, Winooski One, etc.) as they deliver energy and capacity to the ISO-NE markets. Energy and capacity, however, also represent costs to BED as a load-serving entity. All things being equal, higher energy prices typically result in additional revenues for BED as a generator when BED has excess resources. However, higher prices also increase the cost to serve BED's load.

Wholesale Capacity Prices

BED expects future capacity prices to remain relatively stable over time, as shown in Figure 5-5 below. Additionally, the slope of future capacity prices remains similar to our previous IRP

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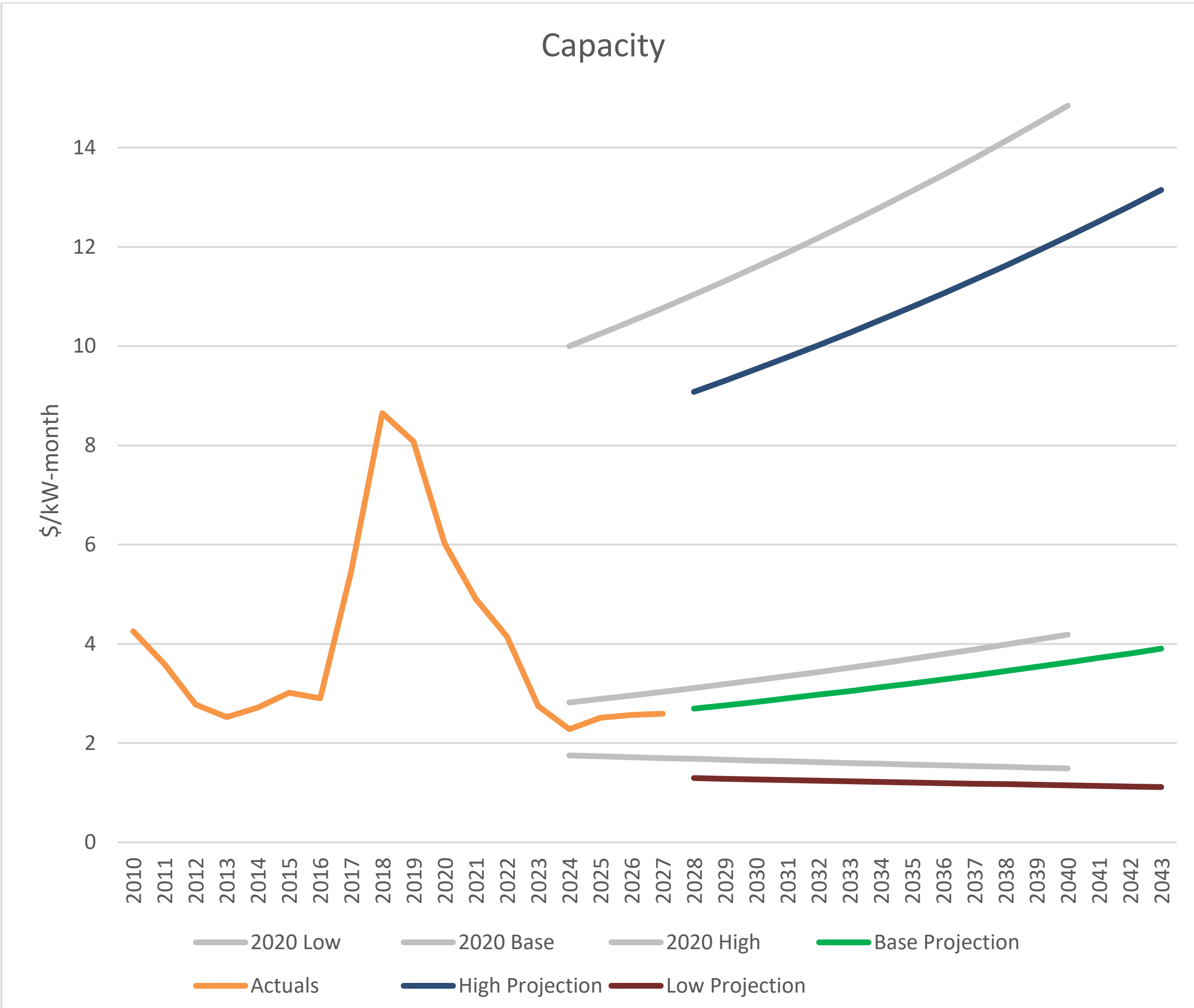
[72] https://www.eia.gov/todayinenergy/detail.php?id=51158, accessed September 2023.
[73] See Appendix B for more detail on Day Ahead and Real Time energy market rules and practices.

analysis. The starting value for the projected high case is based on September 2023 ISO-NE forward capacity auction prices. Base case projections are based on historical trends.

Figure 5-5: Capacity price forecast



As discussed in the Generation and Supply chapter, BED is capacity short by approximately 30 MW and will likely remain so over the next several years. A capacity shortfall is not uncommon for Vermont's distribution utilities. Like other Vermont distribution utilities, BED's capacity situation is a function of its energy supply's renewability, and ISO-NE's reserve margin reliability requirements. While its renewable resources may generate sufficient energy in most hours of the year, the capacity value of BED's renewable resources is de-rated in accordance with ISO-NE's market rules. Thus, BED will need to purchase additional capacity above and beyond the amount provided from BED's existing resources (primarily the McNeil plant and the Gas Turbine).

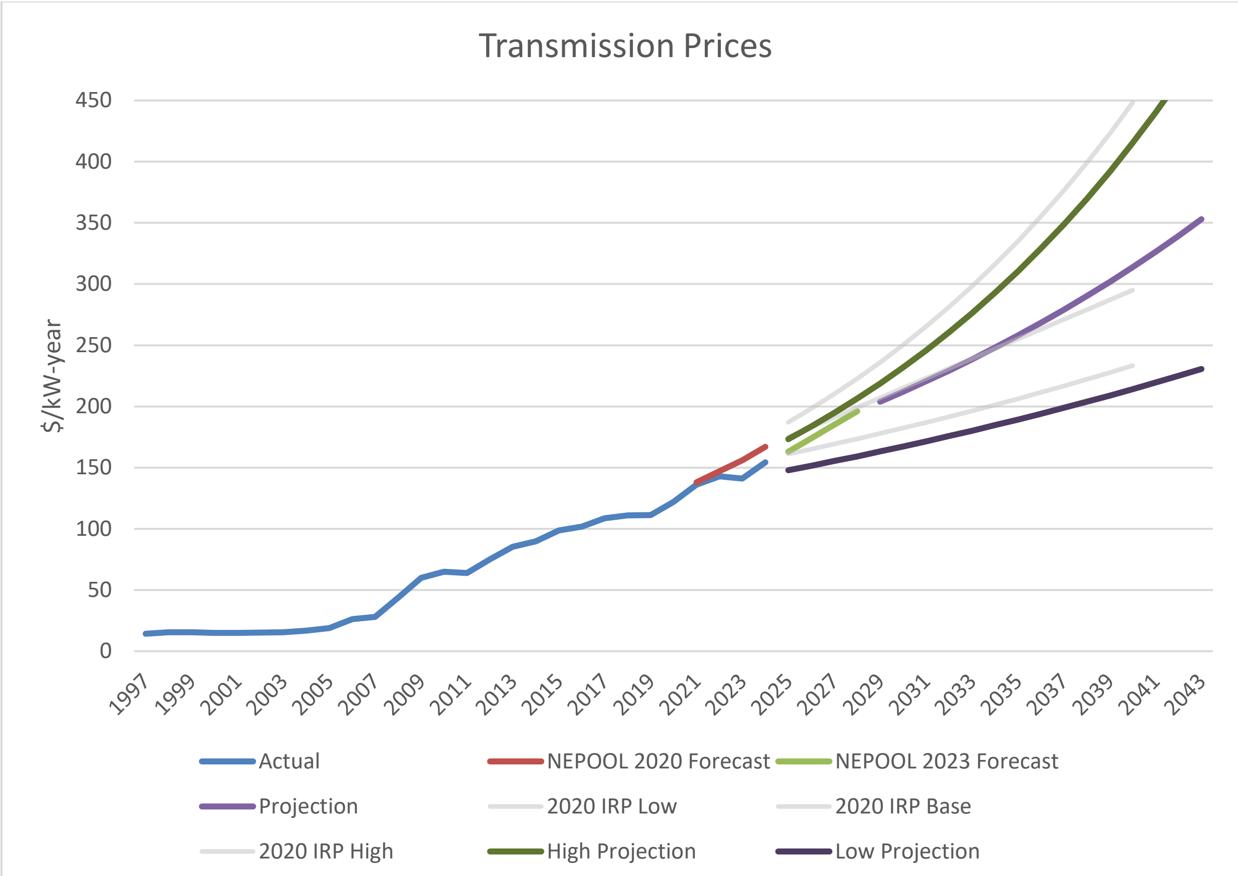
The most recent FCM auction (February 2023) cleared capacity resources at $2.59 per kW-month; capacity prices have now been under $3/kW-month for the last four auctions in the Northern New England Zone. Moving forward, BED expects capacity prices to increase at a modest rate over the IRP planning period. As existing plants are retired over time, new plants will be built and commissioned. The cost of any such new plants and changes in projected peak demand are the main determinants of future capacity prices. ISO-NE rule changes may also lead to changes in capacity costs and revenue.

As with energy costs, increases in wholesale capacity costs do not necessarily correspond with increases in retail rates because BED earns capacity revenues as a generator. Unlike with its energy, however, BED is unlikely to be able to fully offset potentially higher future capacity costs to serve load with higher capacity revenues since most of its resources are de-rated renewable resources.

Transmission Costs

BED pays for transmission services to wheel energy generated from ISO-NE–recognized resources to its customers. Such service is paid under a wholesale tariff known as the RNS and is regulated by FERC. Currently, RNS tariff rates are roughly $12 per kW-month. BED projects that RNS costs will be lower than our 2020 assessment. As shown in Figure 5-6 below, RNS costs are expected to increase to $29 per kW-month by 2043. Annually, the rate of RNS increases is estimated at roughly 4%.

Figure 5-6: Regional transmission costs

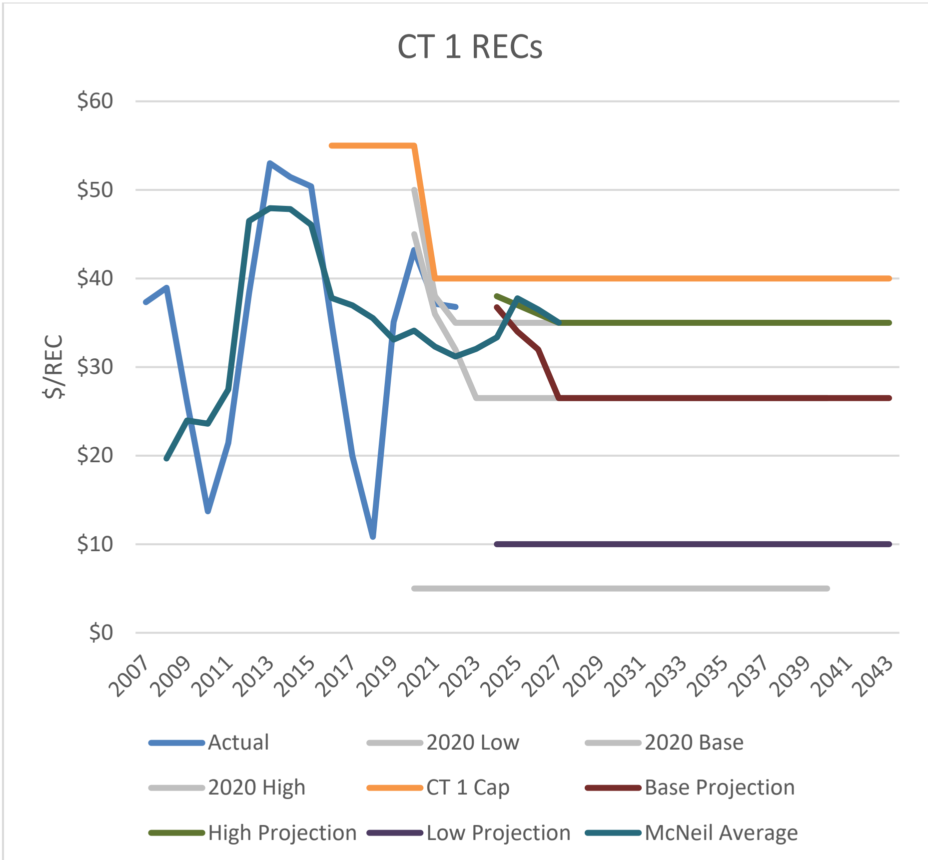


RNS cost drivers are numerous, and include replacing aging infrastructure, more stringent reliability requirements, and network congestion. Complicating matters is the difficulty in avoiding regional transmission costs, even in a future world consisting of greater amounts of distributed energy resources ("DERs"). At first glance, increases in DER assets may initially lower RNS charges but, as RNS rates are calculated based on peak load over time such reduced costs will be offset as ISO-NE increases transmission rates. Because maintaining a reliable bulk transmission infrastructure is of paramount importance and most transmission costs are socialized across the region, RNS charges are non-bypassable for New England distribution utilities, although they may be shifted between entities subject to the RNS tariff to some extent. Thus, an increase in DERs in Vermont, or elsewhere, will only result in a decrease in future transmission charges (for New England as a whole) if it postpones construction of additional transmission assets.

Renewable Energy Credit Prices

Over the 2023 IRP time horizon, BED's IRP model assumes that the price of renewable energy credits ("RECs") will average $26.50/MWh after 2026.

Figure 5-7: REC prices



BED owns the rights to sell or retire high-value RECs[74] generated from the following resources shown in Table 5-2.

Table 5-2: BED Resources and REC Market Destinations

Resource	REC market sales to…..
McNeil	Connecticut - CT1
Wind - Georgia Mtn., Sheffield, Hancock	Connecticut – CT1, Massachusetts – MA1, RI New
Winooski Hydro	Massachusetts – MA2 (non-waste)
Solar	Massachusetts – MA1

BED sells high-value RECs from owned generation, and then purchases lower cost RECs and retires them. The net proceeds from these REC sales are applied as a reduction to our costs. Thus, BED's cost of service to customers would be higher than it is today if we did not engage in this type of price arbitrage. As discussed in the Generation and Supply chapter (in the McNeil REC Status section), beginning in August 2025, McNeil will only produce 1 CT Class 1-

[74] 1 REC equals 1 MWh of electricity from qualifying facilities.

qualified REC for every two MWh it produces. The non-CT Class 1 qualified REC will, at a minimum, have value for Vermont Tier 1 compliance, and BED will continue to explore ways to maximize its value.

BED's arbitrage strategy has continued to generate net cash flow of $5-10 million annually. The continued success of this strategy depends on a stable REC market that consistently displays a generous price differential between high-value RECs (i.e., new renewable solar, wind, and other generators, etc.) and low-value RECs (i.e., older hydro facilities, etc.). Such price differentials, however, are not guaranteed into the future. Higher value REC prices are expected to decline over the next few years and could also continue to swing erratically in value as they have in the past. Meanwhile, "low-value" RECs have increased substantially. In fact, the long-term price of higher value RECs is currently uncertain; hence the wide disparity between the Low and High Projections for CT Class 1 REC prices as shown in Figure 4 above.

The price of a REC generally reflects the relative cost of developing certain types of renewable resources as compared to non-renewable alternatives. REC price volatility, however, can also be driven by regulatory uncertainties, demand for power, and the anticipated commissioning of new renewable generation facilities. Higher REC values stem from regulatory mandates requiring utilities to provide more generation from renewable sources or increase the amount of REC purchases, as this creates greater demand for existing RECs and may require development of new renewable resources. On the downside, requirements to purchase more solar power (or solar RECs) relative to other renewable resources have the effect of depressing the value of other RECs, such as those generated by McNeil. Similarly, legislation that weakens or eliminates existing renewable mandates would dramatically lower REC prices.

A few factors have caused recent uncertainty in the markets: the development of Vineyard Wind, a 800 MW offshore wind facility expected to come online in the next year that will be eligible as a Massachusetts Class 1 resource; a 1,200 MW transmission line connecting Quebec hydro to Maine that would be eligible for the MA Clean Energy Standard requirement and is expected to be complete in the next three to five years;[75] and, significant imports of New York wind continuing to be sold to load-serving entities in New England. Anything beyond those vintages is currently traded infrequently, which makes it difficult to gain a reliable evaluation of those markets. If major projects continue to come online in the next five years, a considerable decline in Class 1 RECs could result, but regulatory changes increasing state Renewable

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[75] The Massachusetts Clean Energy Standard (CES) provides most of the renewable obligation for compliance buyers in the state. Currently, Class I RECs are being retired against this obligation. The alternative compliance payment (ACP) for this standard is set to 50% of the MA Class 1 ACP, causing new influx of cheaper CES RECs to flood the market.

Portfolio Standard requirements could also increase REC prices. In the interim, a high degree of volatility is possible related to news on these projects' progress.

Due to the uncertainty about future REC values, and BED's dependence on REC revenues, REC values represent the second biggest potential impact on future rate pressure. The lack of a readily accessible market for long-term REC sales and the potential for future changes in Vermont's RES make hedging this exposure in the long term (greater than five-year window) difficult.

Non-Power Costs

Other Operating Expenses

Other operating expenses for the IRP planning period were calculated for fiscal years 2024 and 2025 based on contracted cost-of-living increases and a near-term inflation assumption of 2.5%. For fiscal years 2026-2028, labor expenses are projected to increase by 3% and non-labor expenses by 2%. For fiscal years 2029-2043, other operating expenses were calculated based on a projected long-term inflation rate of 2.25%. Using an inflation assumption was deemed appropriate for purposes of this high-level financial model.

Depreciation

The most appropriate method to forecast the depreciation expense for existing assets is based on remaining life and depreciation expense to date, layering on annual forecasted capital additions, and then calculating the additional depreciation expense for the additions based on their projected date of addition and useful life.

BED used a different approach that BED believes will achieve a materially similar result for the base case. As BED does not currently have the aforementioned method of calculating depreciation developed in a multi-year financial model, BED took the 2028 forecasted depreciation expense from the financial forecast and escalated it each year at a rate of 2.5%. As BED's weighted average depreciable life of assets is approximately 37 years, this would average approximately $5 million of capital additions each year, which is in line with BED's historical capital spend. The second step of calculating depreciation expenses requires making an adjustment to account for certain bond-financed assets on a sinking fund basis. This adjustment was done based on the actual depreciation schedules using current straight-line depreciation on those assets vs. the depreciation expense on a sinking fund basis.

Amortization

Amortization expense is largely related to BED's purchase of the Winooski One Hydroelectric facility. The difference between the fair market value purchase price and the net book value was recorded as an intangible asset and is amortized over the life of the bond financing.

Dividend Income

Dividend income is based on BED's ownership/equity shares in VELCO and Vermont Transco. Opportunities to buy additional shares, or equity calls, are driven by VELCO/Vermont Transco and its own long-term capital needs. Calendar year 2028 is the last year for which BED has received an equity call forecast from VELCO/Vermont Transco. For fiscal years 2024 to 2028, therefore, dividend income was calculated based on BED's actual and forecasted investments in VELCO and Vermont Transco. For years 2029 to 2043, an inflationary increase of 2.25% was applied. While applying inflation to dividend income is not a preferred forecasting method, due to BED's inability to predict the timing and amount of future VELCO/Vermont Transco equity calls, BED believes this approach is reasonable for purposes of this high-level analysis.

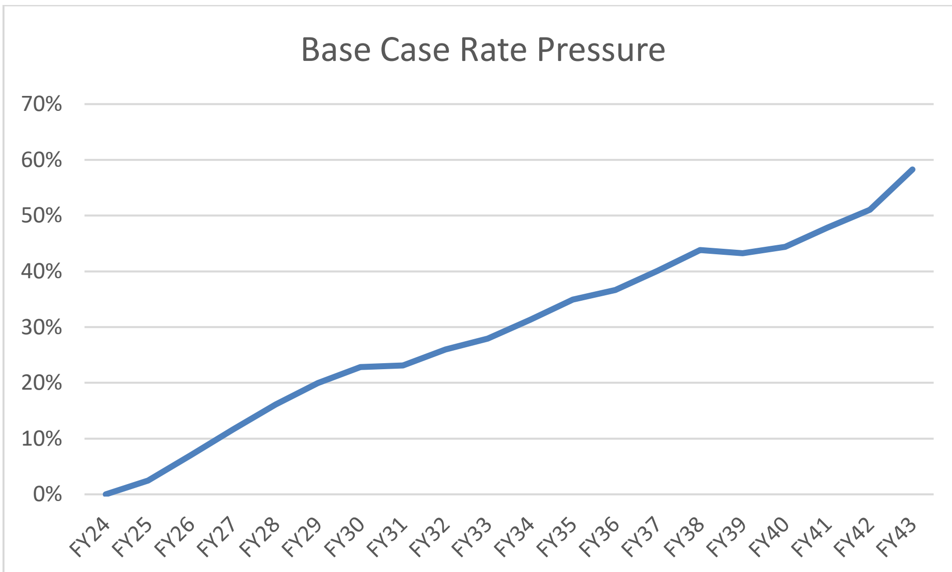
Long-Term Debt Interest Expense

For fiscal years 2024 to 2028, long-term debt interest expense was calculated consistent with the payment schedules on current obligations as well as layering on estimated annual general obligation issuances of $3 million consistent with historical interest rates. BED does not currently have a 20-year interest expense calculation built into a financial model. Thus, for years 2029 to 2043 we applied inflation to the prior year interest expense. BED evaluated the reasonableness of this calculation and deems it materially sufficient for purposes of this high-level evaluation.

Results and Base Case Rate Pressure over time

Figure 5-8 shows BED's base case rate pressure over time. Rate pressure over time is the cumulative change in average cost of service per KWH served compared to its current level. It could be reasonably expected that under normal circumstances there will be cost escalation over the 20-year period, as inflation over the previous 10-year period (2010-2020) averaged approximately 2%/year.

Figure 5-8: Rate pressure for Base Case



This forecast is most useful in comparing rate pressure differences between decisions, and rate pressure and specific annual rate increases are not synonymous. Nor is rate pressure a projection of the need for rate cases over time. As described below, changes in certain key assumptions/variables can result in a material change in rate pressure.

Key Variables Used for Stress Testing

As noted above, BED evaluates the impact of changes in key variables using "tornado charts" that illustrate the change in a specified result of a model (in this case Net Present Value Revenue Requirement or "NPVRR"). The NPVRR is the projected NPV (over five or 20 years) of BED's revenues from customers. The tornado chart illustrates the impact of changing each variable from its low to base to high case, with the center line indicating all variables are set as base case levels. For example, in the following 20-year tornado chart, the high inflation value would increase the NPVRR by $73M. Generally, if the variable reflects an income item or cost offset, the impact of the low value will be to the left (i.e., a decrease in NPVRR), and if the variable is a cost/expense, its high case value will be to the right, likewise reflecting an increase in NPVRR.

Evaluation of NPVRR results: 20-Year

As illustrated in Figure 5-9 below, the range of inflation expectations dominates all other variables in terms of risk to BED, even estimated REC values.

Figure 5-9: 20-year tornado chart showing sensitivity of NPVRR to 14 key variables

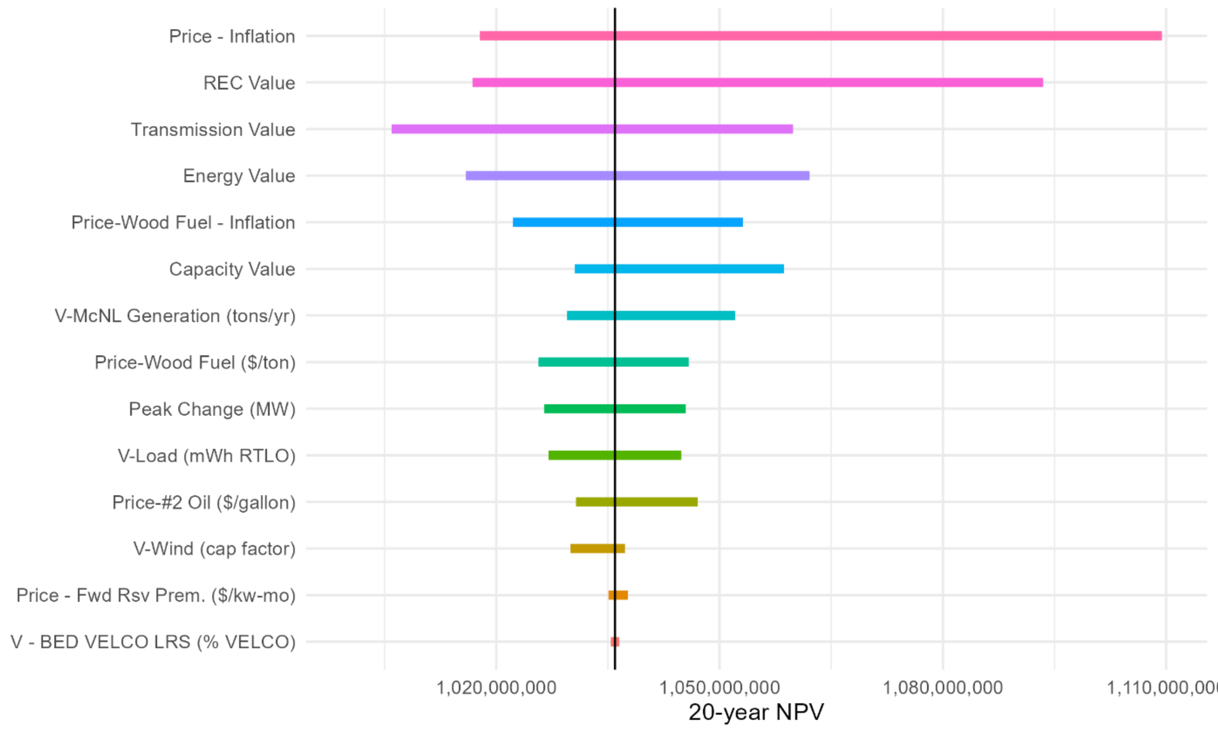


Table 5-3 compares the range of risks that individual variables impose on BED's cost of service.

Table 5-3: 20-Year Minimum, Maximum, and Max-Min Ranges

Price/Rate	Max ($M)	Min ($M)	$Max-$Min ($M)
Inflation	73	-18	92
REC	58	-19	77
Transmission	24	-30	53
Energy	26	-20	46
Wood (Inflation)	17	-13	30
Capacity	23	-5	28

The minimum potential impact of changes in inflation over the next 20 years is a reduction in expenses of $18 million, but the maximum impact could be an increase of $73 million. The difference between these two assumptions amounts to $92 million. This analysis indicates that inflation represents the most significant risk to BED's cost to serve its customers. over time.

Evaluation of NPVRR results: 5-Year

Over the next five-year horizon, REC prices represent the greatest risk, despite BED having pre-sold RECs over next five years.

Figure 7: 5-year tornado chart showing sensitivity of NPVRR to 14 key variables

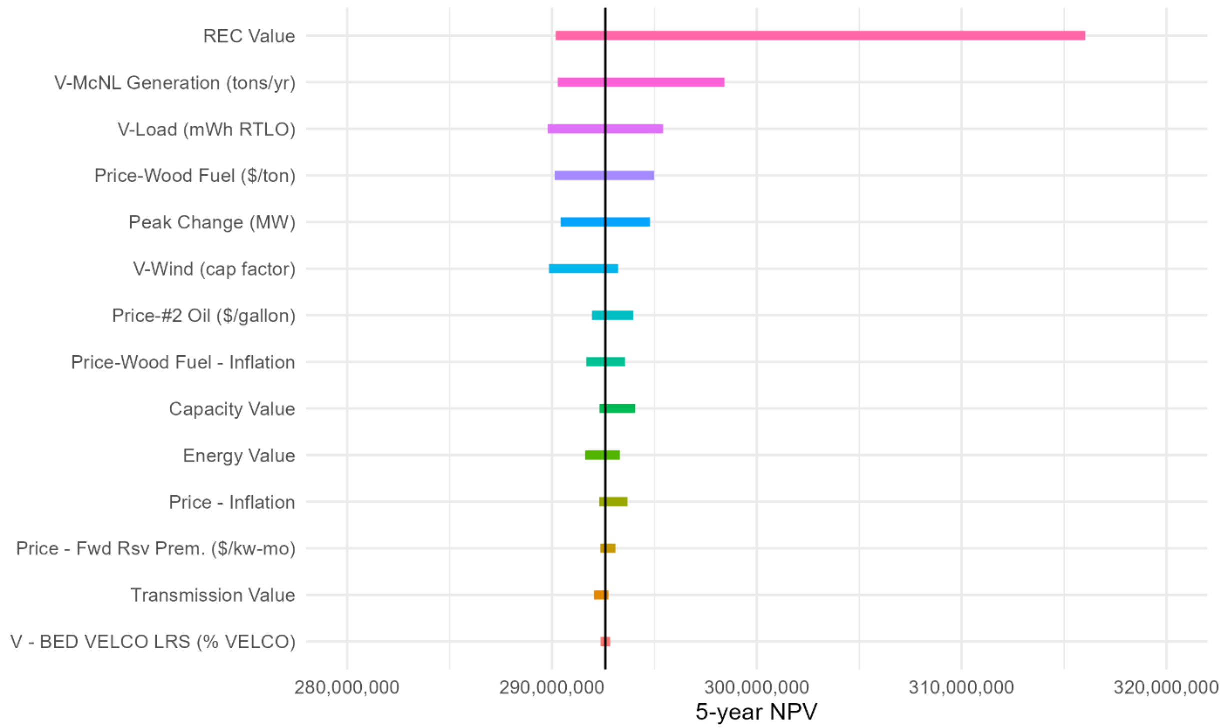


Table 5-4 compares the range of risks that individual variables could impose on BED's cost of service.

Table 5-4: 5-Year Minimum, Maximum, and Max-Min Ranges

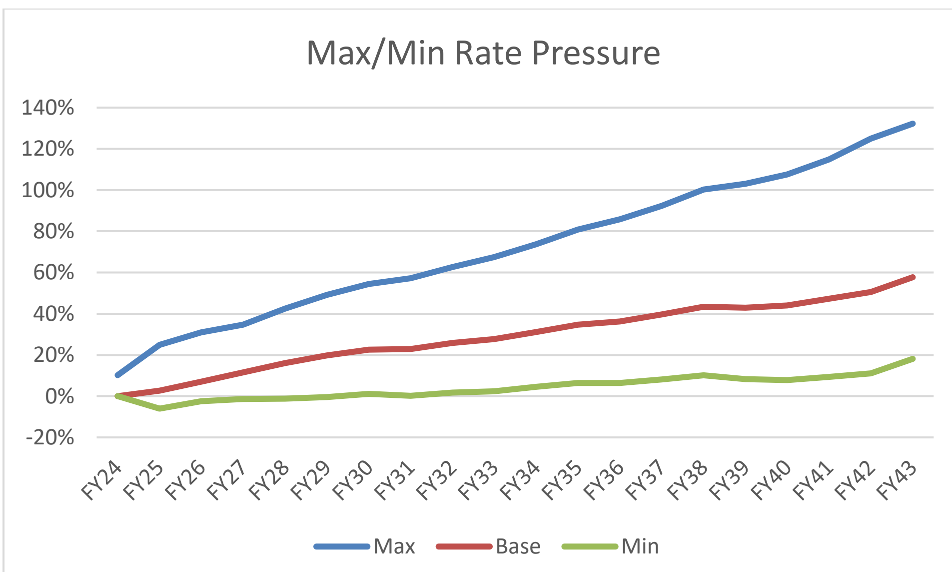
Item	Max ($M)	Min ($M)	$Max-$Min ($M)
REC Price	23	-2	26
McNeil Generation	6	-2	8
Load (MWh)	3	-3	6
Wood Price	2	-2	5
Load (MW)	2	-2	4

The minimum potential impact of changes in REC values over the next five years is a reduction in expense of $2 million, but the maximum impact could be an increase of as much as $23 million. The difference between these two risk profile scenarios is $26 million. This analysis indicates that based on the ranges assigned to REC prices by BED staff, REC prices are the single most significant risk that BED faces in the medium term. In addition, a number of the variables have shifted (or dropped off) compared to the 20-year analysis, showing that over the medium term, energy-related risk is less about the price of energy than the quantity of energy captured in this analysis.

Results & Range of Potential Base Case Rate Pressure Due to Key Variables

Different combinations of key variables change the level of pressure on BED's rates over time. Figure 5-10 shows the potential range of rate pressure outcomes that can result from changes in the assumptions around the aforementioned key variables. The "Max" line in the figure below represents BED's assessment of the direction and magnitude of potential rate increases (or upward rate pressure) assuming all of the key variables trended toward the worst case scenario (whether that is low REC prices or high capacity prices). The "Min" line represents the opposite. As shown below, the compounding effect of changes in variables could place a significant amount of pressure to increase rates in the future, even with the substantial hedging BED currently undertakes with respect to energy and RECs. On the other hand, the lowest potential pressure on rates would result from sustained high REC prices.

Figure 5-10: Range of Rate Pressure Scenarios with Worst Case (Max) Base Case, and Best Case (Min)



This financial model will continue to evolve, as new information is gathered and as improvements are made to the model. This financial analysis is a helpful tool for planning, decision-making, and decision comparison as we look out over a 20-year horizon.

Five-Year Budget Forecast

In addition to the long-range IRP financial model, BED maintains and annually updates a five-year budget forecast model. This model forecasts net income, cash flow, cash coverage (days cash on hand), revenue bond debt service coverage ratios, and adjusted debt service coverage ratio. The five-year forecast includes assumptions and projections for major revenue and expense categories, other income and deductions, capital spending, and financing, as shown in Table 5-5 below.

Table 5-5: Five-Year Forecast Assumptions

Variable	Assumption
Sales to Customers revenues	Itron forecast for 2023 IRP; annual rate increases in the range of 2% to 5.5%
Power supply revenues and expenses	2023 power supply forecast
Capital spending	See 5-Year Capital Plan, below
Cost of living adjustments to salaries	FY24 budget / 4% / 3% / 3% / 3%
Labor overhead inflation	FY24 budget / 4% / 3% / 3% / 3%
General inflation for other O&M	FY24 budget / 2.25% / 2.25% / 2% / 2%
New debt financing	\$20M tax-exempt revenue bond (20-yr) issued 2025; principal deferred for 5 years \$5.46M taxable revenue bond (20-yr) issued 2025
Interest rate on new debt	4% tax-exempt; 5% taxable
Line of credit	Increasing from \$5M to \$10M beginning FY 2026

Pro Forma Income Statement

Table 5-6: Pro Forma Income Statement

	Budget FY 24	Forecast FY 25	Forecast FY 26	Forecast FY 27	Forecast FY 28
OPERATING REVENUES:					
Sales to Customers	$53,110	$56,719	$59,363	$61,460	$63,566
Misc Revenues - Power Supply	8,244	8,467	8,903	7,328	5,280
Misc Revenues - Other	3,775	3,874	3,963	4,048	4,135
Total Operating Revenues	65,130	69,060	72,229	72,836	72,981
OPERATING EXPENSES:					
Fuel	9,546	10,455	10,364	10,810	11,136
Purchased Power	14,618	16,698	17,779	17,433	17,094
Transmission Expense	9,717	10,055	10,264	10,584	11,063
Operation and Maintenance	22,846	23,684	24,429	25,183	25,965
Depreciation & Amortization	6,630	5,886	6,068	6,257	6,431
Gain/Loss on Disp of Plant	296	300	304	308	318
Taxes	3,369	3,587	3,782	3,969	4,163
Total Operating Expenses	67,021	70,665	72,990	74,544	76,170
NET OPERATING INCOME	(1,891)	(1,605)	(762)	(1,708)	(3,189)
OTHER INCOME & DEDUCTIONS:					
Dividends	4,402	4,578	5,107	5,107	5,107
Interest Income	462	270	214	214	224
Grants/Capital Contributions	428	878	878	685	685
Other Income, Net	48	48	48	48	48
Total Other Income/Deductions	5,340	5,774	6,247	6,054	6,065
INCOME BEFORE INTEREST EXPENSE	3,449	4,169	5,485	4,347	2,876
INTEREST EXPENSE	3,166	3,068	3,787	3,786	3,607
NET INCOME (LOSS)	$283	$1,102	$1,698	$561	($731)

5-Year Capital Plan

BED's five-year forecast includes a capital plan to support continued investment in BED's distribution system, generation facilities, technology infrastructure, public EV charging stations, vehicle fleet replacement, and buildings.

Table 5-7: Five-Year Capital Plan

Summary	Approved Budget FY24	Forecast FY25	Forecast FY26	Forecast FY27	Forecast FY28
Generation					
McNeil Plant (50% Share)	1,233,998	1,376,333	2,623,950	1,675,394	1,700,198
Gas Turbine Plant	458,374	73,300	923,300	998,800	1,805,800
Hydro Plant	317,938	989,500	652,204	556,790	445,472
Distribution Plant *(1)*	7,550,307	4,424,008	3,777,143	3,648,291	2,878,227
Transmission Investment (VELCO)		5,640,000			
Information Technology	450,981	1,363,104	1,597,013	373,468	68,000
Other					
Demand Reponse	26,042	107,121	107,720	60,600	61,226
General Plant *(2)*	474,091	762,832	769,536	752,400	718,900
Total Plant	$10,511,731	$14,736,198	$10,450,866	$8,065,743	$7,677,823
CAFC (Customer Contribution/Grant Income *(3)*	428,434	878,060	878,060	685,200	685,200
Total Plant - Net	**$10,940,165**	**$15,614,258**	**$11,328,926**	**$8,750,943**	**$8,363,023**
RES Tier 1 REC Inventory	$350,000	$3,605,000	$3,651,000	$3,659,000	$3,649,000
RES Tier 3 (Strategic Electrification) Inventory	$1,127,339	$1,305,924	$1,506,885	$1,725,120	$1,960,237
Total RES Inventory Additions	**$1,477,339**	**$4,910,924**	**$5,157,885**	**$5,384,120**	**$5,609,237**

(1) Includes public EV charging stations.
(2) Includes vehicle replacements.
(3) CAFC of $684,200 for FY25 and FY26 estimated based on 3-year average. Grant income of $192,860 in FY25 and FY26 based on budget for State of Vermont Energy Storage Access Project grant award.

Pro Forma Cash Flow (Sources & Uses of Funds)

This five-year forecast also helps BED to plan for financing its capital needs, with sources of funds including cash reserves/net income, debt financing, customer contributions, and grants. No refinancing of debt is planned in the near-term due to the current elevated interest rate environment, but BED is considering a second tranche of the $20 million Net Zero Energy revenue bond issued in April 2022. Funds from the 2022A revenue bond will be available for expenditure through April 2025, and in 2021 BED had initially estimated a need of $40 million for infrastructure investments to enhance reliability and support progress towards our City's energy and climate goals. A second tranche of approximately $20 million issued in spring 2025 is modeled in BED's current five-year forecast to fund further investments in grid reliability and capacity, upgrades and refurbishments of renewable energy facilities, investments in electric charging infrastructure and fleets, and other items. Issuance of the new debt would be contingent upon approval by Burlington voters, potentially in November 2024.

BED is also considering options for financing additional equity investments in VELCO/Transco, to best align cash flow from dividends with cash expenditures for the additional equity. VELCO/Transco equity provides a strong return on investment, but also requires cash. BED is planning to become a strategic member of Vermont Public Power Supply Authority (VPPSA), a joint action agency for municipal public power utilities in Vermont, which would enable BED to join in VPPSA's financing of VELCO equity in a cash flow positive manner. This would not require BED to incur any new debt. VPPSA would take on the debt and use the equity dividends to repay the debt, with the surplus dividends provided to participating utility members. Longer-term, BED is evaluating the issuance of taxable revenue bonds to support further VELCO/Transco investments coincident with the potential 2025 issuance of additional non-taxable revenue bonds in spring 2025.

Lastly, BED maintains a $5 million line of credit for working capital. BED has never needed to use the line, and plans to continue that practice, but it provides flexibility and supports a key liquidity (days cash on hand) metric. The line of credit has not been increased commensurate with BED's operating budget, nor has it kept up with inflation, since it was first established circa 2007. BED is planning to bring a request to City Council for a Town Meeting Day (March) 2024 ballot item to enact a charter change (subject to voter approval, and subsequent legislative approval) to increase BED's line of credit from the current $5 million to $10 million.

Table 5-8: Pro Forma Cash Flow (Sources & Uses of Funds)

	Approved Budget FY24	Forecast FY25	Forecast FY26	Forecast FY27	Forecast FY28
BEGINNING BALANCE	$4,680	$7,813	$9,658	$10,550	$11,512
SOURCES OF FUNDS:					
Total Operating Revenues	65,130	69,060	72,229	72,836	72,981
Other Income					
Dividends	4,402	4,402	5,107	5,107	5,107
Interest and Other Income	510	318	262	262	272
Customer Contribution/Grant Income	428	878	878	685	685
Total Other Income	5,340	5,598	6,247	6,054	6,065
Other Sources of Funds					
GOB Annual/BAN	3,000	3,000	3,000	3,000	3,000
2022A Revenue Bond	9,182	4,358		0	0
2025A Revenue Bond - non-taxable	0	3,415	7,119	5,584	3,945
2025B Revenue Bond - taxable	0	5,640			
Total Other Sources of Funds	12,182	16,413	10,119	8,584	6,945
TOTAL SOURCES OF FUNDS	87,332	98,885	98,252	98,025	97,503
USES OF FUNDS:					
Total Operating Expenses	53,471	55,902	57,112	58,015	59,084
Tier 1 Purchases-cash only	350	3,605	3,651	3,659	3,649
Tier 3 Total-RPS Compliance Exp & Cash	1,127	1,306	1,507	1,725	1,960
IBEW Pension back payment	147				
Taxes - Gross	3,369	3,587	3,782	3,969	4,163
Net Operations Expenses	58,464	64,400	66,052	67,368	68,856
Capital Spending					
BED	10,129	8,598	8,705	7,076	6,663
McNeil	1,262	1,376	2,624	1,675	1,700
VT Transco, LLC	0	5,640	0	0	0
Total Capital Spending	11,391	15,614	11,329	8,751	8,363
Debt Service					
G.O. Bonds	5,820	6,056	6,103	6,191	6,325
Revenue Bonds	3,518	2,831	4,076	4,079	4,911
Other (MDMS Lease & Moran Frame)	325	325	141	124	124
Total Debt Service	9,664	9,213	10,320	10,394	11,360
TOTAL USES OF FUNDS	79,519	89,227	87,702	86,513	88,579
ENDING BALANCE - OPERATING	**$7,813**	**$9,658**	**$10,550**	**$11,512**	**$8,924**

Pro Forma Financial Metrics

BED is rated by Moody's, which upgraded BED's credit rating to A3 (stable) in December 2016 and has affirmed this rating annually since then. Moody's rating factors for financial strength and liquidity are (1) adjusted days liquidity on hand (days cash on hand, 3-year average), (2) adjusted debt service coverage ratio (3-year average), and (3) adjusted debt ratio (3-year average). In addition, BED's general bond resolution requires BED to maintain a revenue bond debt service coverage of at least 1.25. BED's current projections are shown below for all of these ratios except the debt ratio, which is unavailable because BED does not forecast a balance sheet.

Table 5-9: Pro Forma Financial Metrics

Metric	Approved Budget FY24	Forecast FY25	Forecast FY26	Forecast FY27	Forecast FY28
Days cash on hand	90	95	126	129	112
Adjusted debt service coverage ratio	1.11	1.15	1.17	1.09	0.89
Adjusted debt ratio	NA	NA	NA	NA	NA
Revenue bond debt service coverage ratio	3.68	4.59	3.59	3.45	2.63

6. Decision Processes

Objective

Achieving BED's overarching twin objectives (i.e., 30 V.S.A. § 218c compliance and helping Burlington transition to Net Zero Energy) will be challenging given the multiple known and unknown risks about the state of our economy, post-COVID demand for electricity, public health, technology, regulations, and wholesale market prices for energy, capacity, transmission, and RECs. A decision process that adequately recognizes and accounts for such a range of future risks is critical. In this chapter, we describe our process for evaluating risks and making decisions using Behind-the-Meter ("BTM") storage as an example. In this context BTM is used to mean behind the ISO-NE meter, not the retail customer meter. Another way to say this is storage that is not recognized in the wholesale markets as an asset.

Our objective in providing the example analysis below is to describe to the Commission our analytical methods for identifying and evaluating the known risks associated with a utility-scale energy BTM storage system in Burlington. We then explain how BED would decide whether to proceed with such an investment based on the best currently available information. After the detailed BTM example, we discuss the decision tree methodology that we would use in the context of a series of choices that may need to be made concurrently.

Burlington's (and Vermont's) goals are currently focused on reducing the many adverse impacts of climate change. However, with BED already having achieved a 100% renewable energy supply in 2014, and with BED's goal of meeting its Tier 3 RES obligation with electrification programs rather than by simply buying RECs, the remaining policy work to meet Vermont's climate goals will in large part be done outside the electric utility space. BED will just be one party among many to these decisions. BED will continue to model potential impacts of new ordinances, statutes, and rules and the work done in this IRP positions us well to do so. As noted elsewhere in this IRP, BED is presently evaluating one plausible, forward-looking scenario: an NZE future, as discussed in greater detail in the Net Zero Energy Chapter.

Sample Single Decision Analysis: BTM Energy Storage

To illustrate BED's decision-making process, a sample energy storage power purchase agreement ("PPA") for a 5MW/20MWh lithium-ion battery located in Burlington is analyzed below. Older methods of energy storage have long been a resource upon which New England has relied in the form of nearly 2 GW of pumped hydro capacity[76] that has been balancing the

[76] Bear Swamp and Northfield Mountain.

grid for over 40 years. At present, there is a revival of interest in new storage installations in the form of numerous customer-sited battery storage installations and larger utility-scale facilities. ISO-NE has 18 GW of storage in its interconnection queue. This increase in storage installations has been driven by recent energy storage price declines for battery storage, as well as an anticipated need for additional storage due to increasing intermittent generation.[77] Likely, some of the increase in proposed storage is due to the tax incentives in the Inflation Reduction Act. BED has been exploring storage opportunities for several years and has modeled a "sample storage project" for the analysis that follows.

This potential project would be "behind the meter" from ISO-NE's perspective, so ISO-NE would not control it for the purposes of energy dispatch, but it would be "in front of the retail meter" from BED's perspective as it would not be behind a customer meter.

Project Cost

The bulk of the modeled project costs are associated with a PPA, with lesser costs related to the electricity use to recharge the battery (including losses incurred in the charging/discharging cycle, which are assumed at 15% for this project). This raises an interesting note: battery storage is not a generator, it is a net consumer of electricity, but it does create the potential to move energy, at an energy "cost," to times of greater need. To the extent that recharging can occur at time of low demand or excess energy, this trade is non-problematic.

Project Value

The value of a battery storage project would depend upon how its charging and discharging would be managed. The value of each use can be further categorized as: the value of a particular use or "value stream," ability to capture that value stream, and the impact on BED's risk profile (due to BED's exposure to risks associated with that value stream). The Transmission, Frequency Regulation, Capacity, and Energy value streams are examined in detail below as the primary value streams that can be realized under current ISO-NE market rules. Battery projects might provide additional value streams in the future, which would be incorporated into future project analyses (or which might take the place of current value streams).[78]

There could be conflicts between what is needed to realize two or more value streams simultaneously. For example, a battery discharged for an anticipated ISO-NE peak hour might not be available to discharge again for a Vermont peak hour that occurred later the same day.

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[77] https://irtt.iso-ne.com/reports/external, Accessed October 2023

[78] https://rmi.org/wp-content/uploads/2017/03/RMI-TheEconomicsOfBatteryEnergyStorage-FullReport-FINAL.pdf, accessed August 2020.

Transmission Value Stream (ISO-NE RNS)

By discharging the battery during the hour of Vermont's monthly peaks, under current treatment of loads, BED would reduce its pro rata share of transmission charges that are based on those peaks because energy discharged locally from the battery would lower BED's recognized demand. The amount of societal value that BED could create through those discharges is less clear because those transmission costs would still be paid by other market participants. If the reduction in BED's (and more importantly ISO-NE's) load that resulted from battery discharges during monthly peaks postponed the need for development of additional regional infrastructure, the societal savings could be relevant and material, but the transmission deferral value of a particular project on RNS investments and carrying costs would be difficult to estimate.

Price/Value

As discussed in the Financial Assessment chapter, RNS transmission costs have approximately quintupled from 2005 to 2023, and the IRP forecasts that they will continue to increase. The current price of transmission approximately equals the analyzed cost of the analyzed PPA option. To the extent that BED can reliably predict and discharge the battery during each monthly peak, the transmission savings alone would almost cover the bulk of the project costs. BED assumed that the battery system would discharge during nine out of every ten transmission peaks. This impact of this assumption could be tested in future modeling.

Availability

Transmission savings would be achieved by discharging the battery during the Vermont monthly peak hour. Since late 2018, BED has been using a model to predict VT and ISO-NE peak load. It is possible that as DERs capable of flattening Vermont and regional loads are deployed, predicting the peak and when to discharge a battery will become more difficult. Continued deployment of solar will continue to lower loads when the sun is out, making peak prediction somewhat easier (as many daylight hours will be less likely to be the peak).

Risk Profile Impact

BED is a buyer but not a seller of ISO-NE transmission services because these charges are assessed under a tariff structure to load-serving entities vs. a locational buy-sell market structure (as with energy, capacity, and regulation, among others), so any action that reduces transmission usage and costs will reduce our exposure to RNS price fluctuations.

Frequency Regulation (Automatic Generator Control) Value Stream

Market participants can earn Frequency Regulation (or Automatic Generator Control ("AGC") revenue by allowing their assets to be controlled on a second-by-second basis by ISO-NE to balance small changes in supply and demand on the grid.[79] BED currently incurs regulation charges based on its share of ISO-NE's hourly load. A BTM storage resource could register with ISO-NE as an Alternative Technology Regulation Resource for the purpose of providing regulation while still not being a market-recognized asset. This value stream would be available to BED due to the battery being in New England and greater than 1 MW.

Price/Value

The price of regulation services is difficult to predict. The increase in intermittent resources could result in additional regulation services being procured by ISO-NE, likely increasing the regulation price. Currently, ISO-NE is procuring less than 100 MW of regulation service on average,[80] and with more than 18 GW of battery storage in ISO-NE's queue, it seems likely that the number of potential suppliers of this service will grow such that the revenue received for providing it will fall to the marginal cost of providing it with a battery under the existing auction based pricing structure. If the value of AGC services were to fall to that level, BED and others would not receive any additional net revenues as the value of providing the service would equal the cost of providing it. As shown in Figure 6-1, the size of the regulation market has remained small relative to the billions of dollars that are exchanged for energy and capacity in New England every year.[81,82]

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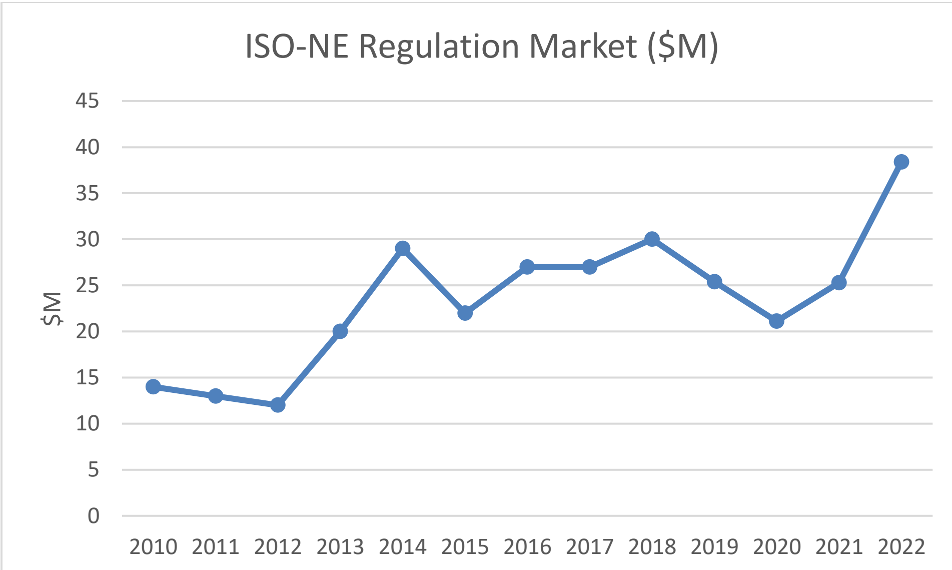
79 https://www.iso-ne.com/markets-operations/markets/regulation-market/, accessed August 2020
80 https://www.iso-ne.com/static-assets/documents/2023/06/2022-annual-markets-report.pdf, accessed October 2023
81 https://www.iso-ne.com/static-assets/documents/2017/04/20170411-webinar-energy-storage.pdf, accessed August 2020
82 https://www.iso-ne.com/static-assets/documents/2023/06/2022-annual-markets-report.pdf, accessed October 2023

Figure 6-1: ISO-NE Regulation Market Revenues



Availability

This AGC value stream would be available to BED whenever the battery was not being used for other purposes. Using the battery for the AGC value stream may conflict with the battery's use for greater value stream propositions in some cases.

Risk Profile Impact

Deploying a storage asset of this size would reverse and increase BED's exposure to AGC price fluctuations by making BED a net supplier relative to its AGC needs. BED is currently only a buyer of AGC services (i.e., 100% short), having no assets capable of providing those services to the market and is adversely affected when prices for the service increase. With the proposed storage project, BED would become substantially (~300%) long (i.e., a net seller of the AGC service) and therefore adversely affected by falling AGC prices, if it were providing 4MW (5MW * 80% assumed availability) of average service to ISO-NE.

Capacity Value Stream

Under current rules, by discharging the battery during the hour of ISO-NE's annual peak, BED would reduce its pro rata share of capacity charges that are based on those peaks. The amount of societal value that BED would be able to create through those discharges is perhaps lower, as the immediate impact could be to shift those costs to other market participants. However, the reduced load would likely lead to ISO-NE taking actions to "offload" excess capacity in the periodic reconfiguration auctions and less capacity being procured in future FCAs. ISO-NE could adjust future capacity auction procurements, as with EE and BTM solar, by directly modeling the impact of BTM storage in its forecast of required capacity.[83]

Price/Value

Currently capacity represents the second-largest value stream available to the proposed storage project (after RNS transmission). The price of capacity has fallen in the last five ISO-NE capacity auctions, but it remains a significant cost driver for BED. Capacity prices are essentially known through May 2027 but could vary substantially in the future. In addition to the direct reduction in peak load at the ISO-NE hour, if a BTM battery is discharged at that time additional savings would occur in the form of the reserves that would not be incurred (i.e., capacity purchased by ISO-NE in excess of projected peak load for reliability reasons). BED assumed that the battery would discharge in 29 out of 30 capacity peaks.

Availability

BED has consistently been able to identify capacity peaks (i.e., the hour that will ultimately be determined to have been the ISO-NE peak hour for the year) both in its prior demand response program with EnerNOC and its current Defeat the Peak program.[84] While this market has changed several times in the relatively recent past, no current discussion is occurring that would remove the availability of the capacity value stream, but as noted above the price is uncertain.

Risk Profile Impact

BED is currently "short" capacity (see Generation & Supply Chapter) and will be adversely affected if capacity prices increase in future FCAs, so any action that reduces that exposure will reduce our risk exposure to price increases, as long as BED does not add so much capacity that it becomes a net provider of capacity to ISO-NE (which would not be caused by a storage asset of this magnitude).

Energy Value Stream

BED could create energy arbitrage value from an energy storage project by charging during low-priced times and discharging during high-priced times, reducing its net energy charges. This can create value if the differences in energy prices between the discharge and charge times are sufficient to justify incurring the energy losses incurred in the cycle. To the extent that discharge times for capacity and transmission might not always coincide with the highest price energy times, there could be some overlap between this value stream and the others. Energy

[83] https://www.iso-ne.com/system-planning/system-plans-studies/celt/, accessed October 2023
[84] http://burlingtonelectric.com/peak, accessed October 2023

arbitrage value would probably be subordinated to the transmission and capacity value streams but would be available on days where the probability of a peak was low.

Price/Value

Although energy prices vary on a five-minute basis in the ISO-NE wholesale markets, on most days they do not vary greatly, and as a BTM resource this resource would be settled hourly with BED's load. Accordingly, the price assumption is based on BED's existing forecasts of on-peak and off-peak price spreads.

Availability

This analysis assumes that the energy arbitrage would occur around attempting to lower peak costs and, specifically, that on-peak energy usage would be reduced by 400 hours * 5 MW or 2,000 MWh per year.

Risk Profile Impact

BED is projected to be longer (or less short) in the "x16" hours (7:01am-11pm) than in the "x8" hours (11:01pm-7am) through 2035. As the battery would likely shift load from the x16 hours to the x8 hours, it would exacerbate this issue. That said, given the small net impact to BED's energy position (through round-trip and standby losses), and the general price difference between these periods, BED is not likely to be taking on significantly more, or shedding much, energy price risk. Additionally, if there are hours with higher and lower prices, a battery operator or management program can act on them whenever they occur, not just in the ISO-NE defined "peak" and "off peak" periods, thus reducing BED's negative risk exposure to real time price spikes provided state of charge permits.

Results

As part of its examination of the storage project, BED performed a cost/benefit comparison of the project at our high, base, and low variable values to the project's costs. This comparison showed that the project would have little impact on BED's NPVRR at our expected prices of the value streams but would be substantially profitable at higher prices of those streams. A series of sensitivity tests were performed, showing that the project would generally reduce BED's risk to capacity and transmission market fluctuations because of the reduction in our capacity shortfall and transmission exposure. Additionally, potential rate pressures were calculated with and without the project, showing the main financial impacts to be in the 2030s due to continued projected increases in transmission prices.

Cost/Benefit

To perform the cost/benefit tests, BED added a storage-specific "mini-model" to our standard IRP 20-year financial model. BED then looked at the value of the hypothetical project at each of the high, base, and low values for the major value streams identified. This showed the most significant potential value streams of the battery project to be transmission cost (with the provisos about cost-shifting versus societal savings noted above). Energy arbitrage is smaller and less likely to be a major driver of the project's economics unless the spread between the highest and lowest prices in a day widens or some form of new market were introduced that attempted to reduce energy imbalance. The cost/benefit analysis also revealed that there is a wide range to the potential economic benefits or costs, given unknown future market prices—particularly that of capacity.

Figure 6-2 and Figure 6-3 below illustrate the five- and 20-year cost/benefit analyses. The five-year analysis is presented to consider the impacts during the period where the capacity prices are relatively certain and market changes are less likely. The effect of the current three-year forward capacity structure can be seen more clearly in the reduced range of potential capacity revenues between the three cases. Note that BED has not been offered a five-year arrangement under a PPA, but one of the theoretical advantages of storage is its modularity and relative ease of deployment (both of which potentially argue against deploying unneeded storage materially in advance of it becoming economical).

Figure 6-2: 20-Year NPV

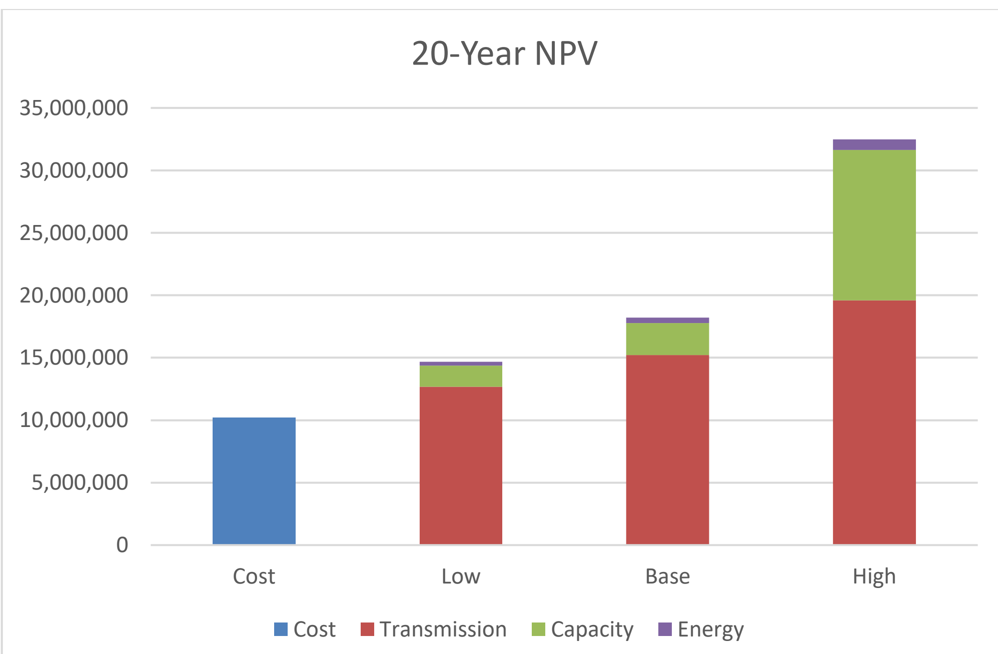
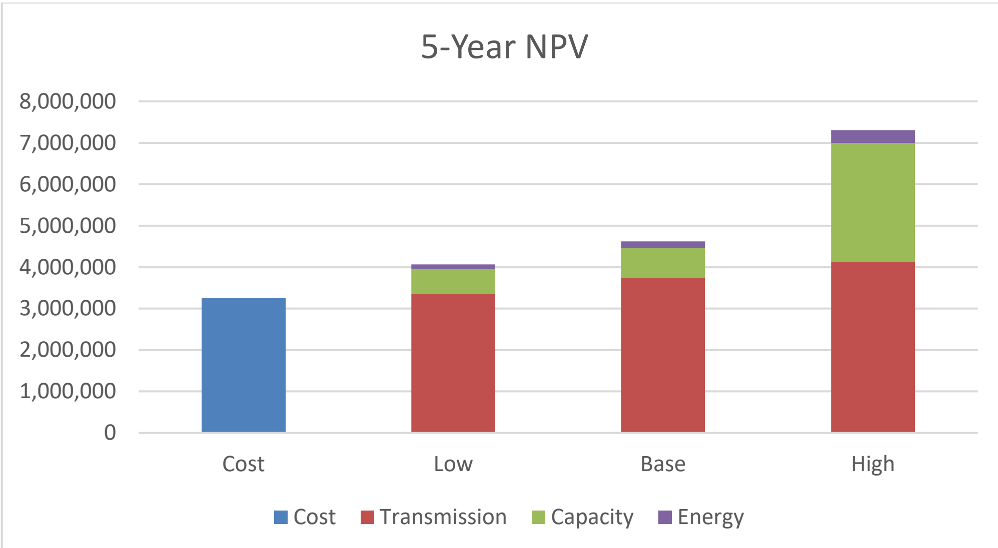


Figure 6-3: 5-Year NPV



Sensitivities

To perform the sensitivity tests, BED calculated the NPV of our five- and 20-year cost of service without storage (i.e., the NPVRR). The resulting tornado charts (Figures 6-4 through 6-7) show a comparison of the NPVs with low, base, and high values for each variable. Based on these charts, it appears that this project would reduce BED's risk of exposure over the 20-year horizon to swings in capacity prices by 24% and transmission prices by 8%.

Figure 6-4: 20-Year Tornado Chart with Battery Storage

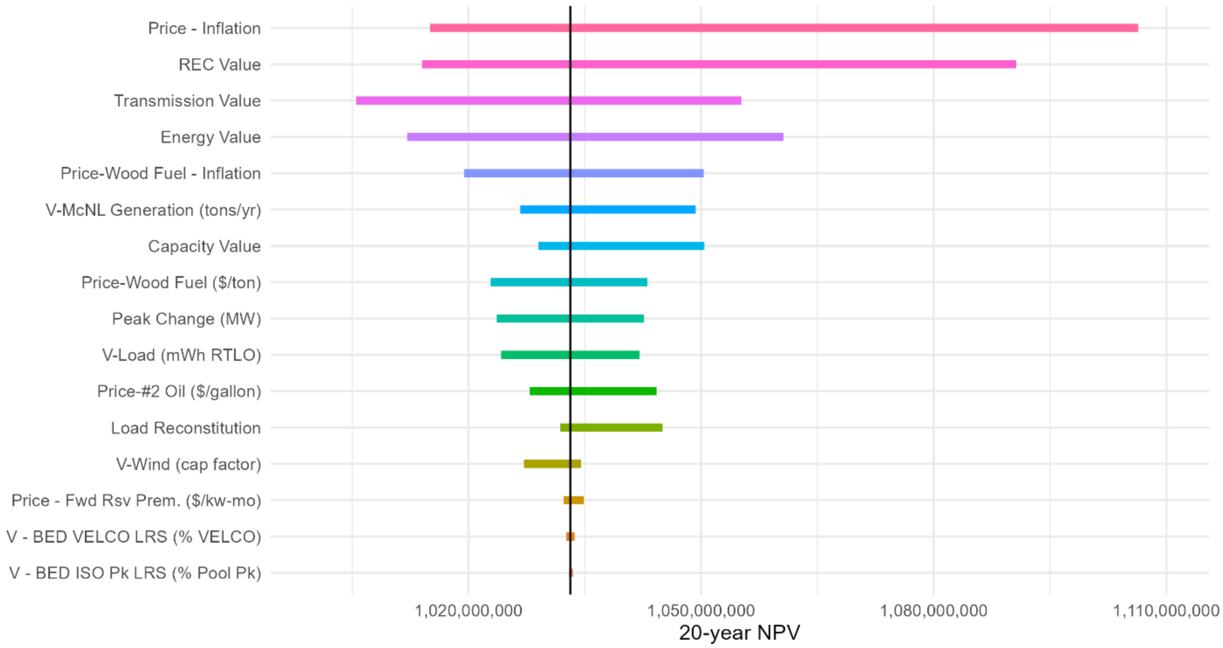

Price - Inflation
REC Value
Transmission Value
Energy Value
Price-Wood Fuel - Inflation
V-McNL Generation (tons/yr)
Capacity Value
Price-Wood Fuel ($/ton)
Peak Change (MW)
V-Load (mWh RTLO)
Price-#2 Oil ($/gallon)
Load Reconstitution
V-Wind (cap factor)
Price - Fwd Rsv Prem. ($/kw-mo)
V - BED VELCO LRS (% VELCO)
V - BED ISO Pk LRS (% Pool Pk)
1,020,000,000
1,050,000,000
1,080,000,000
1,110,000,000
20-year NPV

Figure 6-5: 20-Year Base (No Storage) Tornado Chart

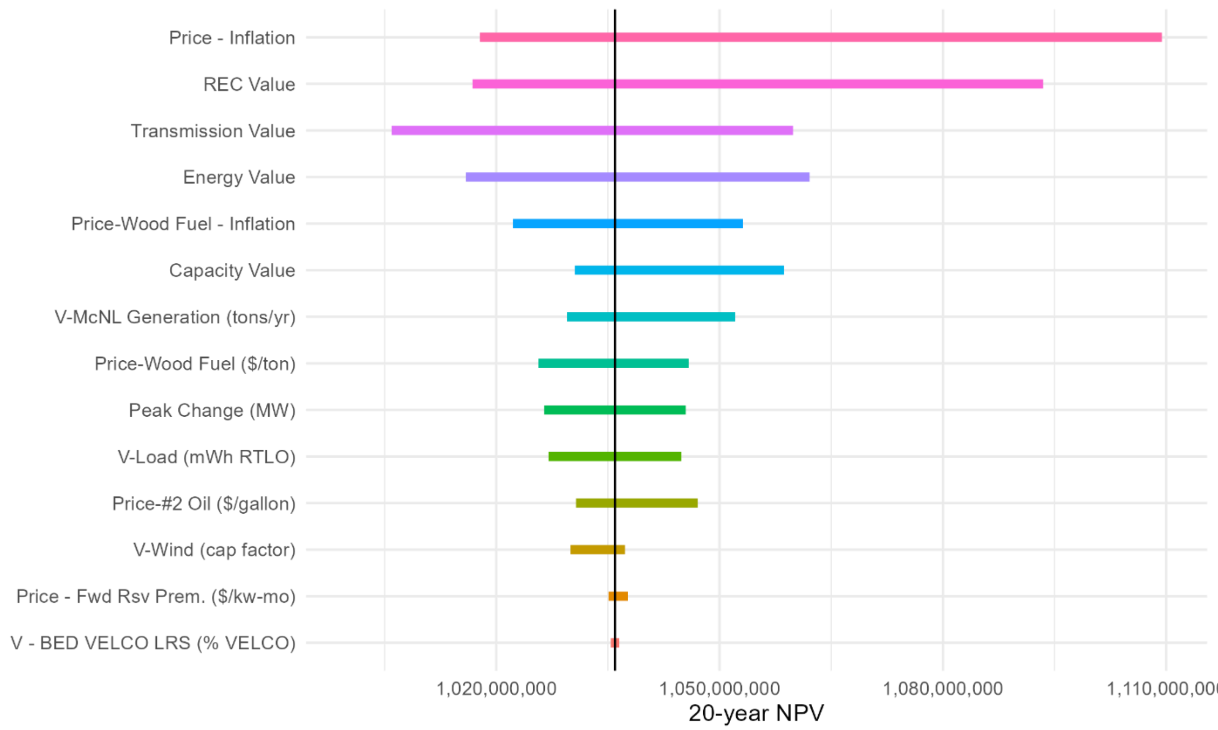


Figure 6-6: 5-Year Tornado Chart with Battery Storage

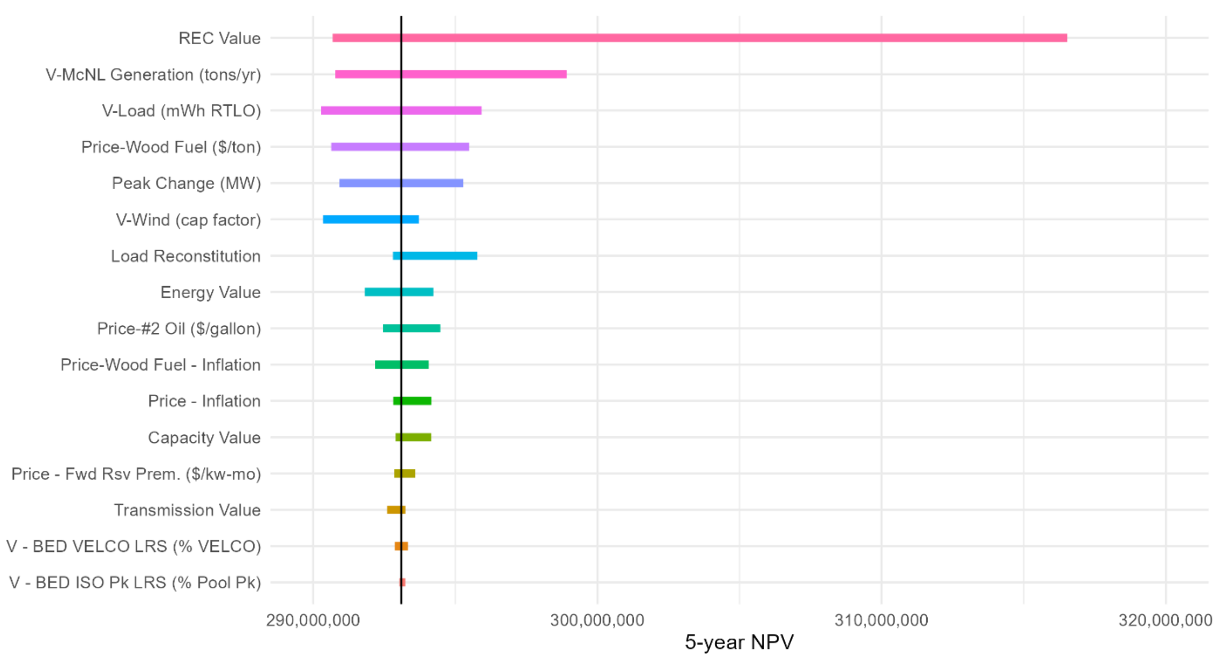
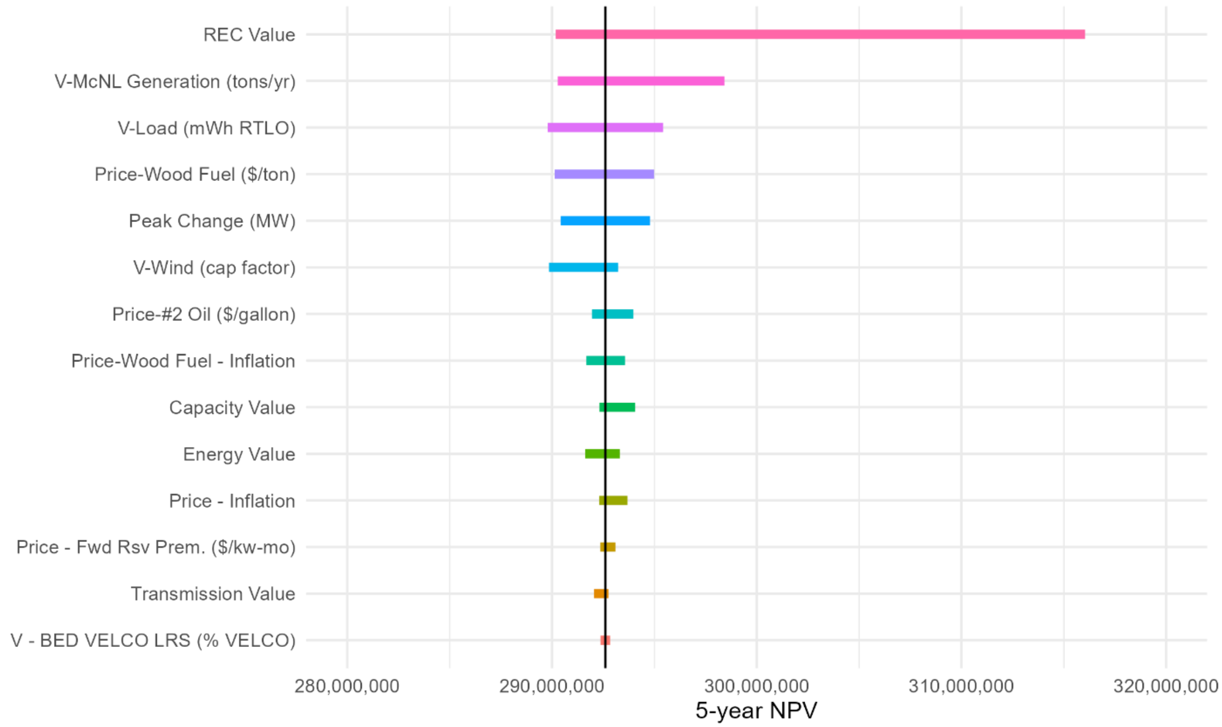


Figure 6-7: 5-Year Base (No Storage) Tornado Chart



In addition, as shown in Table 6-1, the spread of values between the two PPA options and the "do nothing" option shows a shrinking of transmission and capacity risk.

Table 6-1: Delta between Low Transmission and Capacity Prices Case v. High Transmission and Capacity Prices Case ($000)

	5-year	20-year
Base (No Storage)	2,451	82,028
Storage	1,898	71,075

Potential Rate Pressure

Finally, illustrative potential rate pressures (as well as the difference between those rate pressures) were calculated with and without the project. As shown in Figure 6-8 and Figure 6-9, the project will not be the main driver of rates going forward but could mitigate rate pressure in the 2030s.

Figure 6-8: Rate Pressure Impact

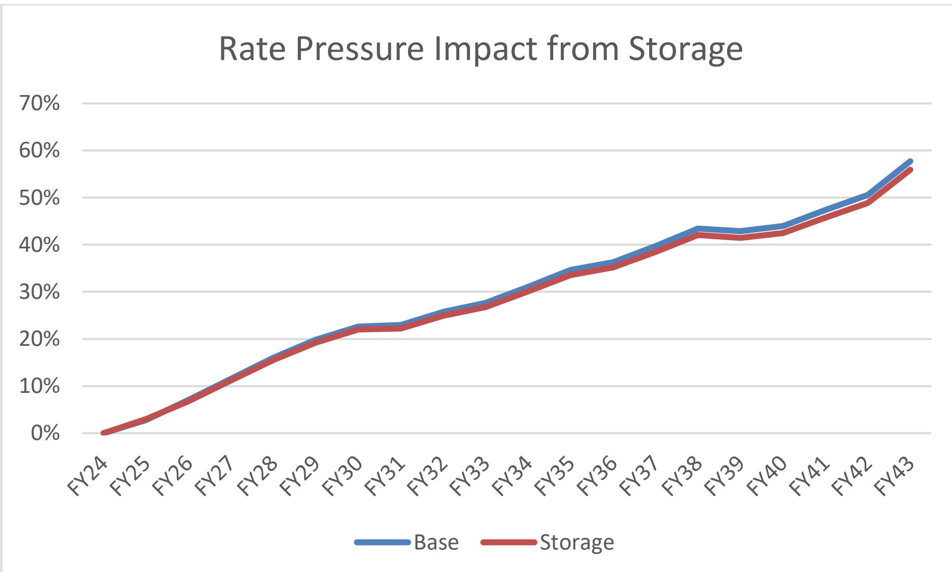
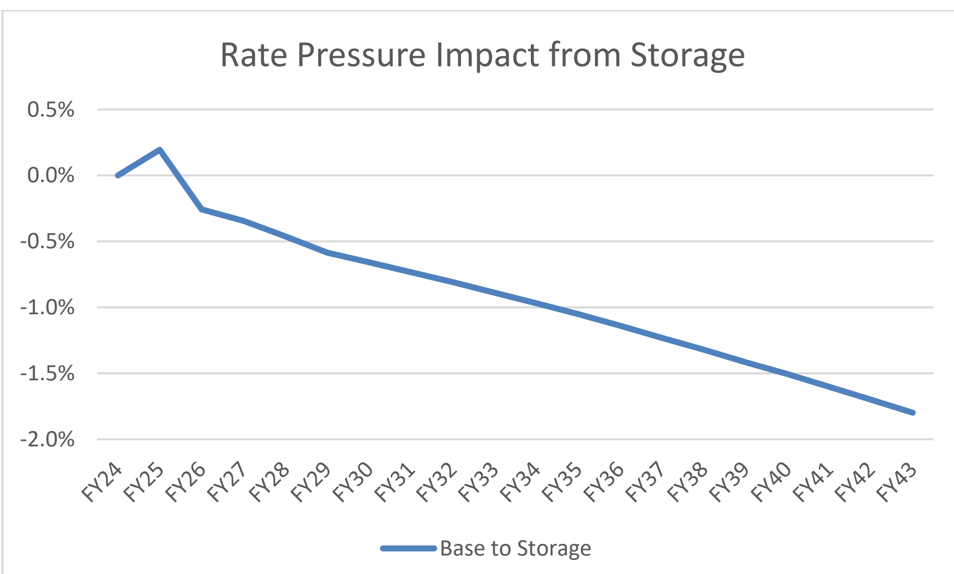


Figure 6-9: Relative Rate Pressure Impact



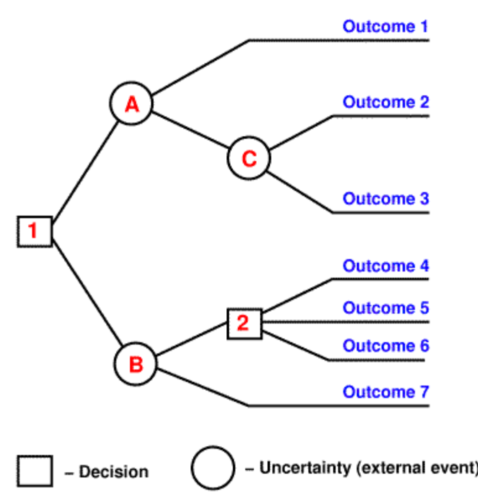
Conclusion

As shown above, a single decision can be analyzed several ways. This analysis of a sample storage project showed that it would have different impacts on BED's bottom line as well as different societal impacts depending on future prices, the availability of value streams, and PPA terms. Between the 2020 IRP and this one, the generic storage that we evaluated became more economic under our base case. Clearly, storage requires continued attention going forward, especially as the price of battery storage is expected to continue to fall. If the FCM market were changed or future FCM clearing prices began to increase, BED would want to reexamine and potentially battery storage economics. Depending on the PPA price structure, if the cost and benefit streams could be aligned to avoid front end rate impacts for long term benefits, battery storage could be deployable in the near future (i.e. before the next IRP is due).

Decision Tree Methodology

On occasion, BED will want to evaluate multiple competing decisions at the same time. A decision tree analysis is a reliable business tool that allows for systematic processing of several input variables or risks that must be evaluated to reach conclusions and make decisions. At its most basic level, a decision tree analysis is a stepwise evaluation of known variables that could materially affect a business's operations if they are not appropriately managed. Figure 6-10 at left highlights such steps, the sequential interactions between decisions and risks, and the plausible outcomes that may follow.

Figure 6-10: Decision Tree Illustration

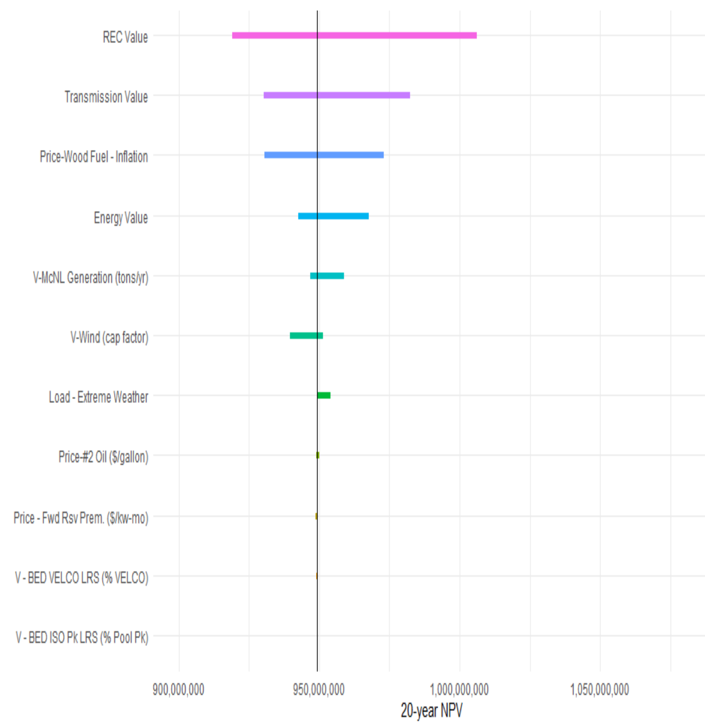


At the start of a decision tree analysis, input variables and other external factors that could impose material risks on decision outcomes are identified.

BED uses tornado charts to further inform its decision tree analyses by graphically highlighting how known risks could impact our cost of service, or NPVRR. As shown in Figure 6-11 below, known risks are listed along the vertical axis and the 20-year NPVRR is highlighted along the horizontal axis. The color-coded bars display the range in probability of occurrence of select risks and their corresponding range of impact on BED's NPVRR. In this example, wood fuel inflation is the fourth highest-risk factor because the likelihood of it occurring in the future is speculative (i.e., the wider the bar, the wider the range of probability of occurrence). Similarly, the range of potential impacts caused by higher-than-normal escalating wood prices on BED's

NPVRR is considerable. Through this process of charting individual risk profiles and their potential NPVRR impacts, BED can assess the sensitivity of our NPVRR to various known risk factors. Knowing how sensitive NPVRR is to such risks will inform the identification of potentially important paths in any future resource procurement decision.

Figure 6-11: Example Tornado Chart of Risk Impact on NPVRR



Next, BED assigns a probability of occurrence between 0 and 1 based on the best available information. This risk assignment process is typically performed by management and staff responsible for developing project plans. After each team member assigns their probability of occurrence to a specific risk, a range of potential outcomes for the risk can be determined. For example, one team member could assign the likelihood of higher than forecasted inflation (e.g., 5%) a score of 0.90. Another member could assign the same risk a score of 0.10, indicating that higher than forecasted inflation is unlikely to occur anytime soon. This assignment process reveals that inflation not only has the potential to materially impact operations, but the range of such impacts could potentially swing by 80% in one direction or the other. Such a wide range in probability of occurrence also means that inflation is a high-risk factor that needs to be tracked and managed carefully over time.

To reflect BED's decision-makers' view of risks facing BED, input variables are then weighted to arrive at a weighted-average risk profile. If, for example, two staff members assign the risk of high inflation a score of 0.90 and four staff assign a score of 0.1, then higher than forecasted inflation rates have a 36.67% chance of occurring over the planning horizon. By weighting known risks in this manner, management can gain better insight into the impact on BED of the potential future states that are of the most concern. For example, a consistent weighting of the high energy value by BED decision-makers would indicate concern that the current energy market conditions are not sustainable. This "weighted case" does not replace, but is additional to, the other cases as a point of discussion along with any non-monetary and risk related considerations. These steps of this iterative process are repeated until a reasonable decision path comes into view. At any point the project can also be examined based on a given decision makers view of the future.

The step of creating a "weighted" case was omitted in the above storage analysis only because of time constraints and lack of an instant decision for action. Given the range of results, creation of a weighted case would not have been likely to change the conclusion reached however.

To summarize, the decision tree process leading to the development of BED's tornado charts follows a series of key, iterative steps. These include:

- identifying, evaluating, and modeling key input variables;
- assigning probability of occurrence scores to key input variables, and calculating their weighted average expected probabilities;
- conducting NPVRR sensitivity analyses;
- identifying and examining answers to key questions that may impact BED's overall mission;
- evaluating plausible scenario outcomes; and
- refining decision tree scenarios and re-evaluating outcomes, as needed.

Conclusion

BED considers any major decision through many "lenses." This chapter walked through a sample decision and described the decision tree process for evaluating multiple simultaneous decisions. At this point, BED continues to pursue its Net Zero Energy goal but does not have any major decisions where action is imminent regarding which preferred path to evaluate.

7. Net Zero Energy Roadmap Update

In 2018, the City of Burlington announced its goal of becoming a Net Zero Energy ("NZE") city by 2030. BED subsequently adopted this goal as its strategic direction, and in September 2019 published a *Net Zero Energy Roadmap for the City of Burlington* ("Roadmap") that outlines specific pathways and recommendations for Burlington to accomplish its goal.

> Net Zero Energy is defined as reducing and eventually eliminating fossil fuel consumption in the building and ground transportation sectors by substantially increasing energy efficiency and then switching the remaining fuel to renewably sourced electricity.

The Roadmap provides a comprehensive assessment of the total annual energy consumption in Burlington under business as usual ("BAU") conditions,[85] and describes two alternative scenarios and timelines for achieving a fossil fuel free community: one by 2030 ("NZE30"), the other by 2040 ("NZE40"). This section provides an update on Burlington's progress toward the Roadmap, which was described in the previous IRP in 2020.

BED's involvement with the City's NZE efforts began many years ago with securing renewable energy resources; in 2014 BED became one of the first electric utilities to be 100% renewable. These efforts continue and include meeting BED's Tier III obligations under the RES with a robust array of electrification programs (rather than with RECs). Fully eliminating fossil fuel use from the heating and ground transportation sectors will require significant future investments by BED (and other stakeholders) in programs, measures, distribution upgrades, load control capability, and technical assistance. The level of annual investment is estimated to be significantly greater than the current funding directed at BED's energy efficiency utility. This gap originally was forecasted to grow, but may have been partially closed by recent changes in available federal and state incentives for some electrification measures (the impact of which have not been quantified in the context of Burlington's Net Zero Roadmap as yet).

Although BED is a leading participant in the City's NZE efforts, the goal cannot be achieved by BED's actions alone. Additional efforts to support NZE include new City policies requiring weatherization in rental properties buildings and strategic electrification in new buildings. Partnerships with other City Departments as well as key external partners such as Champlain Valley Weatherization Services, VGS, Green Mountain Transit, and others will play an important role.

[85] A copy of the full Roadmap report is attached and can also be found at: burlingtonelectric.com/nze

In some cases, federal or state policy changes may be required. A state policy example is Vermont Act 151 of 2020 which was extended by Vermont Act 44 of 2023. Act 151 provided BED (and other authorized efficiency utilities) with additional flexibility to redirect existing electric efficiency funds toward GHG reduction initiatives. Still other potential policies identified in the NZE Roadmap that are not directly in BED's control include carbon pricing, developing a transit plan, and changing land use patterns.

The Clean Heat standard may also provide additional funding source but the details of its implementation and interaction with Tier III remain to be determined. BED is actively engaged with local, state, and federal officials regarding activities and potential funding to advance NZE, but we have not obtained significant additional funding sources beyond those identified in other chapters of this IRP. Grants applied for (and in some cases received), will assist, but probably not dramatically change, deployment rates of electrification measures in forecast terms.

Therefore, for the purposes of this IRP, BED assumes that adoption of beneficial electrification technologies, such as electric vehicles and heat pumps, will not occur at a significantly different pace than our BAU scenario until specific policies are enacted. Instead of planning for an NZE30 or NZE40 future, BED assumes that adoption of beneficial electrification measures will mirror national trends to ensure resource adequacy and reliability are maintained, pursuant to 30 V.S.A. § 218c. The BAU modeling outputs do serve, however, as the starting point for evaluating the potential impacts of an NZE future, which we further describe below.

This Chapter provides a high-level assessment of the potential implications of achieving different stages of the Roadmap. Specifically, this chapter discusses:

- Roadmap assumptions and outputs;
- Expected distribution system impacts at 102.8 MW and 120 MW;
- Expected power supply requirements at 102.8 MW and 120 MW;
- Preliminary revenue impacts at 102.8 MW and 120 MW; and
- Whether the sum of the above would tend to increase or decrease BED's average cost per KWH of providing electric service ("rate pressure") in both scenarios.

Net Zero Energy Roadmap Overview

Reaching the NZE goal by 2030 will require a paradigm shift in how Vermont designs clean energy programs (either with aggressive incentives, state mandates, or both). Achieving the goal also will require some modification of Burlingtonians' current energy consumption habits. At a minimum, successfully attaining NZE depends on:

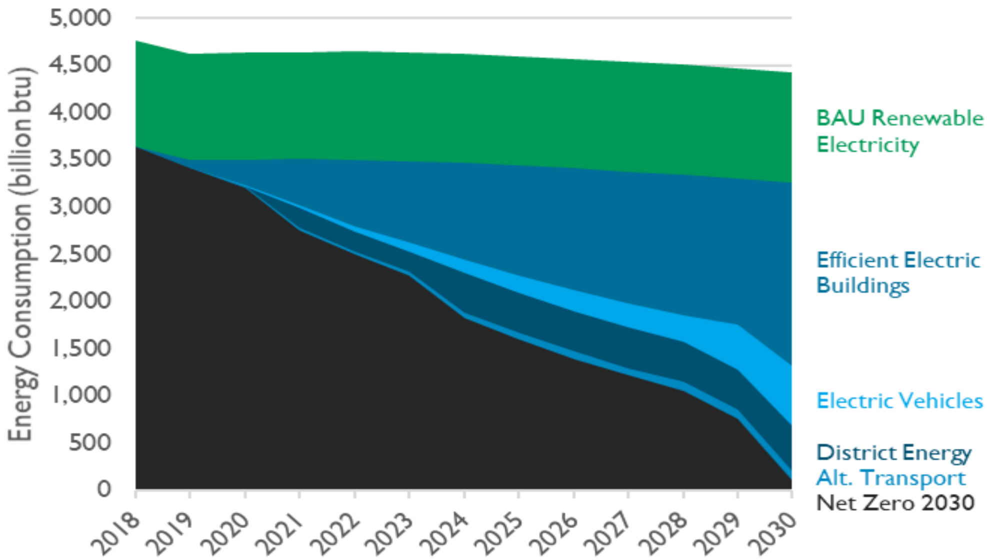
- Substantial reductions in energy use through accelerated and integrated energy efficiency, particularly in the thermal sector;
- Widespread active and passive demand response in the form of rates and programs designed to limit system impacts to the greatest extent possible;
- Expansion of the distribution system's capability to serve new loads reliably, prior to those loads coming online;
- Comprehensive itywide planning for all new construction projects and major renovations, including renovations of historic buildings to avoid retrofit needs at later dates;
- Widespread adoption of beneficial electrification technologies, such as heat pumps and electric vehicles;
- Maintaining our 100% renewably sourced electricity generation portfolio; and,
- Stakeholder support and engagement among all of BED's partners.

In short, the NZE goal requires an "all-hands-on-deck" effort to fully transform two large market sectors that are fundamentally important to the state and local economy: building thermal energy needs and transportation. The main tools that BED can currently leverage to work toward accomplishing the NZE goal are the RES, especially our Tier III obligations; rate design that leverages demand response to reduce operational costs; and our EEU programs.

To provide guidance to the community and other decision-makers on how Burlington can attain NZE, BED commissioned the NZE Roadmap to establish a City-wide total energy consumption baseline. This baseline consumption, which amounts to over 4,500 billion BTUs, including renewably generated electricity, serves as the starting point toward the NZE goal. The Roadmap identifies the energy uses that need to be de-carbonized and the implementation "trajectories" required to accomplish the goal by different dates.

By determining the amount of decarbonization that is needed by generic end use, the Roadmap provides insight into how Burlington can begin the process of reducing fossil-fuel consumption by switching to renewably sourced electricity or reducing energy consumption. As Figure 7-1 shows, fossil-fuel consumption (black-shaded area) is replaced over time with renewable electricity (green- and blue-shaded areas). To successfully "bend down" the fossil-fuel consumption curve, the Roadmap directs Burlingtonians to four pathways to NZE: efficient electrically heated buildings; electric vehicles; district energy; and alternative transport. Each pathway includes a set of goals, which are explained further below. The magnitude of the potential fossil-fuel savings by pathway is shown in varying shades of blue in the graph. Ror transportation sector purposes, only trips by Burlington residents are counted in the Roadmap, although there will be a secondary focus on reducing fossil-fuel use by visitors and commuters to the City. As loads are converted from fossil fuel in each sector, that energy will need to be powered by increasing the current amount of renewably sourced electricity (depicted in green).

Figure 7-1: Burlington's Total Energy Consumption



Pathway 1: Efficient Electric Buildings

Customers will need to dramatically shift from traditional heating systems (e.g., hydronic boilers and hot air furnaces fired by fossil fuels) to new advanced heat pump technologies for space conditioning and domestic hot water.

Air-source heat pumps ("ASHPs"), also referred to as cold climate heat pumps ("CCHPs"), are currently the main renewable technology in Vermont capable of providing sufficient heating capacity, except during extreme cold temperature events. With current technology, Vermonters typically maintain their existing conventional heat source in addition to ASHPs or CCHPs to ensure their building is safe and comfortable during such extreme cold weather. A significant number of CCHPs have been installed throughout Vermont in the past several years and in addition to providing heat, provide air conditioning in the summer. It is expected that the number of CCHP installations will continue to increase, even under our BAU scenario. But in the Roadmap, their adoption is more rapid, as further discussed below.

While residential heat pump adoption rates have steadily increased in Vermont, the customer's economic incentive for installing a CCHP in Burlington remains limited. Within BED's territory, more than 95% of customers have natural gas heat systems. Because natural gas prices are at low levels, it generally costs less to heat with natural gas than with a CCHP at present retail electric rates. Therefore, most BED customers will not achieve energy cost savings by switching from natural gas heat to a CCHP system (though for customers wishing to decarbonize their heating load, CCHP technology does compete favorably with the cost of heating with renewable natural gas, which is priced significantly higher than traditional natural gas). Many customers, however, may be interested in CCHPs not only for heating, but also for their efficient cooling capability.

While the economics of CCHP adoption in Burlington are challenging, the NZE30 modeling outputs would require installation of heat pump technology in all new buildings by the mid-2020s.[86] To facilitate extensive heat pump adoption among existing building owners without an increase in the price of natural gas (either due to a market increase or due to an explicit carbon adder), BED would need to do one or more of the following:

1. Continued support from incentives above those currently permitted under the Vermont RES (such as are permitted by Act 44 of the 2023 session, and recent federal and state incentives)
2. Take action to encourage such conversions at the City government level
3. Offer reduced electric rates for CCHPs, particularly those that are load-controlled.[87]

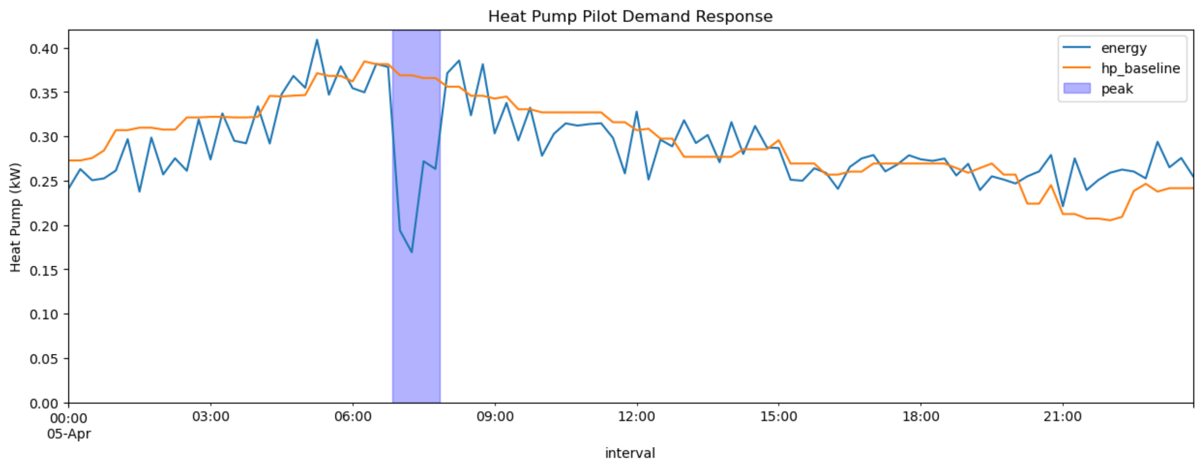
Over the next two to four years, BED will need to closely monitor changes in the pattern of electric use and the City's progress toward heating all buildings and domestic hot water with heat pumps. BED will have to monitor the number of annual and cumulative heat pump installations and simultaneously encourage building owners to increase the thermal efficiency of their buildings by weatherizing the building shells, air sealing, and, in some cases, replacing windows and/or doors. Research into end-use metering and load control options may support special CCHP rate options. Having the capability to control heating and cooling loads from CCHPs – especially for buildings that are weatherized – will minimize the impacts of heat pumps on our distribution system and resource requirements.

BED is in the process of completing a CCHP flexible load management pilot focused on evaluating its ability to accurately submeter and dynamically manage peak demand through thermostatic setpoint adjustments. This work is partially funded by a grant from the PSD under the Flexible Load Rate Design Pilot Projects and concludes at the end of September 2023. BED plans to continue to gather data on CCHP behavior and flexibility beyond the timeline of this pilot work. Results from this work remain preliminary and will provide key inputs into the ability to achieve an end-use CCHP rate economically and technically. One finding, provided in

[86] In addition to the most widely adopted CCHP technologies, other heat pump technologies include ground source heat pumps ("GSHPs"), water-to-water heat pumps, air-to-water heat pumps, and variable refrigerant flow ("VRF") heat pumps for commercial applications.
[87] However, providing CCHP rate credits would have the effect of reducing the benefits of widespread beneficial electrification on rate pressures. For more information, see Chapter 5.

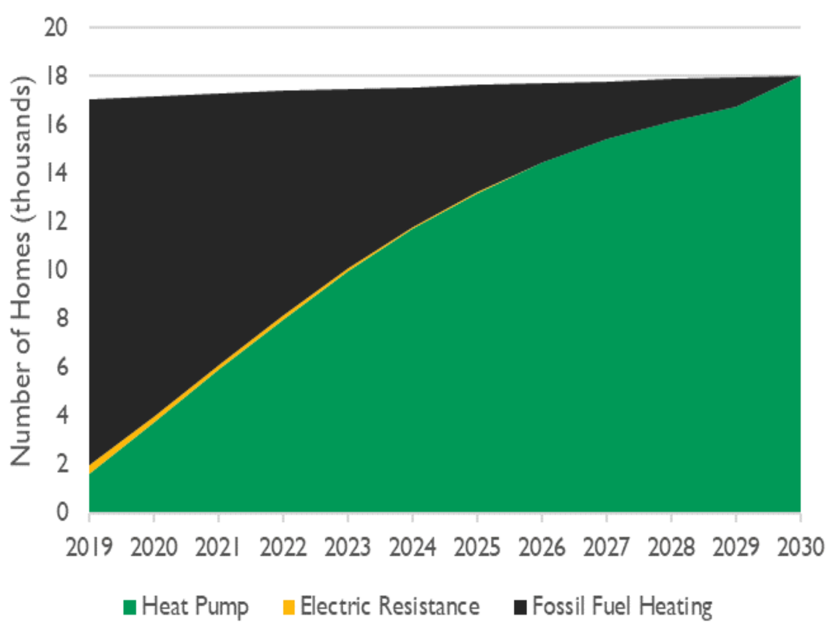
Figure 7-2, shows the peak reduction that can be achieved during periods of high peak probability.

Figure 7-2: Flexible load management of a CCHP during a morning winter peak in early April. The peak reduction is indicated in the highlighted region and the peak savings are represented by the deviation of the blue line from the orange predicted baseline.



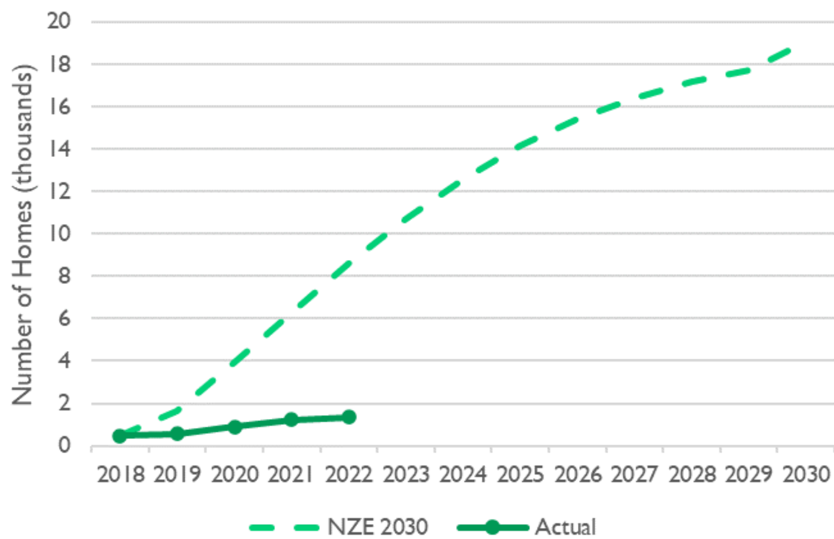
The NZE30 model anticipates that nearly 10,000 residential heat pumps would need to be installed by 2024, and 18,000 by 2030, as shown in Figure 7-3 below.

Figure 7-3 Residential Households with Heat Pumps, NZE Roadmap



Updated data displayed in Figure 7-4 indicate actual heat pump installations are trailing these levels. As of 2022, there were just over 1,300 heat pumps installed in Burlington, well short of the NZE targets. BED believes NZE progress may come in a non-linear fashion, and depending on technology, discounted end-use rate availability, other funding sources such as the recent federal tax credit, and policy changes, the pace of growth may change substantially during the next 10 years; this happened with solar adoption, for example. The NZE goals indicate that nearly all households in the City, including those residing in apartments, condominiums, and single-family structures, would need to install CCHPs.

Figure 7-4: Residential Heat Pump Installations – NZE30 vs Actual



In the commercial building sector, the NZE30 scenario assumed that customers will convert thermal heating and cooling for an increasing amount of floor space to heat pump technology, as shown in

Figure 7-5. These systems would be mostly VRFs, although GSHPs could also be a viable option, even if the existing boiler systems remain in place. In this scenario, heat pumps will serve as the primary heating system and existing heating equipment will back up heat pumps only during extreme cold weather. Also, the NZE30 scenario assumed that a district energy system will be in place and eventually expand to provide heating to substantial portions of the City's large buildings (e.g., UVM Medical Center).

Figure 7-5: Commercial Floor Space Heated with Heat Pumps, NZE Roadmap

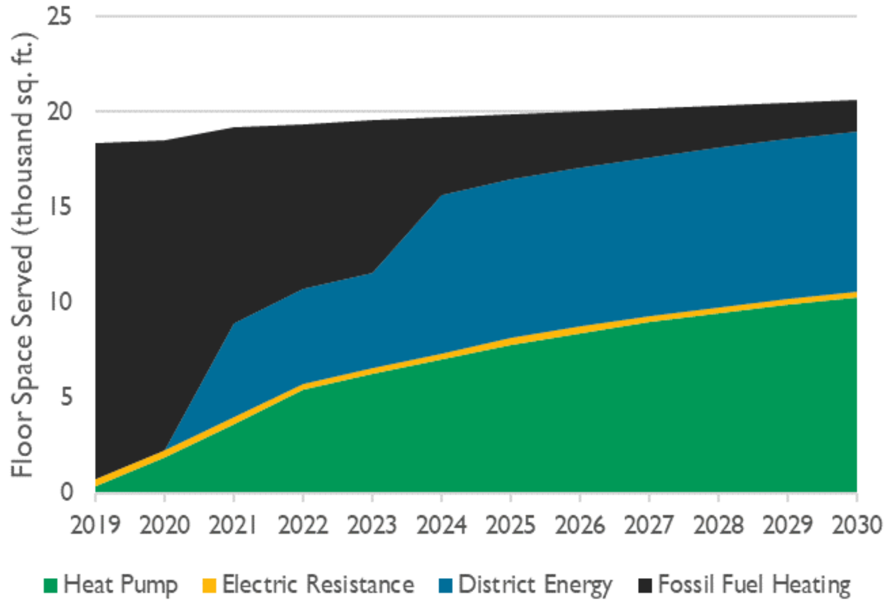
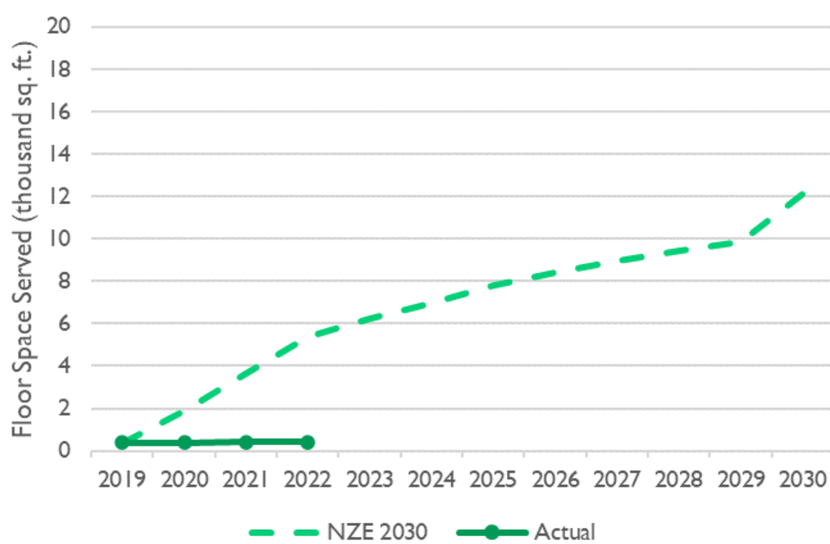


Figure 7-6 below shows that the actual amount of commercial floor space heated by heat pumps is also dramatically behind the Roadmap goal. As of 2022, about 400,000 square feet of commercial space was heated with heat pumps, which is only 8% of what is necessary to be on track for the NZE30 scenario.

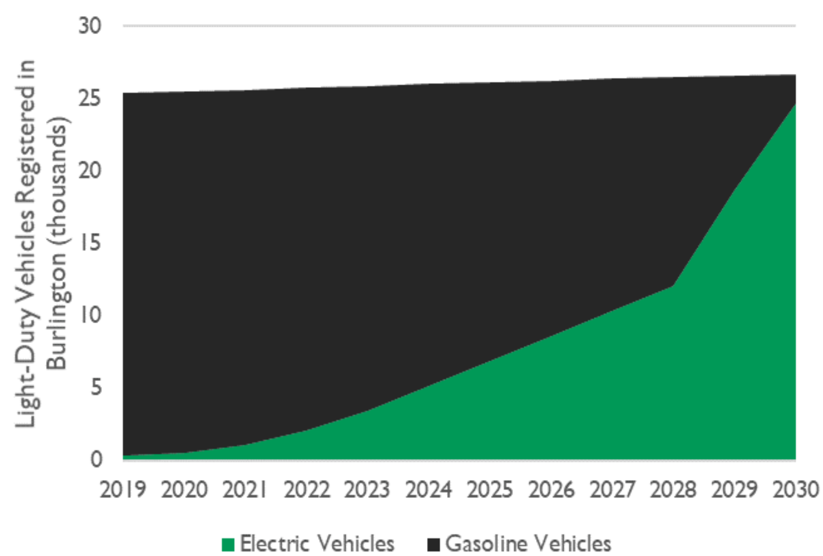
Figure 7-6: Commercial Floor Space heated with heat pumps – NZE30 vs Actual



Pathway 2: Electric Vehicles

The EV pathway also sets aggressive goals for the City. Today, there are approximately 24,000 light-duty vehicles registered in Burlington. Under a BAU case, by 2030 we expect this number to increase modestly as the City's population grows. To achieve the NZE30 goal, however, the Roadmap assumes that almost all of the light-duty vehicles in Burlington are converted to electric vehicles by 2030.[88] As shown in Figure 7-7, the rate of EV adoption needs to be brisk to achieve this goal, particularly after 2022, and would require Burlingtonians to convert from existing internal combustion engines ("ICEs") in significant numbers before the end of their expected useful life (a total estimated lifespan of 12 to 14 years). Under NZE30, the model assumed that nearly 5,000 vehicles registered in Burlington would be electric by 2024, an increase from approximately 400 in 2020.

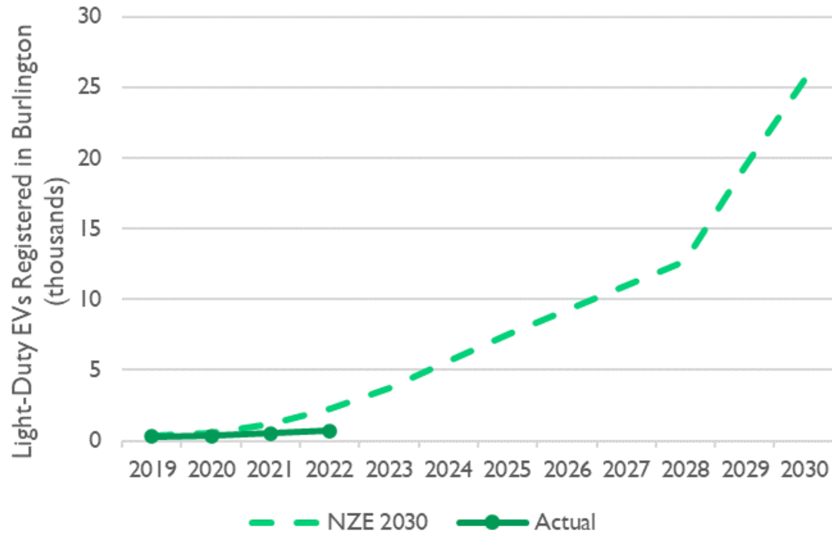
Figure 7-7: Electric Vehicle Adoption Curve, NZE Roadmap



As of 2022, just under 700 EVs were registered in Burlington, which is one-third of the projected path described in the NZE30 scenario.

[88] While other vehicles in the City may also be replaced with vehicles with electrically powered motors such as e-buses and others, this section focuses on light-duty passenger vehicles as they are expected to have the greatest impact on BED's load requirements.

Figure 7-8: Electric Vehicle Adoption Curve, Actual and Projected



Further, the NZE30 path would require nearly 10,000 additional ICE vehicles to be replaced with EVs by 2030. In a typical year, about 1,500 new vehicles are registered in Burlington. BED's existing Tier III incentives are unlikely to result in this level of accelerated adoption alone, but improving EV technology, increased access to used EVs, and improved charging infrastructure are expected to be of material assistance.

Pathway 3: District Energy

The district energy system pathway from the Net Zero Roadmap is the topic of significant current activity and discussion and a decision on whether to proceed is pending. This IRP does not include any analysis, recommendations, or determinations with respect to district energy.

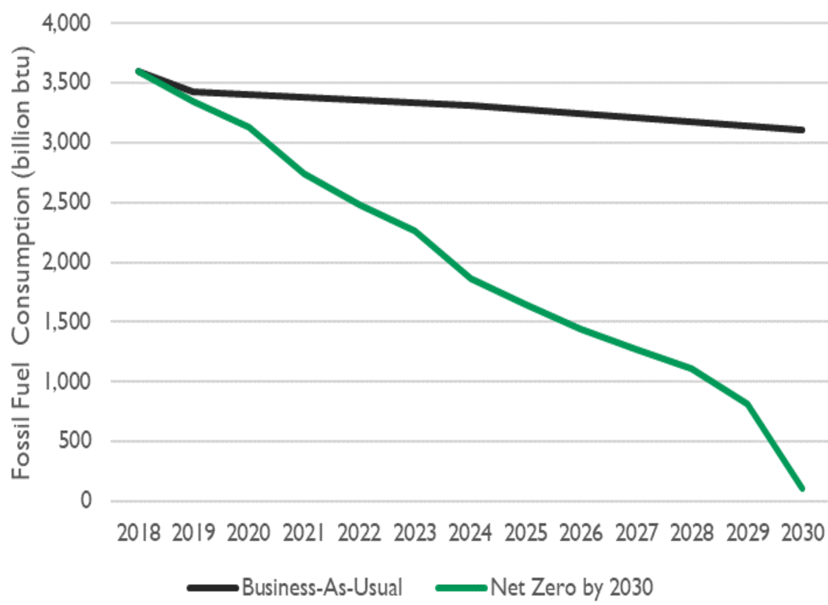
Pathway 4: Alternative Transportation

The last NZE pathway involves alternative transportation modes and related behavioral changes. If achieved, this pathway is expected to result in a 5% reduction in fossil-fuel consumption. The alternative transport pathway assumes that, given increased multi-modal transportation options for commuting to work and other destinations, Burlingtonians will drive a personal vehicle less often. Such options include biking, taking public transit, carpooling, and/or walking. Part of this pathway will be endeavoring to electrify public transportation. BED has been working with GMT to convert more buses from diesel to electric following the deployment of the first two all-electric buses in 2020. This pathway is not expected to have dramatic impacts on BED, unlike the electric buildings, EV, and district energy pathways.

Load and Emission Impacts

Net zero energy does not mean zero energy consumption. Instead, NZE means that as our customers' fossil fuel consumption decrease over time, their energy needs that are not met by increased efficiency are replaced with renewably sourced electricity. Thus, the region below the black line in Figure 7-9, which represents BAU consumption of fossil fuels, is replaced with renewably sourced electricity. The Roadmap model also anticipates that the total amount of energy consumed will decrease to a little more than 3,000 billion BTUs because of increased efficiency in the building and transportation sectors.

Figure 7-9: Fossil Fuel Only Consumption, NZE Roadmap



Under the NZE30 scenario, the increase in electricity consumption will notably impact BED's existing operations and require upgrades to and modification of certain aspects of its operations to ensure continued reliability. Should the City successfully reach NZE using the Roadmap pathways, based on the Roadmap projections the net impact on BED's load requirements would be an increase to roughly 550 GWh from 340 GWh, and peak demand could go from the current 65 MW to 140 MW, as shown in

Figure 7-10 and Figure 7-11. However, the timing of these load impacts is uncertain, largely because many aspects of achieving NZE by 2030 or 2040, such as implementing complementary policy actions, are beyond BED's control. Perhaps more uncertain is the progress, if any, that the rest of New England might make toward NZE, and the impacts on the wholesale electric market and transmission systems that regional decarbonization would cause.

Figure 7-10: Renewable Electricity Sales Projection, NZE Roadmap

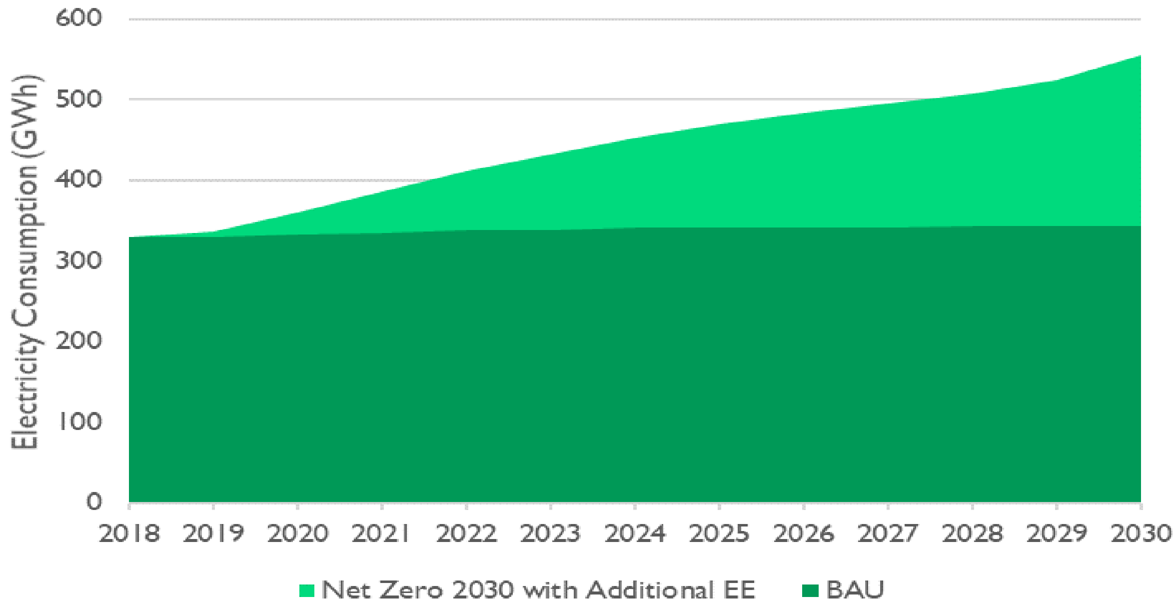
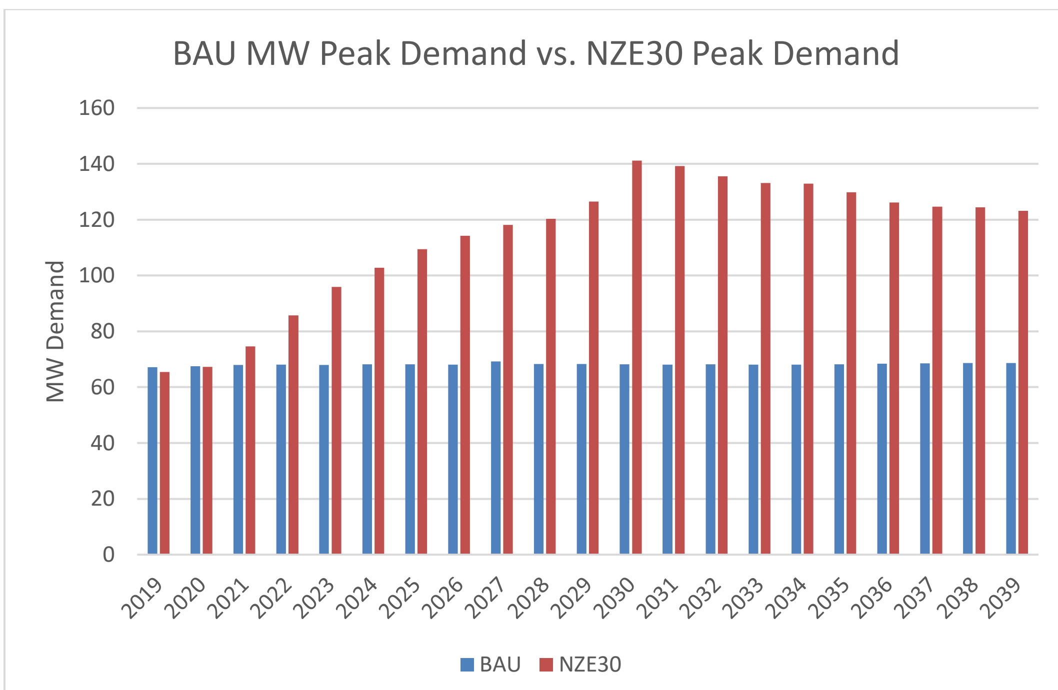


Figure 7-11: Peak Demand Projection, NZE Roadmap



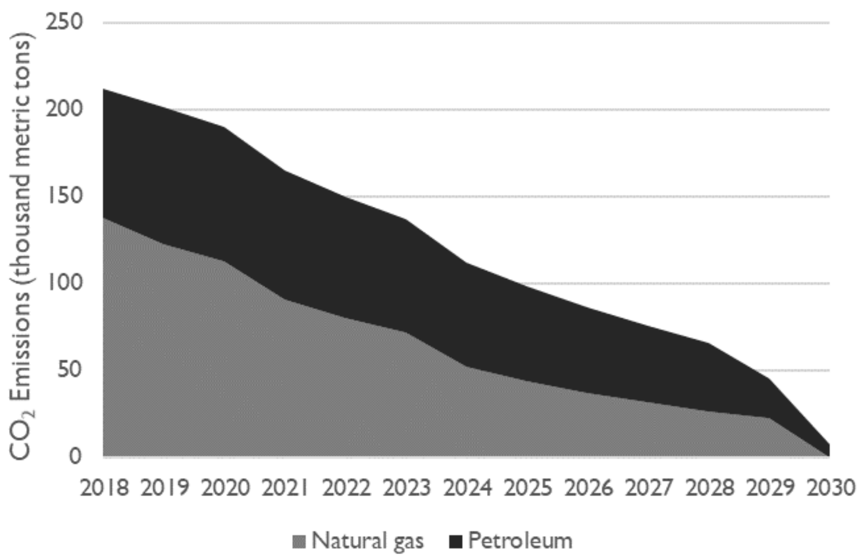
Therefore, BED has elected to review the impacts on its distribution system in stages. In the 2020 IRP, BED modeled peak demand thresholds of 102.8 MW and 120 MW along with corresponding load shapes of the projected decarbonization activities to understand preliminary grid upgrades that could be required to meet the Roadmap's goals. 102.8 MW was selected as a load level that would stress the distribution system past its current capability of serving roughly 80 MW load. The 120 MW level was selected both to represent approximately two-thirds of the increase from 80 to 140 MW, and because above that level the transmission and distribution substations serving BED's load would require material upgrades. The analysis of grid upgrades that would be required to serve the full 140 MW load outlined in the Roadmap has not been completed.

Again,

Figure 7-10 and Figure 7-11 do not represent actual forecasts of specific load occurring by a specific date but rather the load change required to achieve NZE by the specified date (2030 or 2040). The analysis in this chapter does, however, conclude that the cost of distribution upgrades required by load increasing to 102.8 MW, and then to 120MW, should not create significant rate increases, even with necessary distribution system investment. Instead, increases in load may create downward pressure on average costs and rates, as discussed below.

As shown in Figure 7-12, the NZE30 path would reduce GHG emissions by approximately 200,000 tons. Reductions of this magnitude will undoubtedly improve regional air quality and public health.

Figure 7-12: Projected GHG Emissions Reductions, NZE Roadmap



Potential Financial Impacts – 102.8 MW

BED's NZE Roadmap highlights that as load grows with adoption of beneficial electrification measures, so does the potential for system-wide distribution impacts. This cause-and-effect relationship is illustrated in Figure 7-11 above, which shows an estimated peak of 102.8 MW in January 2024 and an estimated peak of 140 MW by January 2030. As peak demand grows, BED will need to make additional investments in its distribution system (ahead of loads actually occurring) to ensure continued reliability.

BED is currently not on the trajectory shown in Figure 7-11, but there remains value in understanding the possible impacts of increased loads on electric rates. With increasing loads, BED will incur additional costs from ISO-NE associated with serving that load. Those charges will not be directly dependent on the resource decisions BED makes due to the ISO-NE market structures. To maintain BED's 100% renewability, an incremental cost associated with acquiring renewable energy (versus simply using wholesale market power) must be included. Finally, the carrying cost, in terms of interest expense associated with financing distribution upgrades and the depreciation expense of the additional distribution assets, will be incurred. BED initially evaluated the costs and revenues associated with serving a load of 102.8 MW in its 2020 IRP and is updating that analysis in this IRP. In a subsequent section BED will rerun this analysis at a winter peak load of 120 MW.

BED will continue to monitor the rate at which its customers adopt beneficial electrification technologies and the corresponding changes in BED loads, to determine at what point upgrades will need to commence. Selecting 102.8 MW as an initial load level for analysis provides BED insight into the subset of investments needed to fully prepare for NZE30 achievement (by setting an analysis level that cannot be served reliably by BED's existing distribution system). The incremental load associated with a peak of 102.8 MW (over that associated with an 80 MW load in the NZE Roadmap) is estimated to be 68 GWh or an approximately 20% increase in load served. Setting an initial NZE evaluation load level allows BED to consider the likely resulting incremental power costs and retail revenues, and whether the combination of these impacts appears to result in upward or downward rate pressures and/or permit favorable rates in support of strategic electrification.

To determine whether distribution system upgrades would be necessary to reliably serve a peak demand load of 102.8 MW, BED analyzed its existing distribution system and explored four contingency scenarios. In each scenario, one of four main distribution substations serving the City was taken offline at a time: the McNeil substation, East Ave #3, East Ave #4, and the Queen City substation. If one of these distribution substations were to be disabled unexpectedly, circuit loading and voltage levels would exceed engineering limits. The effect of such conditions, were they to occur, could cause large areas of unserved load in the event of an outage, as well as poor power quality across much of the distribution system.

By modeling the effects of one substation outage at a time, BED's engineering staff can determine what system upgrades are required to mitigate potential reliability issues and provide reliable service to BED customers at increased load levels.

The upgrades shown in Table 7-1 were identified to address the modeled circuit overload and voltage issues. It is anticipated that these projects would take four to seven years to complete, depending on staffing levels and the availability of capital funds for this purpose in the context of the complete scope of BED's capital budget. Table 7-1 identifies the upgrade, whether the upgrade is needed for base case (all-lines-in) or to meet contingency requirements, the upgrade type, and its estimated cost as of the filing of this IRP.

Table 7-1: Distribution Projects Needed to Support 102 MW

Projects needed for 102 MW Case	**Upgrade/ New/ Completed**	**Project Driver**	**Upgrade Type**	**Estimated Cost**
Extend 2L1 Circuit to pick up load off 1L1 Circuit	New	Base Case	Feeder	$2,291,972
Transfer load between 1L1 to 1L4:				$143,872
Install 556 AL (200 ft) from P3330 (1L1 circuit Staniford Road) to P3111 (1L4 circuit North Avenue). This includes Oakland Terrace, Western Avenue, Woodbury Rd, Woodlawn Rd) and disconnect from 1L1. Disconnect the tap from pole P3351 to P3349.	New	Contingency	Feeder	
Install 1-phase 556 AL (430 ft) from pole P3326 on Woodbury Road (1L1) to pole P3108 on North Avenue (1L4). Disconnect the tap between pole P2823 and P3350.	New	Contingency	Feeder	
Install 1-phase 556 AL (520 ft) from pole P3301 on Woodlawn Road (1L1) to pole P3104 on North Avenue (1L4) and disconnect tap from pole P3244 to P3312.	New	Contingency	Feeder	
Install SCADA controlled switch on P3130 (to become normal open point between 1L1 and 1L4); modeled as Switch# 1000S.	New	Contingency	Switch	
Upgrade 2L5 from 350 Cu to 1000 cu (P2349-330S, 215S-744S, 119S-College Sub)	Upgrade	Contingency	Feeder	$1,787,866
Extend 1L2 to North Avenue & transfer load from 1L4 to 1L2	New	Base Case	Feeder	$4,675,304
Install 4-Way Padmount or Submersible Switch (1002S, 1003S, 1004S, 1005S) at Starr Farm Rd & North Ave	New	Base Case	Switch	$328,639
1L2 extended to Starr Farm Rd 4-way switch (3800' 556 OH, 190' 1000CU UG) and then to Barley Rd (1000' 350CU UG). Load at Barley Rd shifted to 1L2.	New	Base Case	Feeder	$1,565,645

Projects needed for 102 MW Case	Upgrade/ New/ Completed	Project Driver	Upgrade Type	Estimated Cost
1L1 and 1L4 tapped into Starr Farm Rd 4-way switch. 1L1 extended to all Northgate Apartment feeds and load transferred to 1L1 (2290' 556 OH). Xfmr#5000, Xfmr#5052, Xfmr#5059, and Xfmr#5165,5014,5164 moved to 1L1 circuit.	New	Base Case	Feeder	$324,284
Buell St - Convert to 3-Phase from P1348 to P1322	Completed	Base Case	Feeder	-
Heineberg Rd upgrade to 556AL from P3097 to P4193	Completed	Contingency	Feeder	-
Starr Farm Beach - Convert to 2-Phase (BC) from P3665 to P3698. Load Past P3698 moved to Phase C, load before P3698 on Phase B.	Completed	Contingency	Feeder	-
Ethan Allen Pkwy P2942 to P2959 convert to 2-Phase (BA). Load past P2959 move to Phase B. Other loads remain on what is now Phase A (moved from Phase C at P2942)	Completed	Contingency	Feeder	-
Convert Ethan Allen Pkwy northern area (fed underground from pole P2977) to 3-phase and balance the loads. Extend new phase (Phase C) from riser pole P4193 to HH#41. This phase picks up load connected west of HH#41. Load on James Ave, Hope St, and Faith St remain on existing cable, now connected to Phase A at riser pole P4193. Extend new cable from P4193 to HH#44 (Phase B). All load fed out of HH#44 is moved to this new cable and Phase B. The existing cable is transferred to Phase A at riser pole P4193.	New	Contingency	Feeder	$858,945
Phase Load Balancing Steps	Upgrade	Base Case	Feeder	$30,537
Upgrade existing/add new capacitors	Upgrade	Base Case & Contingency	Capacitor	$1,672,503
Replace overloaded transformers	Upgrade	Base Case	Transformer	$7,725,935
Replace Secondaries/Services	Upgrade	Base Case	Feeder	$1,703,934
Create a new 2L8 Circuit	New	Base Case	Feeder	$6,341,554

Projects needed for 102 MW Case	Upgrade/ New/ Completed	Project Driver	Upgrade Type	Estimated Cost
Project Management	New	Base Case	Additional Labor/ Contractor	$883,530

Modeling the results of these upgrades indicates that voltage limitations and thermal loading conditions across the distribution network would remain within appropriate engineering parameters at the 102.8 MW of peak demand, and that consistent, reliable service could be maintained.

Based on the best available information at the time of writing, the total estimated cost of the above infrastructure upgrades for a 102.8 MW system is approximately $30 million (estimates were prepared using 2023 figures for labor, material, and overhead costs). This estimate is based on using existing personnel to complete the work and not hiring external contractors. This represents a material cost increase over the estimate contained in the 2020 IRP, despite the fact that some of the most pressing upgrades that were identified in the 2002 IRP have been completed. This is due to significant inflationary pressures on construction costs since the preparation of the 2020 IRP.

Potential upgrades for loads above 102.8MW will be considered starting from the solutions identified above.

Power Supply Requirements

Maintaining a 100% renewably sourced electric generation portfolio remains the centerpiece of BED's clean energy strategy and is necessary to decarbonize Burlington's thermal and transportation energy sectors. The strategy will require BED to procure more renewable energy to serve the projected 102.8 MW load levels (approximately 69 GWh/20% above the 80 MW load or approximately 133 GWh/40% increase over current needs). While such an increase in energy requirements may be significant for BED, it less significant relative to the total amount of renewable electric energy generated and wheeled throughout the New England system.[89] And, because BED's new energy procurements are so small relative to the total renewable wholesale energy market, we do not expect renewable energy prices to materially increase relative to current prices because of Burlington's NZE efforts.

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[89] According ISO-NE, 11,149 GWh of renewable and 8,788 GWh of hydro was generated in 2019. *See;* https://www.iso-ne.com/about/key-stats/resource-mix/

Since the writing of the 2020 IRP, winter wholesale energy cost forward prices have increased materially. As most of the projected load increase is anticipated to be related to heating, this change will reduce the margin of contribution to fixed cost recovery (or the margin that is available to offer more competitive rates relative to natural gas heating). The incremental costs shown below in Figure 7-13 are based on the anticipated load shape of the projected incremental load that exceeds BED's existing load. The reduction in margin from the 2020 IRP will require some additional work on designing attractive rates for non-fossil-based heating in Burlington.

With respect to capacity, transmission, ancillary, and REC costs, BED similarly assumes that the need for these additional resources is *de minimus* relative to the amount of resource availability throughout the region. Capacity costs for this incremental load are assumed to be minimal as ISO-NE is expected to remain summer peaking for most of the 2023 IRP forecast period. If ISO-NE switches to winter peaking, capacity costs could be increased if heating load coincides with the new ISO-NE peak (though the effect could be moderated by load control). Load control of heating load, however, may not be able to remove all load from a potential peak hour, which would produce some capacity costs incremental to those shown in this section. As a result, currently the wholesale cost of such services is expected to be like current costs, or to follow similar trends in the case of transmission costs for the analysis in this chapter. Combining all expected wholesale energy costs (i.e., energy, capacity, transmission, ancillary, and RECs) will naturally increase BED's cost of service in the aggregate by a material amount.

Preliminary Rate Impact Conclusions

The NZE30 pathway results in both significant forecasted costs and net revenue per MWh for BED. This is illustrated below by the incremental revenues and costs in $/MWh shown in Figure 7-13. Revenues are shown for the residential and small general service rate classes for simplicity, and the rate per kWh from the most recent rate increase request filed with the PUC[90] was used as the starting point for retail rates for 2024. For 2025 and beyond, the starting point rates were increased by the base case change in retail rates from the IRP model, which do not include the T&D carrying costs associated with the upgrades needed to serve loads higher than the base case but do reflect increases needed to cover increasing power costs and other expenses over the IRP horizon.

The incremental load shape deriving the disaggregated costs in this section incorporate interval data for CCHPs not based on the current CCHP pilot data (which is currently in progress). Further, analysis of data from this pilot could alter the incremental cost to serve this end-use

[90] Case # 23-2044-TF filed on June 16, 2023.

technology by adjusting the energy cost-to-serve and incorporating flexible load management in the ability to avoid capacity, transmission, and distribution impacts. Preliminary information indicates that heat pump peak demand may be able to be diversified by 20%-50% for capacity and transmission cost causation.

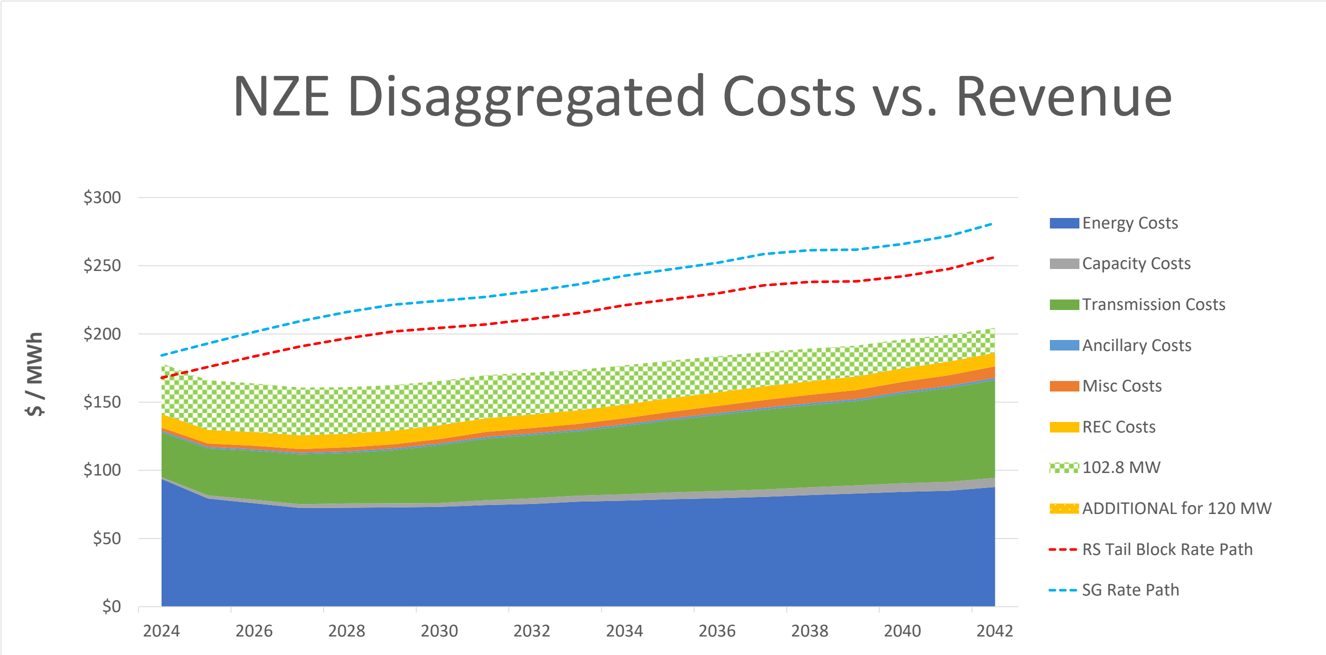
Incremental Costs ($/MWh)

Figure 7-13 illustrates the expected annual costs associated with serving the NZE Roadmap loads at 102.8 MW. To simplify the analysis, since the IRP high case does not reach a 102.8 MW peak, the timing of the loads was immediate for cost purposes. This methodology allows for the consideration in the net impact of the additional load in all years covered by the IRP.

T&D capital costs were converted to per MWh costs through a 25- to 33-year depreciation schedule and a 20-year bond issuance that is consistent with the proposed asset lives and BED's current borrowing practices and then divided by the MWh of additional load associated with those upgrades. Incremental power costs associated with the additional load were derived from the 2023 IRP model by running the model at base case, NZE30 load levels, and calculating the change in costs by power cost area divided by the additional load.

Figure 7-13 indicates that the combined cost in $/MWh to serve the incremental load associated with the 102.8 MW scenario (the carrying cost of the expected distribution upgrades and incremental power and renewability costs) is lower than the projected retail rates in $/MWh revenues under base case IRP rate paths (assuming no discount to rates applicable to the incremental load) for the full 20-year period. This would be true for the initial seven years (residential rate) and 13 years (small general service rate) of the IRP planning horizon at BED's base case projections of wholesale power costs, even if BED had no increases in rates during that period. BED notes that at the 102.8 MW level, the costs of upgrading the distribution system are far less significant than the wholesale power costs to serve the additional load. The conclusion is that excess revenues over the incremental costs to serve provide a contribution to BED's existing fixed costs, which can help to reduce rate pressure, or can provide some discount to rates for incremental loads without adding to rate pressure, or a combination of the two. Being able to offer advantageous rates for the transportation and heating sectors is important both to drive increased adoption of these technologies and to permit operating costs comparable or better than those of the equivalent fossil fuel alternatives.

Figure 7-13: Disaggregated Costs and Revenues at 102.8 MW, $/MWh



Potential Financial Impacts – 120 MW

The analysis shown above was repeated using the same methodology but added to the project list from the 102.8 MW section additional T&D upgrades that would be necessary to serve a winter-peaking 120 MW load, as shown in

Table 7-2.

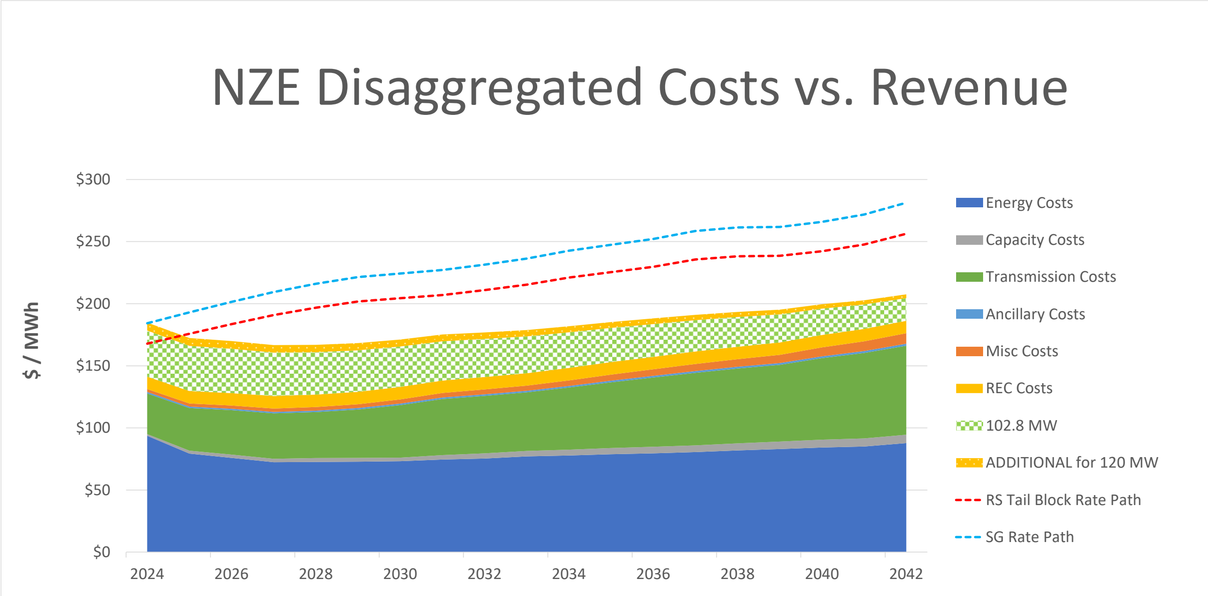
Table 7-2: Additional Distribution Projects Needed to Support 120 MW

ADDITIONAL Projects needed for 120 MW Case	Upgrade/New	Project Driver	Upgrade Type	Estimated Cost
Upgrade existing/add new capacitors	Upgrade/New	Base Case/ Contingency	Capacitors	$295,925
Three Phase Voltage Reg at P3153	New	Base Case	Voltage Reg.	$105,000
134S Switch Automation	Upgrade	Contingency	Switch	$39,715
Apple Tree Point Rd Upgrade (P3369 to TC#94)	Upgrade	Base Case	Feeder	$454,328
Apple Tree Point Rd Upgrade (TC#94 to TC#98)	Upgrade	Base Case	Feeder	$418,654
Brandywine St 2-Phase Conversion	New	Contingency	Feeder	$18,204
347D Upgrade to Automated Switch	Upgrade	Contingency	Switch	$55,550
Van Patten Pkwy Upgrade	Upgrade	Contingency	Feeder	$241,409
McNeil Substation Transformer Upgrade	Upgrade	Base Case	Substation Transformer	$2,507,415

Cost estimates in 2023$ for the above projects are approximately $4.25 million. In terms of cost per MWh of incremental load for serving 120 MW and above, this is materially less than the cost associated with serving 102.8 MW as many of the upgrades to serve 102.8 MW would have already been invested to serve the 102.8 MW load scenario. The projects indicated to serve a minimum of 102.8 MW of demand inherently provide system capacity beyond this limit to some extent (i.e., when constructing a new circuit, the system capacity can accommodate 14 MW of demand when perhaps the study indicated the system was short by only 6 MW, leaving a surplus of 8 MW for growth into the 120 MW scenario). The projects listed for 102.8 MW are also much larger projects in scope bearing greater costs, many being extensions of primary feeder circuits and the construction of a new feeder out of an existing substation. The projects listed in the 120 MW take advantage of the built-out infrastructure of the 102.8 MW case and through only upgrades to existing infrastructure, can expand the system capacity up to 120 MW. It is worth noting that qualitatively this relationship is not anticipated to occur for T&D upgrades to serve loads in excess of 120 MW as above the 120 MW level material work would likely be needed to the interconnections between BED and VELCO/GMP. Accordingly, the value of load control will increase and the load control avoids the need for those upgrades.

Figure 7-14 adds the additional costs to serve loads between 102.8 and 120 MW to Figure 7-13.

Figure 7-14: Disaggregated Costs and Revenues at 120 MW, $/MWh



Conclusions of Impacts at 102.8 and 120 MW

Given the assumptions discussed in this chapter, the 102.8 MW and 120 MW models indicate that the early stages of electrification toward NZE30 would result in significant increases in electric loads that BED would be required to serve. The model further indicates that BED would change from a summer-peaking utility to a winter-peaking utility as more heat pumps are installed (however, BED does not assume a change in ISO-NE to a winter peaking region within the timeframe of this IRP analysis). Due to these projected load increases and shifts in our energy delivery requirements, BED would expect to incur additional distribution infrastructure costs to reliably serve these loads. The cost of upgrades needed to serve the projected load increases is not linear as discussed in more detail above.

Future increases in costs are largely driven by increased energy, capacity, and transmission costs related to the increased load under the 102.8 MW and 120 MW scenarios. The need and associated cost to reinforce sections of the distribution system to reliably serve increased demand are far less significant (especially for loads between 102.8 and 120 MW with a winter peak). As an offset to these increased costs, new heating, cooling, and transportation loads would also result in additional retail revenues. The cost to serve the expected increases in our load requirements from the Roadmap does not include the direct costs of any expanded beneficial electrification programs to meet NZE goals. Likewise, any net Tier III benefit from heating and transportation programs and other Tier III options, if any, is not included in the above analysis.

To implement NZE, at whatever its final deployment rate ends up being, material investments in beneficial electrification programs, system improvements, and supporting rates and policies will be needed and electric consumption will increase dramatically. BED will need to act to limit peak load impacts wherever possible, while also working with customers to increase the overall energy efficiency of their buildings and ground transportation needs. BED will also need to anticipate when increases in demand for power will occur and have in place a distribution network capable of reliably supporting that demand when it occurs. Peaks have been moving to evening hours with few exceptions due to the current levels of solar deployment in the region so additional BTM solar is not anticipated to reduce the impacts of electrification (winter peaks tended to be evening historically). Renewable power will need to be secured in advance of these events, although the existing wholesale market structure makes the timing of contracting for additional renewable resources less critical than that of the needed distribution system upgrades.

BED believes that the primary impacts of the early stages of the Roadmap are:

1. Changes in load level and load shape
2. Increased distribution investments to serve increasing loads
3. Increased costs related to wholesale power costs, renewability and transmission
4. Increased retail revenues associated with the new load

BED has not assumed:

1. Material increases in capital costs associated with load control. Any incremental BED costs associated with load control will need to be considered when rates for load-controlled service are established.
2. Material increases in O&M costs (distribution maintenance, customer service, etc.). To the extent that some of the distribution upgrades represent early replacement of existing infrastructure, some O&M costs may be reduced slightly.
3. Direct costs (such as incentives) associated with BED's existing Tier III plans.

BED has performed this preliminary economic impact of the 102.8 MW loads using updated T&D project cost estimates (converted to annual carrying costs) and using the base case IRP assumptions for wholesale power costs and transmission. For the purposes of this evaluation, BED assumes that the 102.8 MW load level would occur in 2024 and load will grow only slowly thereafter. The analysis is informative and allows for a comparison of the base case rate path to the rate path of the 102.8 MW Scenario with the load shapes assumed in the Roadmap.

BED's analysis shows not only that the loads associated with electrification, the costs of associated distribution infrastructure, and the power and transmission costs related to those loads, can be served without increasing rates, but also that serving these loads will reduce rate pressure by providing additional contributions to existing fixed costs and opportunities for flexible load management, especially for heating loads (the base case forecast assumed significant load control of EVs but not heat pumps), provided that:

- The assumptions are reasonable and
- Electric rates are not materially discounted for CCHP loads without generating additional savings in the costs assumed.

These conclusions are consistent with those contained in the 2020 IRP, although the margin of contribution between the projected rate path and the costs to serve each MWh of load has been reduced due to changing power cost levels and timing and increased construction costs associated with capital upgrades. Accordingly, any proposed special rates offered for EVs and especially for heating loads will need to be monitored if currently available and if new rates, carefully designed in consideration of the above analysis.

This analysis serves as BED's current basis for modeling the effects of NZE actions.

Impacts of More Granular Renewability

BED is considering the impact of moving to a more granular renewability requirement. The current RES requires that utilities demonstrate renewability on an annual average basis. Annual energy sales must be met with the required amounts of renewable energy delivered in the same year. Differences between load and renewable energy in each hour of that year do not impact the ability to meet the RES, although it is important to note that such variances may result in economic impact to deliveries of energy during low load times in New England. An hourly renewability requirement would be expected to cause a material increase in the need for utility scale storage, and if applied to REC requirements could create significant additional REC trading demands.

Nevertheless, if the New England grid moves toward 100% renewability in some manner, balancing load and renewable resources—either by moving load to align with resources through active load control or resources to meet load using some form of storage—will be ever more important.

BED is researching the implications of 100% hourly renewability through a pilot program contract with Prosumer Grid, a company that participated in the 2023 DeltaClimeVT cohort. Prosumer Grid is evaluating the amount of storage that, when coupled with the probable amount of active load control available and BED's existing and projected resources, will result in a match of hourly loads and resources for the IRP horizon. It is likely that the impact of 100%

hourly renewability (versus say 99%) will be cost-prohibitive, but the evaluation will be useful in determining the relationship between additional storage requirements (and cost) and increasing hourly renewability.

ProsumerGrid is also evaluating how much storage capability (MW and MWh), combined with solar and wind energy, can produce baseload-equivalent winter energy in recognition of the existing system constraints and reliability concerns in New England.

Impacts of Forgoing REC Arbitrage

REC arbitrage exposes BED to some price and rate risk. To date, the REC arbitrage values have resulted in a significant lessening of rate increase pressures for BED customers. While not actually a complicated calculation (and probably a calculation that may not require IRP modelling to answer the question), BED felt that a discussion of the potential economic impact on BED of forgoing REC arbitrage was appropriate in this IRP.

As modeled, for any case/scenario, the impact of forgoing REC arbitrage is a loss of revenue, used to offset operating costs, equal to the difference between the sale price of certain RECs and the cost to replace those RECs. Like evaluating hourly renewability, at sufficiently high regional renewability requirements, REC arbitrage becomes meaningless. Table 7-3 below summarizes the economic impact of forgoing REC arbitrage under three indicative scenarios.

Table 7-3: Net Present Value of REC Arbitrage

	20-year NPV
Selling RECs	$99,638,057
Buying RECs	$26,900,693
Net	$72,737,364

Rate-Related Activities

Introduction

BED is developing several new rate design initiatives with the goal of encouraging strategic electrification that avoids coincident peak demand. These initiatives are partially funded by a Vermont Department of Public Service grant[91] and include a Level 1 charging program, development of a heat pump rate, and a commercial demand response program. All three of

[91] https://publicservice.vermont.gov/regulated-utilities/electric/rate-design-initiative, Accessed September 2023

these new rate initiatives aim to send price signals to customers that encourage strategic electrification, which is necessary for achieving BED's goal of reaching NZE.

Electric Vehicle Rate Options

BED aims to expand the current EV charging rate by adding a Level 1 charging option for customers who do not have a Level 2 smart charger. This option would increase availability of EV charging and encourage charging that limits coincident peak demand.

When left uncontrolled, EV charging increases transmission and capacity peaks and costs. This is especially true with Level 2 charging. Currently, BED has a residential EV charging rate that allows residential customers to charge for around \$0.09/kWh, the equivalent of paying \$0.70 per gallon of gasoline. This rate has been successful in shifting EV charging to off-peak times and avoiding additional capacity and transmission charges. By passing these savings on to the customer, BED encourages EV adoption in its service territory and reduces costs for all. Offering a Level 1 charging option would allow more customers to access the rate.

Efficient Electric Thermal Rate

BED is in the process of establishing a CCHP rate to encourage electrification in the heating and cooling sector. A heat pump end-use rate could reduce the cost of electric heating vis-a-vis non-renewable natural gas (heating with a heat pump is already more cost-effective than heating with renewable natural gas). Development of a rate specific to heat pumps should also help mitigate capacity, transmission, and distribution peaks that could occur because of added load in the heating sector.

The new heat pump rate would have both similarities and differences to the current EV rate. Both rates aim to reduce coincident peak demand incurred from electrification and added load, but there are key differences between the heat pump rate and the EV rate. A heat pump has significantly less load control capability than an EV, as it cannot be fully curtailed for long periods of time, especially during cold weather periods, as an EV charger can. In the case of a dual fuel rate, where the customer has a backup heating system, heat pump controls would need to be integrated with the existing heating system to avoid having both heating sources running at the same time and thus increasing customer costs. Under a hypothetical rate, heat pumps would also need additional load control and metering devices installed in the indoor units as those capabilities are generally not built into the heat pump. Finally, heating with electricity, especially with low-performance heat pumps with coefficients of performance less than 2.50, is more expensive than heating with non-renewable natural gas. The economics are quite different for fueling an EV as even the retail electric rates are typically less expensive than gasoline.

When performing research in preparation for the development of this rate, it was determined that electric heating rates typically fall into four categories: Whole-Home Time-of-Use (TOU), Separately Metered TOU, Device-Controlled, and Dual Fuel.

Table 4.b: Heat Pump Rate Options

Whole-Home TOU	Customers with an efficient electric heat source qualify for a TOU rate that gives them a discount on off-peak energy used in their home
Separate Metering TOU	Customers receive a discount on off-peak energy used by their efficient electric heat source
Device-Controlled	Utility adjusts the heat pump set points during peak times and the customer receives a credit for participating
Dual Fuel	During peak times, the utility curtails the customer's heat pump and a backup heat source is used instead

Many utilities across the country have an electric heating or heat pump rate that is structured like one of these four options, but the device-controlled and dual-fuel rates are less common. Utilities currently deploying device-controlled and dual-fuel options include Otter Tail Power Company, Northwestern Rural Electric Co-op, Connexus Energy, and Minnesota Power. BED spoke with representatives from Northwestern Rural Electric Co-op and Otter Tail Power Company to gain insight into their programs and inform the process of designing something similar in Burlington.

The heat pump rate options that best align with BED's goals are the device-controlled and dual fuel options. BED is hoping to design a rate that offers both options to customers. With the device-controlled option for heat pumps, BED will be able to adjust the heat pump set points based on market and load information. With the dual fuel option, BED will curtail the heat pump during load control events and a backup heat source will be triggered to heat the home instead for the duration of the curtailment.

Commercial Demand Response/Flexible Load Management

Flexible Load Management (FLM) is a method for improving the stability and efficiency of the electric utility grid and helps to reduce its operating costs. When there is surplus generation—most often from renewable sources on particularly sunny or windy days, or if the demand for electricity is particularly high, such as on an extremely hot or cold day—the utility will call an "FLM event." An FLM event can be thought of as a schedule that has a signal to follow for specified hours of the day. These signals correspond to a variety of different actions that can be taken with HVAC equipment and other flexible loads behind the customer's meter to either increment or decrement electrical usage.

The most obvious benefit of FLM is to reduce the possibility brownouts or rolling blackouts during peak periods when demand would otherwise outstrip supply. But it also provides long-term benefits by moderating grid operation away from extremes, integrating more renewable generation, and reducing the need to build and operate the expensive and polluting "peaker plants" that are otherwise required to adequately provision the grid. By participating in FLM, facilities play a part in achieving these goals of operating a more cost effective, cleaner, and reliable electric grid.

Participants receive notifications in advance of an FLM event and have the option to opt-in automatically or manually by default. The facility's Building Management System (BMS) is securely integrated with the FLM server and is subscribed to FLM events. This means that participation is fully automated, and the customer does not need to make any manual adjustments in their BMS to participate. If a customer chooses to manually opt-in for FLM events, simply logging into the FLM dashboard and clicking on the opt-in option will enable participation; no further action is required once they are opted in.

FLM works by modulating the electricity use of many buildings in real time across the utility service area. The FLM signal or "Flex Signal" is represented by an integer value from 0 to 10. Normal operation with no FLM event present is represented by a signal value of 5. When there is excess power on the grid or a high demand is anticipated later in the day, the utility will trigger a "load build" event. This means the FLM signal value will be in the range of 4 to 0, with lower numbers representing a more intense effort to build load. Conversely, when expected demand is high the utility will trigger a "shed event" with an FLM signal in the range of 6 to 10, with higher numbers representing a more intense effort to shed load. This pattern shifts consumption from a period of high demand to a period of low demand, using the building as a thermal "battery" to store energy.

During an FLM event, HVAC system parameters are changed automatically by the BMS to increase consumption during a build event or reduce consumption during a shed event. On cold days, this means increasing heating to build load and reducing heating to shed load. On hot days, the inverse will occur, where load is built by increasing cooling and is shed by reducing cooling. On moderate or mild days, the decision whether to manipulate heating or cooling is made based on anticipated conditions later in the day. So, for example, a morning build event might increase heating to help warm up the building, while a mid-day build event would increase cooling ahead of the afternoon warmth. At the end of a build and shed event, FLM is not stopped instantaneously. Instead, the FLM signal will ramp up or down over a period (typically 15-30 minutes) to avoid creating demand spikes or "rebound." The method by which heating or cooling is modulated will depend on the building HVAC systems and control system capabilities. In the ideal case, all demand modulation can be accomplished by raising or lowering the room temperature setpoints (i.e., thermostat setting) across the building. In this case, a load build would be accomplished by raising the heating setpoint or lowering the cooling setpoint, whereas a load shed would be accomplished by lowering the heating setpoint or raising the cooling setpoint. For some buildings, additional controls such as directly limited chiller operation may be used. As the purpose of the exercise is to control electrical demand, modulating heating may not be worthwhile in buildings that use natural gas or oil for heat, especially if there is limited pump load. Conversely, a building heating with electricity, either by direct resistance or a heat pump, can take full advantage heating modulation during an FLM event. In all cases, the owner or operator has complete control. They can choose which rooms, areas, or equipment to enroll in FLM; during an event and choose to except specific zones or systems so that the FLM signal does not affect them.

During BED's pilot program, load building events were only called at BED's building and not for other commercial customers to mitigate potential of setting a higher monthly billing demand for participating customers. It is BED's objective to use the pilot to develop an FLM rate that provides compensation to customers in order to pass on grid savings.

8. Planning Priorities and Action Steps

Based on its Strategic Plan (see Appendices) and the preceding analyses, BED has prioritized the following actions for the next three years. At this time, it appears that none of the contemplated actions would require BED to file a Section 248 permit before the next IRP is scheduled to be filed.

Distribution/Operations

In line with our base case load projections, the Engineering and Operations group's priorities will continue to focus on normal capital replacement and improvement activities in support of system reliability and efficiency (i.e., the base case assumes that energy load is not anticipated to exceed 80 MW). Currently, we anticipate that, should load begin to increase from customer adoption of beneficial electrification measures in larger than expected numbers, BED would need between four and seven years to implement the identified distribution upgrades necessary to serve a peak load of 102.8 MW. Please refer to the NZE chapter for more details on the analysis and projects identified. BED may continue to pursue some of the early-stage upgrades required to serve higher loads but is not expecting to incur the level of costs shown in Chapter 7 without warning.

BED will monitor changes in peak load levels and load shapes to determine how strategic electrification is increasing BED's loads net of other load impacts. If actual load growth begins to accelerate faster than our base case assumptions, the Operations team could begin to implement a series of distribution upgrades discussed in greater detail in the NZE chapter.

BED will also implement a new Advanced Distribution Management System (ADMS), which will consist of upgrades to the Supervisory Control and Data Acquisition (SCADA) system, a new Distribution Management System (DMS) and Outage Management System (OMS). These new systems will help with managing a more complex power grid, strengthening reliability, and streamlining outage restoration.

Generation

Over the near-term, BED's Generation team will be focused on maintaining or improving the reliability of existing generating assets through its maintenance programs. Additionally, funding has been budgeted to convert the Burlington GT to biodiesel operations. BED will pursue converting the GT to run on biodiesel fuel in stages with testing at each stage to make sure the unit can accept increasing amounts of biodiesel. The GT is a fairly old unit and was not designed for biodiesel, and there is limited experience to draw on, but BED is hopeful that biodiesel will provide viable. Ultimately B100 is the target fuel if the unit's capabilities permit it. Presuming a successful conversion all the way to B100, it is possible there might be a slight reduction in the GT's maximum generating capacity, but this is not expected to be significant nor to have a material impact on BED's net capacity position discussed in Chapter 2.

Concurrently with ensuring the reliability/availability of its existing generating fleet, BED is seeking opportunities to improve the efficiency of our resources and provide additional value streams. As in past IRPs, the McNeil Generating Station continues to be a key component of our energy portfolio.

Beginning in July 2022, BED made modifications to its wood purchasing policy to better account for the underlying cost components of the wood. The new model disaggregates the price the McNeil owners pay suppliers for wood into a wood and a fuel/transportation component and recognizes transportation distances with a zone structure. Incentives may be offered when increased deliveries are needed in response to market conditions as well. BED will continue to monitor this policy closely and adjust as necessary to make sure it is functioning as intended for both BED and its suppliers.

BED currently limits itself to owning generation assets inside the City of Burlington, and it is unlikely that any significant owned generating assets will be developed in the period covered by this IRP. The potential exists for storage in Burlington, but it does not appear that ownership provides material economic benefit even after the passage of the 2023 Inflation Reduction Act legislation that permits public entities to realize tax credits like those available to private entities in past years. If such an opportunity did present itself, BED would rely on the tools and decision processes developed for this IRP to evaluate the potential impact of those resources.

This IRP includes an attachment with an updated independent study of the impact of McNeil's operation on the Vermont economy as required by the MOU and Order in BED's 2020 IRP.

Power Supply & Planning

As noted in the Generation and Supply Chapter, BED owns or has contracted energy supplies in excess of our customer needs until 2025 and to cover BED's RES obligations through 2035, unless load levels unexpectedly accelerate due to NZE activities.

Modifications or extensions of existing renewable contracts are likely in the next year and discussions have already begun with those counterparties. One or more of the contracts that will expire and need to be replaced will likely be written for a reduced volume of power to try to avoid the significant impacts of a long winter position caused by changes in BED load levels and projections during and after COVID.

A possibility does exist, largely due to somewhat reduced storage costs, to engage in a PPA for storage capability in the next three years and BED has received proposals for such an asset. BED does not currently anticipate owning such a device at this point as the PPA prices being offered appear to be cheaper than ownership even with the recent tax credit changes. In either case, if BED does decide to pursue a PPA for such an asset, or if the economics of ownership versus PPA should change, BED would rely on the economic analyses and decision-making framework described in this IRP to evaluate the proposals.

BED will continue to engage in legislative or regulatory proceedings to modify Vermont's RES and will seek to maintain both its eligibility for the 30 V.S.A. § 8005(b)(2) alternative compliance provision for RES Tier 2 and for the 30 V.S.A. § 8005a(k)(2)(B) Standard Offer exemption, (provided the renewability tests continue to be met) and its ability to sell and replace RECs not specifically required by the Vermont RES to limit rate pressure. Most important, BED would seek to ensure that past renewable decisions continue to be honored and reflected in any changes to the RES.

Energy Services

BED's Energy Services staff remains focused on delivering comprehensive energy solutions aimed at reducing the consumption of all fuel types in the City. Consistent with 30 V.S.A. § 209(d) and 8005a(3), Energy Services' main priority is to continue providing customers with technical assistance with their energy-related needs and incentives for making energy efficient choices. This responsibility extends beyond traditional electric efficiency services and includes technical assistance relative to beneficial electrification measures. As in the past, Energy Services staff will help customers address their building weatherization/thermal needs by coordinating services with VGS, where appropriate, or providing incentives through our weatherization partners to customers heating their buildings with nonregulated fuels or electric resistance technologies.

Since Energy Services is the primary point of contact for customers seeking answers to their energy questions, they also provide critical input into program designs and implementation strategies. Similarly, Energy Services staff will continue to seek out new opportunities for additional Tier 3 custom measures and other efficiency programs that increase customer benefits and support the City's NZE transformation.

While the level of energy efficiency investment is determined through the DRP process, BED seeks to align deployment of efficiency measures with key avoided costs and externality assumptions between the DRP and IRP processes for consistency of decisions over time. The passage of Act 44 of the 2022 offers additional flexibility both in the continuation of use of EEU funds in support of Tier 3 activities (effectively extending Act 151 of the 2023 legislative session) and permitting broader use of TEPF funds as well. Energy Services will be filing a revised DRP that proposes how this additional flexibility will be used shortly after the filing of this IRP.

BED intends to continue to develop new Tier 3 programs and will continue to prioritize meeting its RES Tier 3 requirements with end-use electrification programs to the greatest extent possible. BED is working through its Sustainability/Equity team to design new programs, and redesign current offerings, to ensure all programs are equitable and accessible to all customers.

Customer Care/Engagement

The work and expertise required of BED's Customer Care team will continue to increase with movement toward attaining our NZE goals through strategic electrification. Therefore, achieving the twin goals of maintaining the required metrics under BED's SQRP and simultaneously providing exceptional customer care will be a continuing challenge. BED is fortunate to have a top-notch Customer Care team capable of absorbing additional challenges and we are unique among Vermont's distribution utilities in that our Energy Services team partners with the Customer Care team to serve our customers. Nevertheless, the first contact most customers have with BED generally is with a member of the Customer Care team and, accordingly, maintaining BED's excellence in responding to customers during these exciting times of change and progress in the utility industry will be a key focus.

Finance/Rates

BED will continue to closely monitor its financial performance inclusive of operational and capital budgets, credit rating factors, and other key financial indicators over the next three years and will focus on improving its long-range financial forecasts to inform planning and decision-making. Further, the team will be focused on process documentation, process improvement, and creating efficiencies as part of a planned replacement of our Financial Information System.

Beginning in 2021, and subsequently in 2022 and 2023, BED has begun seeking modest rate increases to allow revenues to keep pace with increasing costs. This is a material change from the 2020 IRP because as of 2020, rates had not been increased since 2009. BED expects the most recent trend of rate increases to continue, at least in the short term, and uses a five-year budget forecast to project what increases may be required to allow critical financial metrics to be maintained.

Rate design improvements remain likely in the next three years. All of the rate changes discussed below will require local approvals before they can be filed, and State approvals before they can take effect.

Potential improvements in rate design being explored currently are:

1. A conversion of BED's pilot Energy Assistance Program to a permanent rate to continue providing economic relief to our customers with the greatest need.

2. A possible CCHP “end use” rate to create some load control capability for this key technology and potentially improve the economics of CCHPs in comparison with natural gas–fired heating systems. While implementing this rate presents some challenges as noted in the NZE chapter, BED believes that bridging the operational cost gap between fossil fuels and electric heating is critical to the success of decarbonization efforts.

Information Systems

A primary focus of BED’s Information Systems department over the next two to three years is the continued conversion of core utility and business systems to more modern platforms under BED’s “IT Forward” project. This project is replacing several of BED’s core business systems as well as providing new functionality. In 2023 BED replaced its meter data management system (MDMS) and its customer portal. Phase 2 of the MDMS project, which adds grid analytics capabilities, is underway. BED recently concluded an RFP process to upgrade its SCADA system and obtain new capabilities for outage management and advanced distribution management; this project is in the contract negotiation phase with a targeted implementation start date of early 2024. BED is currently preparing to issue an RFP for a new customer information and billing system. These projects will require a material time commitment from many divisions of BED.

Other near-term priorities include continued cyber threat monitoring and enhancing BED’s cybersecurity capabilities, completing upgrades to our AMI/smart grid infrastructure, and developing an integrated information and operational technology plan that supports BED’s strategic objectives.

Sustainability and Workforce Development

The Sustainability and Workforce Development team will continue to offer support and guidance to BED’s various departments, including the Customer Care, Communications and Energy Services teams to design new programs, identify new opportunities, and to ensure that BED’s efforts are equitable and accessible to all customers. This includes translating BED documents and information into Burlington’s most prevalent languages, expanding outreach methodology to include video and additional social media platforms, and collaborating with Burlington’s community-based organizations on outreach and engagement to Burlington’s diverse communities. This also includes working with several partner organizations dedicated to workforce training and development to help BED diversify and grow its own staff, and to help grow the availability of technical specialists required to meet BED’s NZE goals. The Sustainability and Workforce Development team is also engaged with policy design and development that support BED’s NZE goals and further strategic electrification efforts.

Safety, Risk Management and Facilities

BED's Center for Safety strives daily to provide high quality support and services to our customers and co-workers. Maintaining a safe working environment is always the continuing priority. Managing risk exposure through insurance and other loss control/mitigation techniques is our commitment.

While fulfilling the group's core responsibilities, the Safety, Risk Management and Facilities group also provides support for some major IRP related goals/projects by:

- Following up the addition of the new all electric bucket truck (the first in Vermont) with participation in electrification programs involving lawn and power equipment, snow removal, fleet vehicles, biodiesel conversions, etc. wherever practical. BED is seeking to add another all-electric line truck to its fleet.

- Providing access to BED facilities for Policy and Planning-led R&D projects to test new technologies to verify their suitability for broader deployments.

- Continued capitalization or support of projects such as radiant flooring, insulating buildings, HVAC improvements, a truck bay air system, etc., towards achieving our NZE goals.

Research/Pilot Efforts

BED is engaged in several opportunities to explore innovative solutions to better serve our customers. BED has established a strong partnership with, DeltaClime[VT], a Vermont business accelerator focusing on clean-technology and the climate economy. BED plans to continue to serve as a host organization by providing access to its facilities for in-person sessions and offer mentorship and pilot opportunities to the cohort of participating companies. BED is exploring capabilities of new devices and systems with a focus on flexible load management to minimize wholesale market and distribution costs as well as distributed generation and planning. Current pilots underway or in development include:

1. BED was recently selected for contract negotiations for a significant federal grant under the Department of Energy's Grid Resiliency and Innovation Partnerships ("GRIP") program for its Building Grid-edge Integration and Aggregation Network of Thermal Storage (Building GIANTS) proposal to create a network of thermal storage resources across residential, commercial, and industrial HVAC using grid-edge devices. This grant is intended to build on work facilitated in this area under a Vermont PSD grant award and is intended to deploy more broadly the load control technologies form the PSD pilot.

2. Engaging with Prosumer Grid to evaluate the changing needs of BED's distribution system and storage requirements as discussed more fully in the NZE chapter, the results of which are planned to be filed as an addendum to this IRP.
3. A pilot project with PlugZen, an electric vehicle charger hardware company that provides a master/satellite unit level 2 charger option that BED hopes will assist multi-family locations with EV charger deployment.
4. A pilot with Vermillion Technologies to demonstrate an inverter designed to integrate solar, wind and storage at a location using the ARC vertical wind turbine, currently installed at the Burlington Airport.

Net Zero Energy

As discussed in the Chapter of the same title, BED remains intently focused on activities that advance the City's NZE vision.

Knowledge to Shape Your Future

Electric | Gas | Water
information collection, analysis and application

2023 Long-Term Energy and Demand Forecast

Burlington Electric Department

Submitted to:

Burlington Electric Department, Vermont

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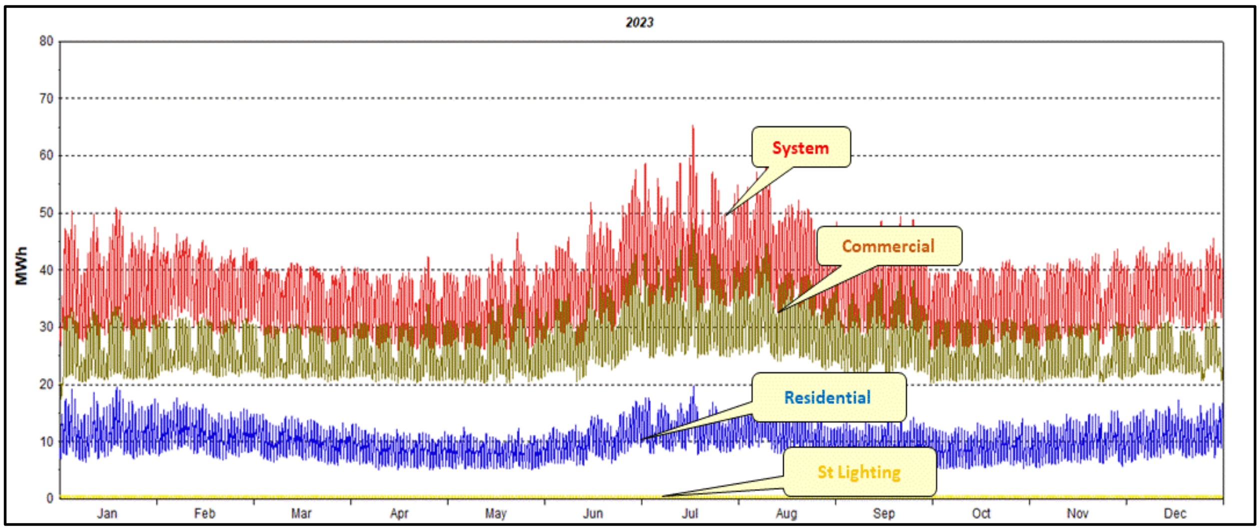
1 OVERVIEW

Itron, Inc. recently completed the long-term energy and demand forecast to support the Burlington Electric Department (BED) 2023 Integrated Resource Plan. The forecast extends through 2042.

BED serves approximately 21,500 customers – 17,500 residential customers and 4,000 commercial customers. As the state's primary commercial and education center, the commercial sector accounts for roughly 71% of BED's sales. Given the large commercial load and associated cooling requirements, BED is a summer peaking utility and continues to be through the forecast period. Figure 1 illustrates the relative impact of customer class loads.

FIGURE 1: BASE YEAR SYSTEM HOURLY LOAD



1.1 SYSTEM FORECAST SUMMARY

Baseline sales forecast which includes residential and commercial sales before adjustments for solar, heat pumps, and electric vehicles are relatively flat over the forecast period; expected improvements in end-use efficiency resulting from end-use stock turnover and BED efficiency programs counters customer and economic growth. Over the long-term it is the expected electrification effort through promotion of cold climate heat pumps, electric vehicles, and electrification of the bus system that drives long-term demand. Table 1 shows the expected long-term energy requirements.

TABLE 1: BED SYSTEM ENERGY FORECAST (BASE CASE)

Year	Baseline	Chg	PV	EV	HP	Adjusted	Chg
2023	327,778		-7,340	485	1,379	322,301	
2024	327,836	0.0%	-7,908	1,496	2,796	324,222	0.6%
2025	327,578	-0.1%	-8,443	2,475	4,259	325,867	0.5%
2026	328,605	0.3%	-8,992	3,437	5,765	328,816	0.9%
2027	328,960	0.1%	-9,524	4,399	7,299	331,134	0.7%
2028	329,640	0.2%	-10,066	5,643	8,876	334,092	0.9%
2029	328,676	-0.3%	-10,551	6,833	10,480	335,438	0.4%
2030	328,172	-0.2%	-11,057	8,024	11,926	337,064	0.5%
2031	327,751	-0.1%	-11,552	9,483	13,216	338,898	0.5%
2032	328,270	0.2%	-12,059	10,943	14,387	341,543	0.8%
2033	327,278	-0.3%	-12,476	12,402	15,439	342,644	0.3%
2034	326,938	-0.1%	-12,891	14,440	16,214	344,701	0.6%
2035	327,008	0.0%	-13,297	16,478	16,789	346,979	0.7%
2036	328,345	0.4%	-13,726	18,516	17,229	350,364	1.0%
2037	328,164	-0.1%	-14,071	21,319	17,551	352,962	0.7%
2038	328,993	0.3%	-14,431	24,123	17,725	356,410	1.0%
2039	329,909	0.3%	-14,777	26,926	17,809	359,869	1.0%
2040	331,357	0.4%	-15,152	30,349	17,862	364,415	1.3%
2041	331,310	0.0%	-15,443	33,771	17,889	367,528	0.9%
2042	332,237	0.3%	-15,759	37,194	17,904	371,573	1.1%
23-42		**0.1%**					**0.8%**

- Baseline is reconstituted for own-use generation and includes efficiency savings impact.

The baseline forecast is adjusted for past residential solar generation use as our objective is to estimate long-term customer energy requirements - not just purchases. Residential average use and commercial sales are modeled on a "reconstituted" basis – actual solar own use is added back to residential billed sales.

The expected growth in solar, electric vehicles, and heat pumps reshape system load over time and in turn impact peak demand. Table 2 and Table 3 show the Base Case summer and winter coincident peak forecasts.

TABLE 2: SUMMER COINCIDENT PEAK DEMAND (MW)

Year	Baseline	Chg	PV	EV	HP	Adjusted	Chg	PeakDt
2023	65.2		-3.8	0.0	0.4	61.9		7/18/23 3:00 PM
2024	65.3	0.2%	-3.9	0.1	0.9	62.4	0.8%	7/23/24 3:00 PM
2025	65.4	0.2%	-4.2	0.2	1.3	62.7	0.5%	7/22/25 3:00 PM
2026	65.7	0.5%	-4.6	0.3	1.8	63.2	0.8%	7/21/26 3:00 PM
2027	65.9	0.3%	-4.8	0.3	2.3	63.6	0.6%	7/20/27 3:00 PM
2028	65.5	-0.6%	-4.5	0.3	2.8	64.2	0.9%	7/18/28 4:00 PM
2029	66.1	0.9%	-5.2	0.5	3.2	64.7	0.8%	7/24/29 3:00 PM
2030	65.6	-0.8%	-4.7	0.5	3.7	65.1	0.6%	7/23/30 4:00 PM
2031	65.7	0.2%	-5.0	0.6	4.2	65.4	0.5%	7/22/31 4:00 PM
2032	66.0	0.5%	-5.3	0.7	4.5	65.8	0.6%	7/20/32 4:00 PM
2033	66.0	0.0%	-5.5	0.7	4.9	66.1	0.5%	7/19/33 4:00 PM
2034	66.1	0.2%	-5.7	0.9	5.1	66.3	0.3%	7/18/34 4:00 PM
2035	66.3	0.3%	-5.7	1.0	5.3	66.9	0.9%	7/24/35 4:00 PM
2036	66.7	0.6%	-5.9	1.1	5.4	67.3	0.6%	7/22/36 4:00 PM
2037	66.9	0.3%	-6.2	1.3	5.5	67.5	0.3%	7/21/37 4:00 PM
2038	67.2	0.4%	-6.4	1.5	5.6	67.9	0.6%	7/20/38 4:00 PM
2039	67.6	0.6%	-6.5	1.6	5.6	68.4	0.7%	7/19/39 4:00 PM
2040	68.1	0.7%	-6.8	1.8	5.6	68.8	0.6%	7/17/40 4:00 PM
2041	68.9	1.2%	-7.6	2.6	5.5	69.5	1.0%	7/23/41 3:00 PM
2042	69.3	0.6%	-7.8	2.9	5.5	69.9	0.6%	7/22/42 3:00 PM
23-42		**0.3%**					**0.6%**	

The summer peak varies between 3:00 and 4:00 in the afternoon largely depending on the load adjustment impacts (i.e., PV, EV, and HP) which in turn is dependent on the technology hourly load shape. While PV growth reduces summer peak demand, expected EV charging (work charging and electric buses) and heat pump cooling add load contributing to a positive net impact at peak. The PV, EV, and HP adjustment doubles the system peak demand growth from 0.3% per year to 0.6% per year.

Table 3 shows the winter peak demand growth.

TABLE 3: WINTER COINCIDENT PEAK DEMAND (MW)

Year	Baseline	Chg	PV	EV	HP	Adjusted	Chg	PeakDt
2023	50.9		0.0	0.0	0.6	51.5		1/18/23 6:00 PM
2024	50.8	-0.2%	0.0	0.1	1.3	52.1	1.2%	1/24/24 6:00 PM
2025	50.7	-0.2%	0.0	0.1	1.9	52.7	1.2%	1/22/25 6:00 PM
2026	50.7	0.0%	0.0	0.2	2.6	53.5	1.5%	1/21/26 6:00 PM
2027	50.7	0.0%	0.0	0.2	3.3	54.1	1.1%	1/20/27 6:00 PM
2028	50.7	0.0%	0.0	0.2	4.0	54.9	1.5%	1/19/28 6:00 PM
2029	50.4	-0.6%	0.0	0.3	4.7	55.4	0.9%	1/24/29 6:00 PM
2030	50.3	-0.2%	0.0	0.3	5.4	56.0	1.1%	1/23/30 6:00 PM
2031	50.1	-0.4%	0.0	0.4	6.0	56.5	0.9%	1/22/31 6:00 PM
2032	50.1	0.0%	0.0	0.5	6.4	56.9	0.7%	1/21/32 6:00 PM
2033	49.8	-0.6%	0.0	0.5	6.9	57.3	0.7%	1/19/33 6:00 PM
2034	49.7	-0.2%	0.0	0.6	7.3	57.6	0.5%	1/18/34 6:00 PM
2035	49.6	-0.2%	0.0	0.7	7.5	57.8	0.3%	1/24/35 6:00 PM
2036	49.6	0.0%	0.0	0.8	7.7	58.1	0.5%	1/23/36 6:00 PM
2037	49.5	-0.2%	0.0	0.9	7.9	58.3	0.3%	1/21/37 6:00 PM
2038	49.5	0.0%	0.0	1.0	8.0	58.5	0.3%	1/20/38 6:00 PM
2039	49.5	0.0%	0.0	1.2	8.0	58.7	0.3%	1/19/39 6:00 PM
2040	49.6	0.2%	0.0	1.3	8.0	58.8	0.2%	1/18/40 6:00 PM
2041	37.2	-25.0%	0.0	14.7	7.6	59.5	1.2%	1/23/41 11:00 PM
2042	37.3	0.3%	0.0	16.2	7.6	61.2	2.9%	1/22/42 11:00 PM
23-42		**-1.4%**					**0.9%**	

Through 2040, the winter demand peaks at 6:00 P.M. The baseline winter peak demand declines 0.2% on average through 2040. The decline is largely the result of improving lighting efficiency (with the largest lighting efficiency gains in the commercial sector), thermal shell and other end-use efficiency gains operating at the time of the peak. In 2041, there is a significant drop in baseline coincident peak as the winter peak demand shifts from 6:00 P.M to 11:00 P.M as a result of reaching high EV charging loads. The adjusted winter peak averages 0.9% compared with adjusted summer peak of 0.6% average long-term growth. The winter peak is largely driven by heat pump adoption through 2040. The EV charging coincident peak is relatively small through 2040. EV charging is based on an incentivized control profile that limits charging until late at night – well past the 5:00 winter peak. After 2040, EV energy requirements coupled with the incentivized charging profile, pushes system winter peak to 11:00 P.M. The 2041 baseline demand at 10:00 drops 25% from the 6:00 p.m. coincident baseline demand in 2040.

The forecast is bound with both higher and lower long-term potential outcomes that are largely based on higher (and lower) heat pump and electric vehicle adoption. Table 4 and Table 5 show the potential range of demand outcomes.

TABLE 4: SUMMER PEAK SCENARIOS (MW)

Year	Low Case	Chg	BaseCase	Chg	High Case	Chg
2023	61.8		61.9		62.1	
2024	62.2	0.6%	62.4	0.8%	62.7	1.0%
2025	62.4	0.3%	62.7	0.5%	63.2	0.8%
2026	62.7	0.5%	63.2	0.8%	63.9	1.1%
2027	63.1	0.6%	63.6	0.6%	64.5	0.9%
2028	63.5	0.6%	64.2	0.9%	65.3	1.2%
2029	64.0	0.8%	64.7	0.8%	66.1	1.2%
2030	64.2	0.3%	65.1	0.6%	66.7	0.9%
2031	64.5	0.5%	65.4	0.5%	67.2	0.7%
2032	64.7	0.3%	65.8	0.6%	67.8	0.9%
2033	64.9	0.3%	66.1	0.5%	68.3	0.7%
2034	65.1	0.3%	66.3	0.3%	68.7	0.6%
2035	65.6	0.8%	66.9	0.9%	69.4	1.0%
2036	66.0	0.6%	67.3	0.6%	69.9	0.7%
2037	66.1	0.2%	67.5	0.3%	70.1	0.3%
2038	66.5	0.6%	67.9	0.6%	70.6	0.7%
2039	66.9	0.6%	68.4	0.7%	71.1	0.7%
2040	67.3	0.6%	68.8	0.6%	71.6	0.7%
2041	67.9	0.9%	69.5	1.0%	72.4	1.1%
2042	68.2	0.4%	69.9	0.6%	72.9	0.7%
23-42		**0.5%**		**0.6%**		**0.8%**

TABLE 5: WINTER PEAK SCENARIOS (MW)

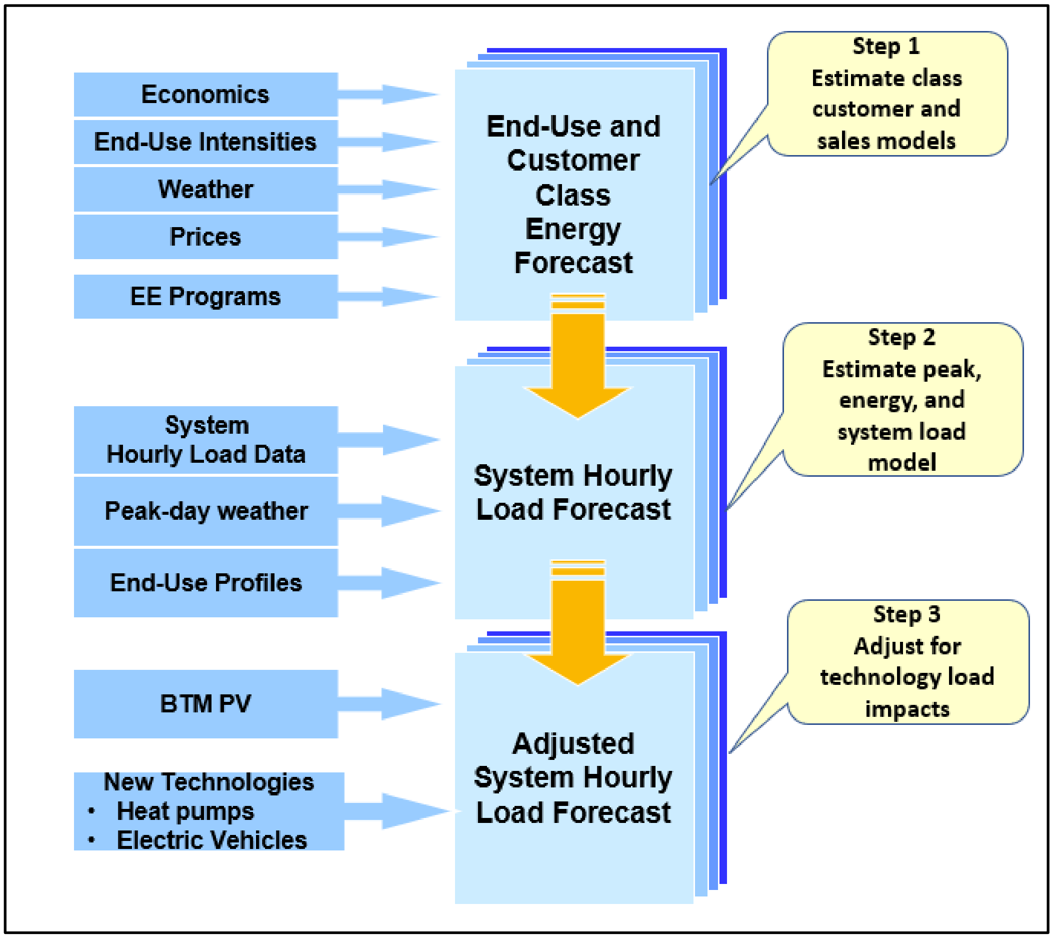
Year	Low Case	Chg	BaseCase	Chg	High Case	Chg
2023	51.4		51.5		52.6	
2024	51.8	0.8%	52.1	1.2%	54.3	3.2%
2025	52.3	1.0%	52.7	1.2%	56.1	3.3%
2026	52.9	1.1%	53.5	1.5%	58.0	3.4%
2027	53.4	0.9%	54.1	1.1%	59.9	3.3%
2028	54.0	1.1%	54.9	1.5%	61.9	3.3%
2029	54.4	0.7%	55.4	0.9%	63.8	3.1%
2030	54.8	0.7%	56.0	1.1%	65.6	2.8%
2031	55.2	0.7%	56.5	0.9%	67.2	2.4%
2032	55.5	0.5%	56.9	0.7%	68.6	2.1%
2033	55.8	0.5%	57.3	0.7%	69.9	1.9%
2034	56.0	0.4%	57.6	0.5%	70.9	1.4%
2035	56.1	0.2%	57.8	0.3%	71.6	1.0%
2036	56.4	0.5%	58.1	0.5%	72.3	1.0%
2037	56.5	0.2%	58.3	0.3%	73.5	1.7%
2038	56.7	0.4%	58.5	0.3%	74.4	1.2%
2039	56.8	0.2%	58.7	0.3%	75.0	0.8%
2040	57.0	0.4%	58.8	0.2%	76.0	1.3%
2041	57.0	0.0%	59.5	1.2%	77.5	2.0%
2042	57.1	0.2%	61.2	2.9%	79.4	2.5%
23-42		**0.6%**		**0.9%**		**2.2%**

In the high case, heat pump and EV adoption (the primary targeted electrification technologies) have a significant impact on demand with system peak switching from summer to winter in 2032. The high case demand growth is also significantly higher, averaging 2.2% winter peak demand growth compared with 0.6% average demand growth in the base case summer peak demand.

2 FORECAST APPROACH

System energy requirements and peak demand forecasts are derived using a “bottom-up” framework that starts with customer class sales forecast that are then used to generate system energy and peak demand forecasts. System peak, energy, and loads are then adjusted for impact of future technologies that reshape system load. Figure 2 illustrates the bottom-up approach.

FIGURE 2: BED LONG-TERM BUILD-UP MODEL



Step 1 is to estimate monthly residential and commercial sales and customer models. The residential forecast is derived as the product of the customer forecast and average use forecast. The commercial sales forecast is derived from a monthly sales model. Estimated models that capture household growth and economic activity, weather conditions, price, end-use intensities. trends, and energy efficiency program impacts. This is referred to as the baseline sales and energy forecast. The structure of the residential average use and commercial sales model allows us to isolate monthly heating, cooling, and non-weather sensitive end-use energy requirements.

In Step 2, heating, cooling, and non-weather sensitive end-use requirements derived from the sales models are combined with peak-day weather conditions to estimate a monthly peak demand model. The outcome is a monthly peak demand forecast that is based on projected customer class-level end-use energy requirements. As part of step 2 we also estimate system hourly load profile based on historical system hourly load (reconstituted for solar generation) that reflects expected weather conditions, day of the week, hours of light, and holidays. The baseline system hourly load forecast is then derived by combining sales/energy requirement forecast, monthly system peak forecast, and system load profile. The 8,760 baseline hourly load forecast is generated through 2043.

Step 3, entails adjusting the baseline system load forecast for the impact of solar, heat pumps, and electric vehicle adoption. These technologies reshape system load over time impacting both the timing and level of system peak demand.

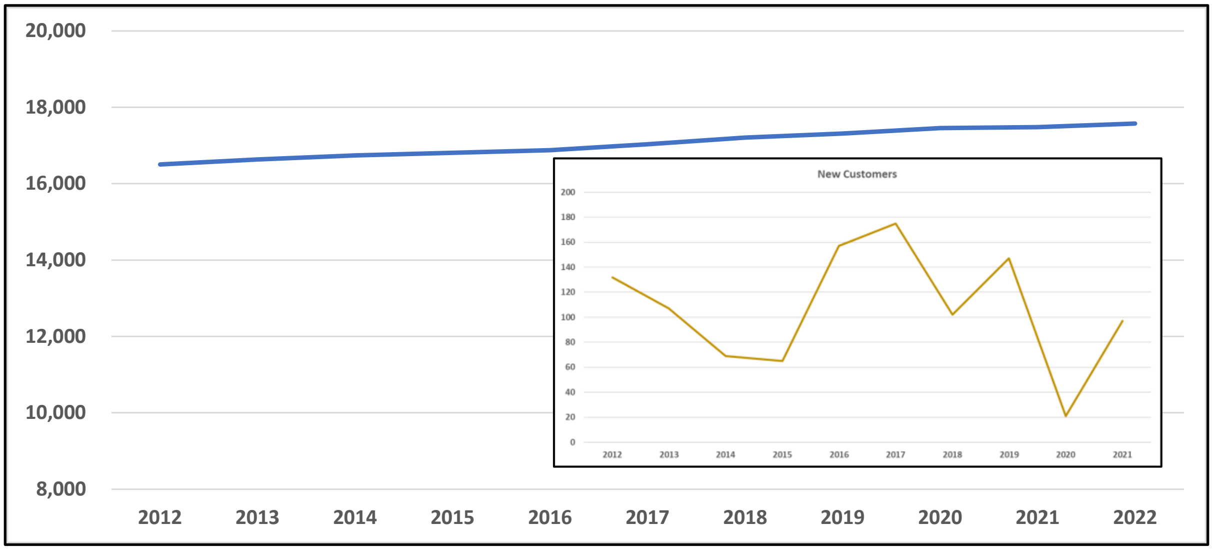
2.1 CLASS SALES FORECAST (STEP 1)

A baseline forecast is developed for the residential, commercial, and street lighting revenue classes. The baseline forecast excludes the impact of additional solar loads, electric vehicles and heat pumps. The forecast is based on historical monthly sales and customer data and underlying factors driving sales growth including number of customers (household growth) household income and household size, end-use saturation and efficiency trends, weather trends, employment growth and business activity as measured by regional output. Forecasts are based on monthly sales (average use for residential class) and customer models estimated using linear regression. Models are estimated over the period January 2012 through October 2022.

2.1.1 Residential Baseline Model

Residential sales account for 30 percent of BED sales with BED serving approximately 17,500 residential customers. Figure 3 shows the customer trend.

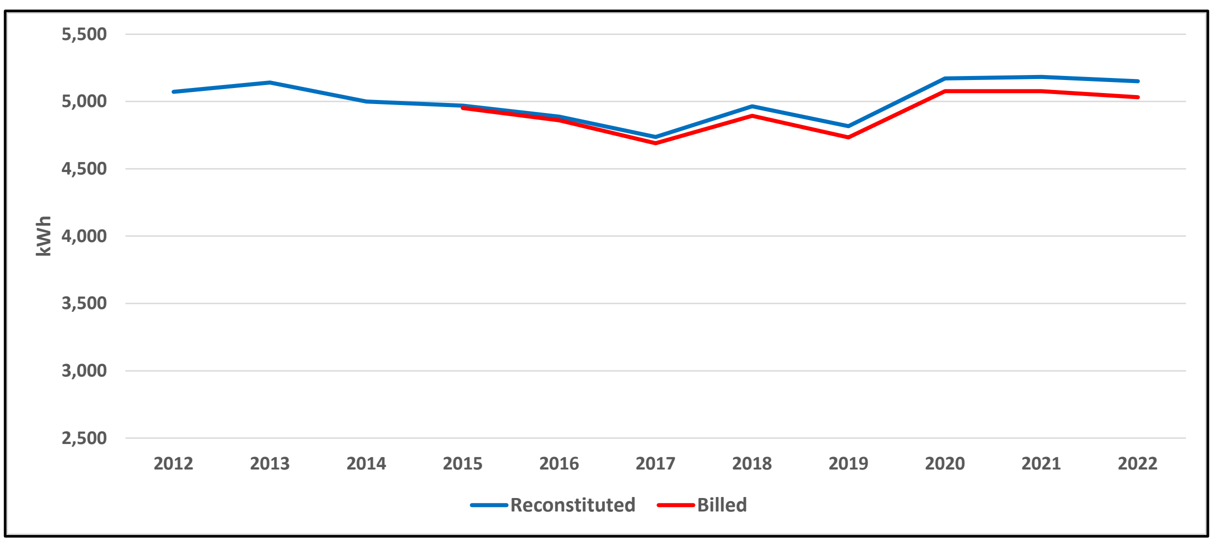
FIGURE 3: RESIDENTIAL CUSTOMERS



Customer growth has been steady with BED averaging roughly 100 new residential customers each year. Given regional household projections we expect to continue to add roughly this number of new customers over the next ten years with customer growth averaging 0.7% annual growth slowing to 0.4% growth in the following ten-year period (2032 – 42).

Figure 4 shows residential average use. The red is billed average use and the blue is the reconstituted average use. Reconstituted is the sum of billed and customer solar generation. The residential model is estimated using reconstituted average use as our objective is to model and forecast customer use – not just what is purchased from BED.

FIGURE 4: RESIDENTIAL RECONSTITUTED AVERAGE USE

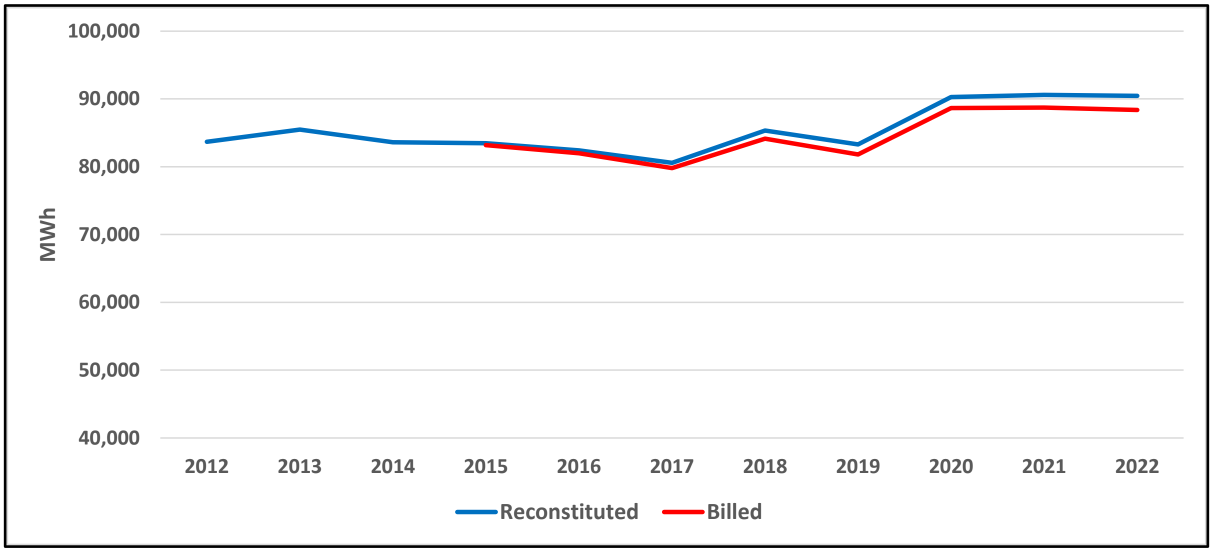


Residential billed average is around 5000 kWh per year; this is relatively low when compared with the state as BED has a much higher share of multi-family customers.

Between 2012 and 2017, average use fell 1.3% per year largely as a result of end-use efficiency gains and BED energy efficiency program activity. Average use bottom-out in 2017 and saw a large increase in 2020 as the state implemented a work at home mandate in response to COVID-19. Since 2020 average use has been declining but a very small rate. We expect to see some drop in average use in 2023, but still holding at somewhat higher base level as a relatively large share of households continue to work from home.

Figure 5 shows residential sales.

FIGURE 5: RESIDENTIAL SALES



Billed sales have been relatively flat at around 88,000 MWh. Reconstituted sales are about 90,000 MWh. For the last two years reconstituted sales have been flat as customer growth has compensated for the small decline in average use. We expect to see a small drop in 2023 sales as the economy adjusts to the "new normal".

Residential Average Use Model. The residential forecast is derived as the product of the average use and customer forecast. Average use is based on what is called a Statistically Adjusted End-Use (SAE) model where average use is defined as a function of the three primary end-uses - cooling (XCool), heating (XHeat) and other use (XOther**):**

$$ResAvgUse_m = B_0 + (B_1 \times XHeat_m) + (B_2 \times XCool_m) + (B_3 \times XOther_m) + e_m$$

The end-use variables incorporate both a variable that captures short-term utilization (Use) and a variable that captures changes in end-use efficiency and saturation trends (Index). The heating variable is calculated as:

$XHeat = HeatUse \times HeatIndex$

Where

$HeatUse = f(HDD, Household\ Income, Household\ Size, Price)$

$HeatIndex = g(Heating\ Saturation, Efficiency, Shell\ Integrity, Square\ Footage)$

The cooling variable is defined as:

$XCool = CoolUse \times CoolIndex$

Where

$\mathrm{CoolUse = f(CDD, Household\ Income, Household\ Size, Price)}$

$CoolIndex = g(Cooling\ Saturation, Efficiency, Shell\ Integrity, Square\ Footage)$

XOther captures non-weather sensitive end-uses:

$XOther = OtherUse \times OtherIndex$

Where

$OtherUse = f(Seasonal\ Use\ Pattern, Household\ Income, Household\ Size, Price)$

$OtherIndex = g(Other\ Appliance\ Saturation\ and\ Efficiency\ Trends)$

The calculations of the end-use variables are presented in Appendix B. Figure 6 to Figure 8 show the constructed monthly end-use variables.

FIGURE 6: RESIDENTIAL XHEAT (KWH PER MONTH)

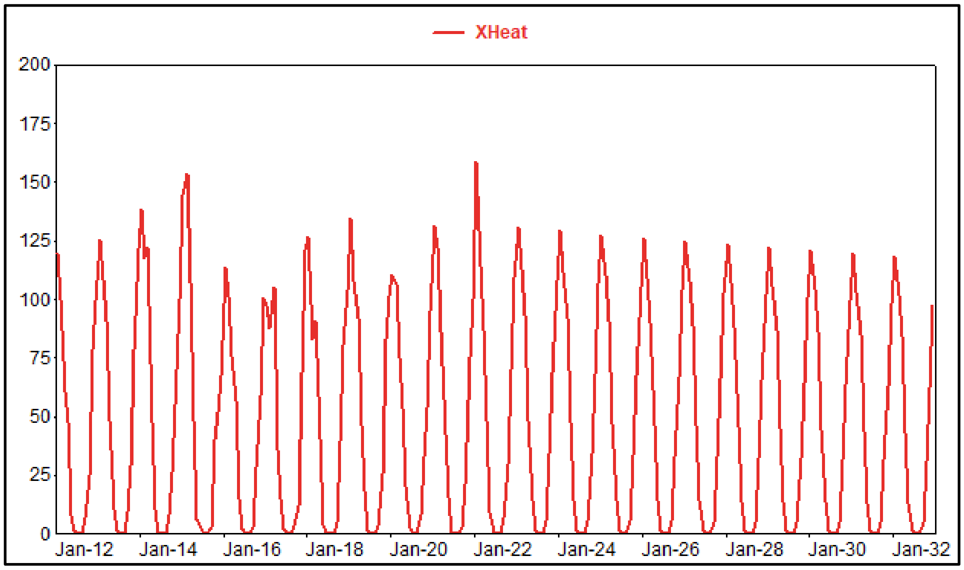


FIGURE 7: RESIDENTIAL XCOOL (KWH PER MONTH)

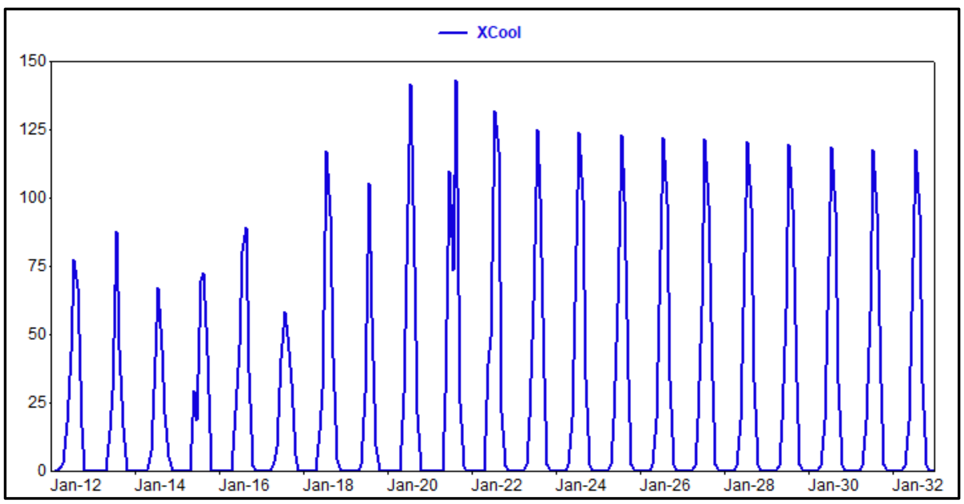
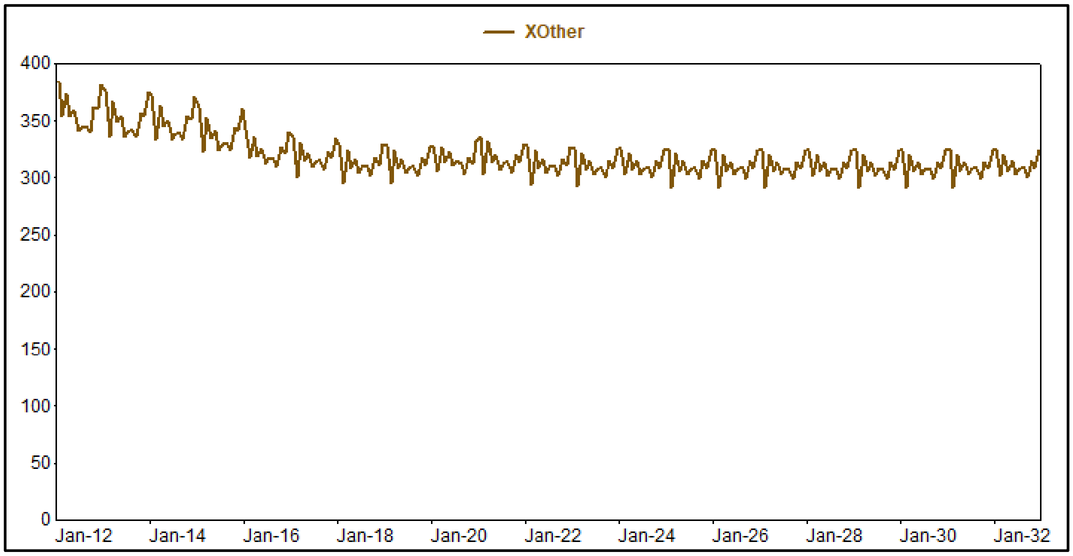


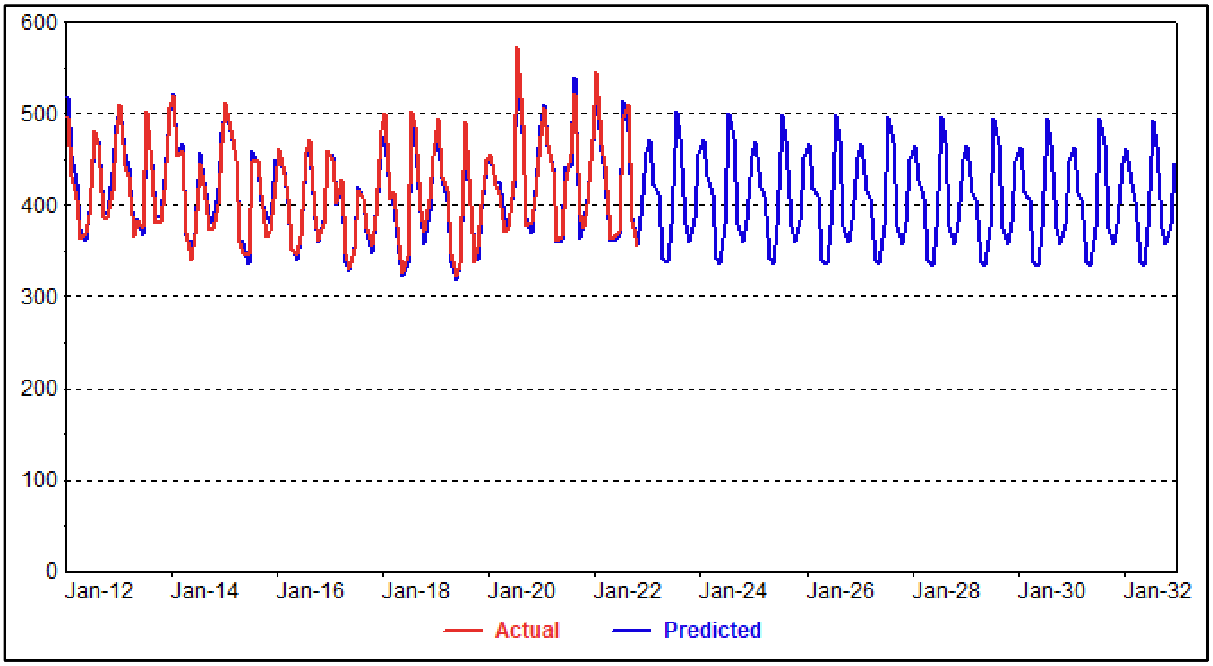
FIGURE 8: RESIDENTIAL XOTHER (KWH PER MONTH)



The heating variable (XHeat) reflects the current level of heating saturation which includes heat pumps and electric resistance. Resistant heat declines while heat pump saturation is held constant in the baseline forecast. Sales from future heat pumps are modeled separately and added back to the baseline forecast. Cooling (XCool) is small but has shown strong increase largely driven by room air conditioning and now central air conditioning growth. We again assume that most of future cooling sales growth will come from heat pump adoption which is modeled separately. XHeat and XCool also reflect expected weather trends with the number of CDD increasing and HDD decreasing. Other end-uses (XOther) are relatively flat over the next ten years as expected end-use efficiency improvements and BED efficiency program savings counter increase in miscellaneous use.

The average use model is estimated over the period January 2012 through October 2022. The model explains historical average use well with an Adjusted R^2 of 0.96 and in-sample mean absolute percent error (MAPE) of 2.0%. Figure 9 shows actual and predicted average use.

FIGURE 9: ACTUAL AND PREDICTED RES AVERAGEG USE (KWH PER MONTH)



Model coefficients and statistics are provided in **Error! Reference source not found.**.

After settling into higher post COVID usage levels, average use is expected to decline slightly at 0.1% over the first ten years and is slightly positive at the end of the 20-year period largely as a result of slowing impact of efficiency standards. Across the twenty-year period average use is flat.

Residential Customer Model. The customer forecast is based on a monthly regression model that relates the number of customers to Burlington MSA (Metropolitan Statistical Area) household projections. The model includes summer binaries to account for the seasonal variation in customer counts. As there is a strong correlation with MSA household growth the model explains customer growth well with an Adjusted R Squared of 0.97 and MAPE of 0.5%. Overall customer growth is expected to average 0.5% annual growth over the forecast period.

With flat average use and 0.5% customer growth baseline residential sales averages 0.5% growth. Table 6 shows the residential forecast excluding the impact of forecasted solar, electric vehicles and heat pumps. PV, EV, and heat pumps.

TABLE 6: RESIDENTIAL BASELINE FORECAST

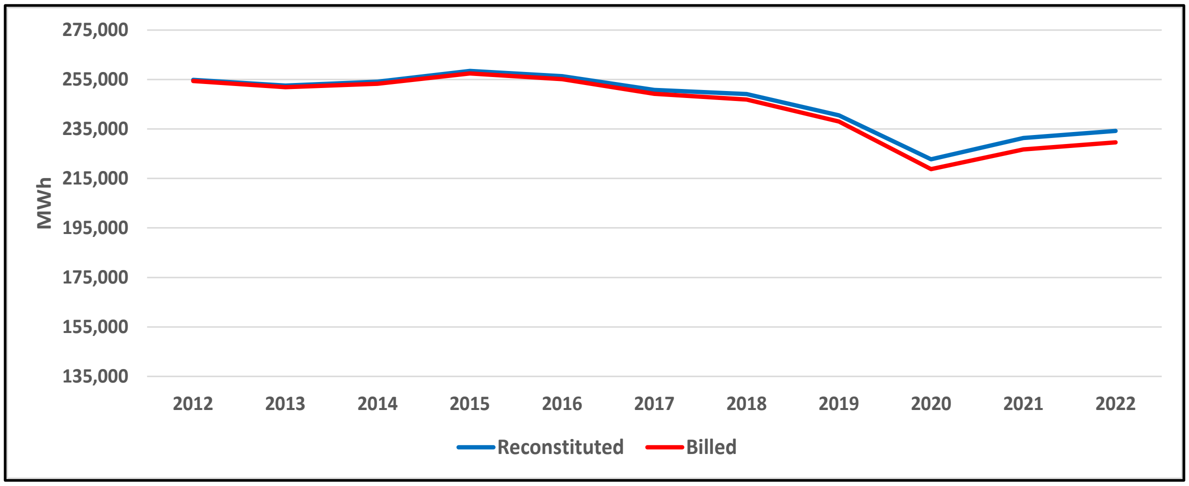
Year	Sales	Chg	Customers	Chg	Avg Use	Chg
2023	87,070		17,696		4,920	
2024	87,500	0.5%	17,774	0.4%	4,923	0.1%
2025	88,104	0.7%	17,976	1.1%	4,901	-0.4%
2026	89,507	1.6%	18,293	1.8%	4,893	-0.2%
2027	90,189	0.8%	18,484	1.0%	4,879	-0.3%
2028	90,612	0.5%	18,559	0.4%	4,882	0.1%
2029	90,569	0.0%	18,632	0.4%	4,861	-0.4%
2030	90,857	0.3%	18,701	0.4%	4,858	-0.1%
2031	91,090	0.3%	18,769	0.4%	4,853	-0.1%
2032	91,545	0.5%	18,837	0.4%	4,860	0.1%
2033	91,564	0.0%	18,905	0.4%	4,844	-0.3%
2034	91,735	0.2%	18,973	0.4%	4,835	-0.2%
2035	92,069	0.4%	19,041	0.4%	4,835	0.0%
2036	92,778	0.8%	19,109	0.4%	4,855	0.4%
2037	93,131	0.4%	19,178	0.4%	4,856	0.0%
2038	93,737	0.7%	19,246	0.4%	4,870	0.3%
2039	94,358	0.7%	19,315	0.4%	4,885	0.3%
2040	95,125	0.8%	19,384	0.4%	4,907	0.5%
2041	95,433	0.3%	19,453	0.4%	4,906	0.0%
2042	96,008	0.6%	19,522	0.4%	4,918	0.2%
23-42		**0.52%**		**0.52%**		**0.00%**

- Sales reconstituted for historical solar generation.

2.1.2 Commercial

As the business hub for Vermont, BED has a large commercial customer base. BED serves 4,000 commercial customers with total billed sales of approximately 230,000 MWh. As with residential, we forecast what is used and not billed; solar own generation is added back to billed sales. Reconstituted sales are roughly 235,000 MWh. Figure 10 shows the commercial sales trend for both billed and reconstituted sales.

FIGURE 10: COMMERCIAL SALES



Since 2015, commercial sales have been trending down largely as a result of significant energy efficiency gains in the commercial sector with both end-use standards and efficiency programs contributing to lower use. BED also saw a large drop in commercial sales with the closing of the downtown mall with COVID contributing to another large drop in 2022. sales. While there has been some recovery, sales appear to be leveling off.

Commercial Sales Model. The commercial model is also specified with an SAE framework where sales (rather than average use) is modeled as function of commercial heating (XHeat), cooling (XCool), and all other commercial end-uses (XOther). The model variables are derived by combining end-use intensities (measured in kWh per square foot) with drivers that capture price, economic activity, and growth (ComVar), and weather (HDD and CDD):

- $XHeat_m = EI_{heat} \times Price_m^{-0.10} \times ComVar_m \times HDD_m$
- $XCool_m = EI_{cool} \times Price_m^{-0.10} \times ComVar_m \times CDD_m$
- $XOther_m = EI_{other} \times Price_m^{-0.10} \times ComVar_m$

The coefficients on price are imposed short-term price elasticities. The forecast model is then specified as:

$$ComSales_m = B_0 + B_1 XHeat_m + B_2 XCool_m + B_3 XOther_m + e_m$$

Linear regression is used to estimate the model coefficients (B_0, B_1, B_2, and B_3). In addition to the end-use variables the estimated model includes a variable to account for the loss of load due to the mall closing and monthly binaries to account for seasonal shifts. The impact of COVID is captured in the economic data; there was a large drop in 2020 employment and small drop economic output.

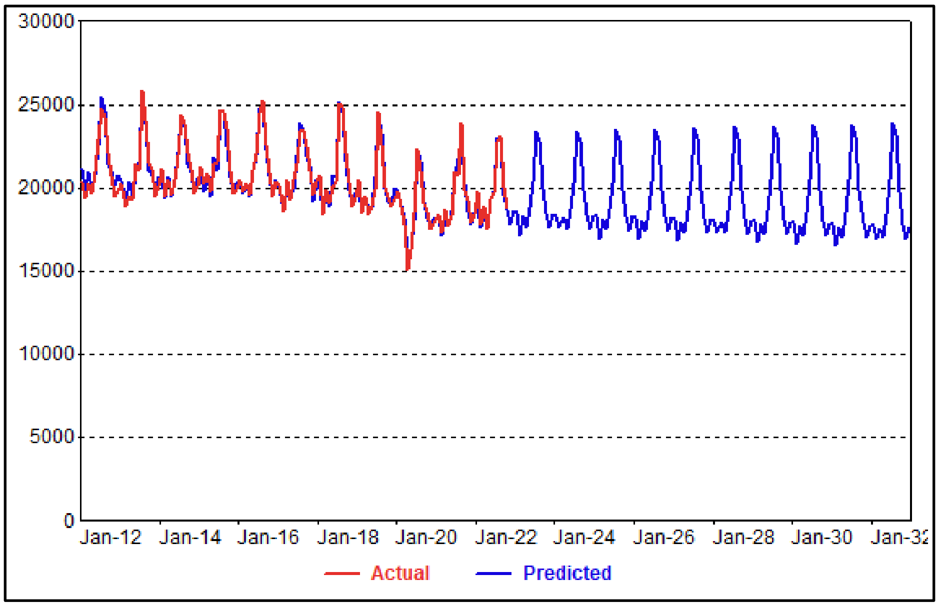
The economic variable *ComVar* is a weighted variable that includes employment and regional output. *ComVar* is defined as:

$$ComVar_m = (ComEmploy_m^{0.8}) \times (ComOutput_m^{0.2})$$

The weights were determined by evaluating the in-sample and out-of-sample model statistics for different sets of employment and output weights.

The model is estimated with monthly sales from January 2012 to October 2022. The resulting commercial sales model performs well with an Adjusted R^2 of 0.95 and an in-sample MAPE of 1.6%. Figure 11 shows actual and predicted monthly commercial energy.

FIGURE 11: ACTUAL AND PREDICTED COMMERCIAL SALES (MWH)



Commercial sales are relatively flat through the forecast period with continued improvements in end-use and building efficiency offsetting customer and economic growth. The estimated model coefficients and model statistics are included in Appendix A.

The customer forecast is based on a linear regression model that relates number of customers to employment in the Burlington MSA. Table 7 shows the reconstituted commercial sales and customer forecast. This excludes additional solar generation impacts, heat pumps, and EV sales.

TABLE 7: COMMERCIAL FORECAST

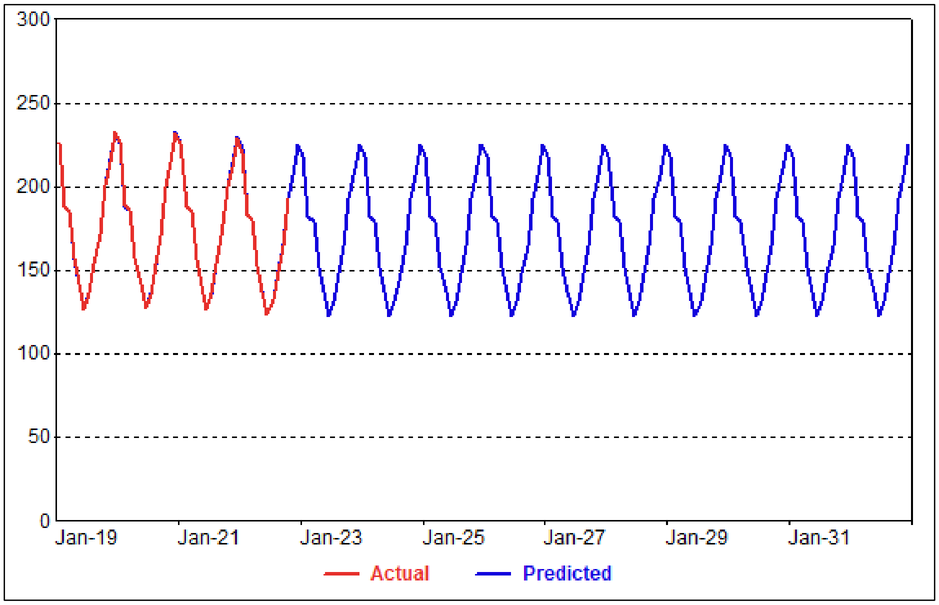
Year	Sales	Chg	Customers	Chg	Avg Use	Chg
2023	231,280		3,980		58,108	
2024	230,906	-0.2%	4,016	0.9%	57,490	-1.1%
2025	230,051	-0.4%	4,034	0.4%	57,026	-0.8%
2026	229,651	-0.2%	4,051	0.4%	56,695	-0.6%
2027	229,316	-0.1%	4,064	0.3%	56,426	-0.5%
2028	229,558	0.1%	4,076	0.3%	56,322	-0.2%
2029	228,658	-0.4%	4,087	0.3%	55,946	-0.7%
2030	227,878	-0.3%	4,098	0.3%	55,609	-0.6%
2031	227,232	-0.3%	4,108	0.3%	55,310	-0.5%
2032	227,284	0.0%	4,119	0.3%	55,181	-0.2%
2033	226,297	-0.4%	4,129	0.3%	54,802	-0.7%
2034	225,794	-0.2%	4,140	0.3%	54,540	-0.5%
2035	225,529	-0.1%	4,151	0.3%	54,337	-0.4%
2036	226,126	0.3%	4,161	0.3%	54,342	0.0%
2037	225,596	-0.2%	4,172	0.3%	54,077	-0.5%
2038	225,799	0.1%	4,182	0.3%	53,988	-0.2%
2039	226,076	0.1%	4,193	0.3%	53,917	-0.1%
2040	226,722	0.3%	4,204	0.3%	53,933	0.0%
2041	226,369	-0.2%	4,214	0.3%	53,713	-0.4%
2042	226,699	0.1%	4,225	0.3%	53,654	-0.1%
23-42		**-0.10%**		**0.31%**		**-0.42%**

- Sales reconstituted for historical solar generation.

2.1.3 Street Lighting Sales

Street lighting sales are projected using an exponential smoothing model with a seasonal component. Streetlighting sales are expected to be flat throughout the forecast period as the impact of new installations is mitigated by increasing efficiency. Figure 12 shows actual and projected street light sales.

FIGURE 12: STREET LIGHT SALES (MWH)



2.2 BASELINE SYSTEM LOAD FORECAST (STEP 2)

System energy, peak, and hourly load forecast is based on the residential, commercial, and street light sales forecasts. The energy forecast is calculated by applying the system loss factor (1.023) to the sales forecast. The peak forecast is derived from a linear regression model that relates peak demand to heating and cooling requirements, and non-weather sensitive end-use loads at time of the peak. The baseline system hourly forecast is constructed by combining revenue class hourly load profiles based on AMI data with the class sales forecast. Resulting energy, peak, and profile forecasts are combined to generate the long-term baseline system hourly load forecast.

2.2.1 Peak Forecast Model

The peak forecast is based on a monthly demand model that relates peak demand to peak-day heating, cooling, and base load requirements:

$$Peak_m = B_0 + B_1 HeatVar_m + B_2 CoolVar_m + B_3 BaseVar_m + e_m$$

The peak-day heating and cooling variables ($HeatVar_m$ *and* $CoolVar_m$) combine heating and cooling requirements derived from the sales with peak-day weather conditions; the theory is that the impact of weather on peak demand depends on the overall heating and cooling load requirement. The base load variable ($BaseVar_m$) is an estimate of the amount of non-weather sensitive load at time of peak. Baseload energy requirement is also calculated from the residential and commercial sales models.

Heating and Cooling Model Variables

Peak-day heating and cooling loads are derived from the sales forecast models. Estimated model coefficients for heating (XHeat) and cooling variables (XCool) combined with heating and cooling variable for normal weather conditions (*NrmXHeat* and *NrmXCool*) gives an estimate of the monthly heating and cooling load requirements.

Heating requirements are calculated as:

- $HeatLoad_m = B_1 \times ResNrmXHeat_m + C_1 \times ComNrmXheat_m$

B_1 and C_1 are the coefficients on *XHeat* in the residential and commercial models.

Cooling requirements are estimated in a similar manner:

- $CoolLoad_m = B_2 \times ResNrmXCool_m + C_2 \times ComNrmXCool_m$

B_2 and C_2 are the coefficients on XCool in the residential and commercial models.

Figure 13 and Figure 14 show resulting historical (weather normalized) and forecasted heating and cooling load requirements.

FIGURE 13: HEATING REQUIREMENTS (MWH)

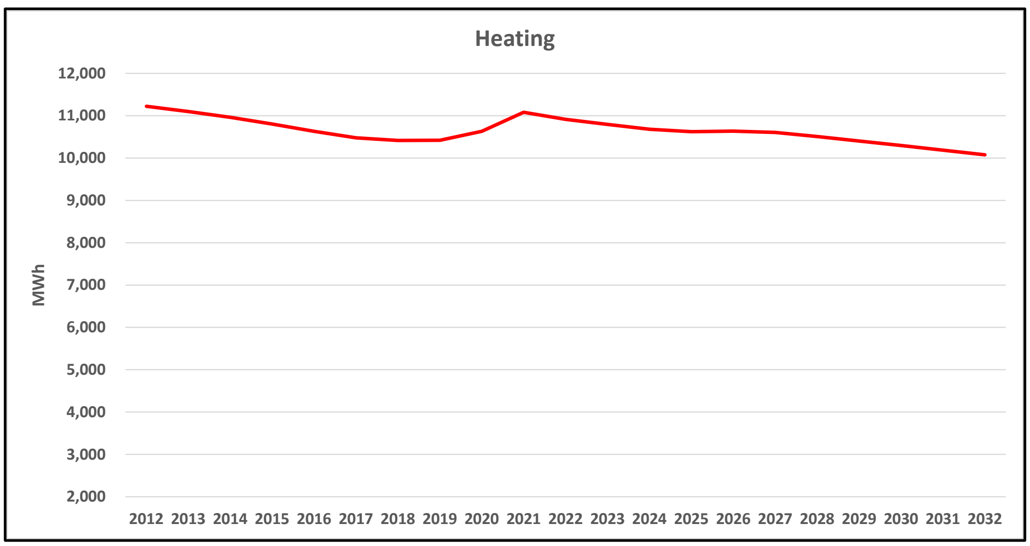
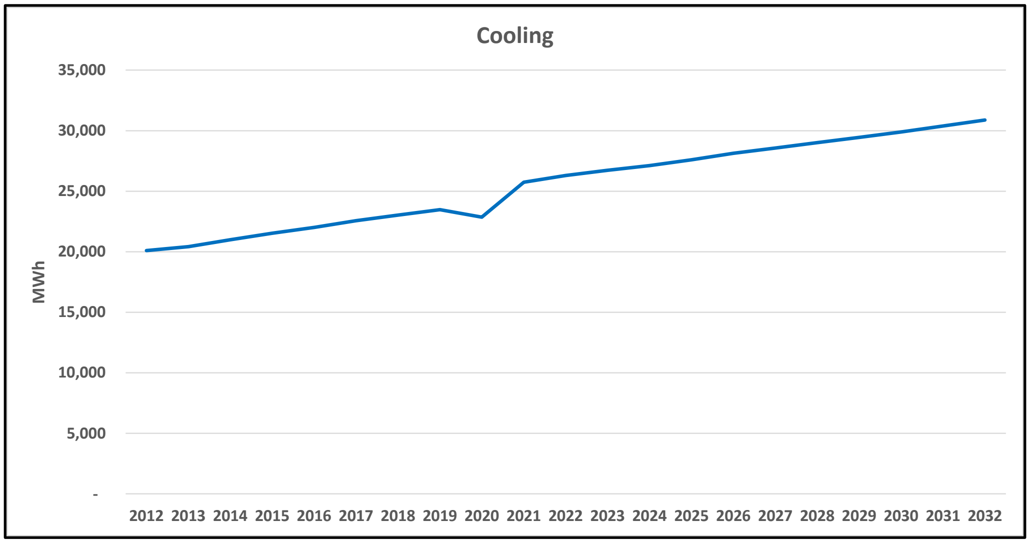


FIGURE 14: COOLING REQUIREMENTS (MWH)



Heating loads are relatively small as most heating in the BED service area is currently with natural gas. Electric heating mostly reflects resistant primary and secondary heat with some heat pump load. Heat pump loads are expected to increase significantly as BED and the state promote electrification. Incentivized heat-pumps are modeled separately. There is a jump in heating loads in 2021 reflecting the COVID related usage increase in the residential sector.

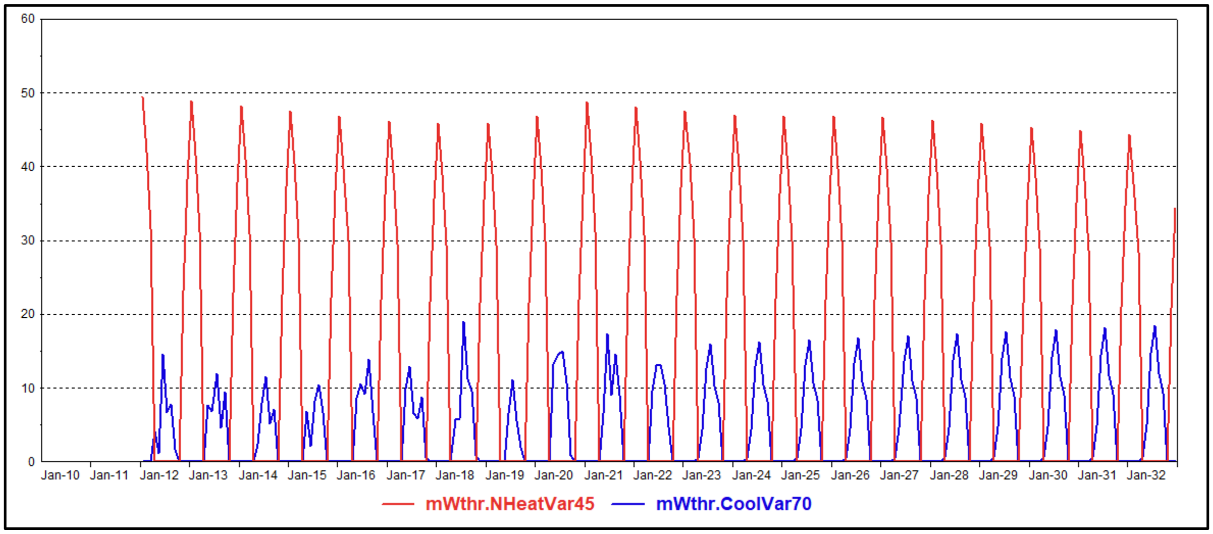
Cooling and other end-use sales are dominated by the commercial customer class given the relative sized of the sector. There is a drop in normalized cooling loads in 2020 as a result of COVID-related slowdown in business activity. Long-term increase in cooling loads is a result of continued air condition saturation growth in residential sector and economic growth in the commercial sector. Another factor driving cooling use is increasing temperatures. While cooling loads are increasing, total cooling requirements are a relatively small share of BED electricity consumption.

Peak heating and cooling model variables are calculated by combining heating and cooling energy requirements with peak-day heating and cooling degree-days:

- $HeatVar_m = HeatLoad_m \times PkHDD_m$
- $CoolVar_m = CoolLoad_m \times PkCDD_m$

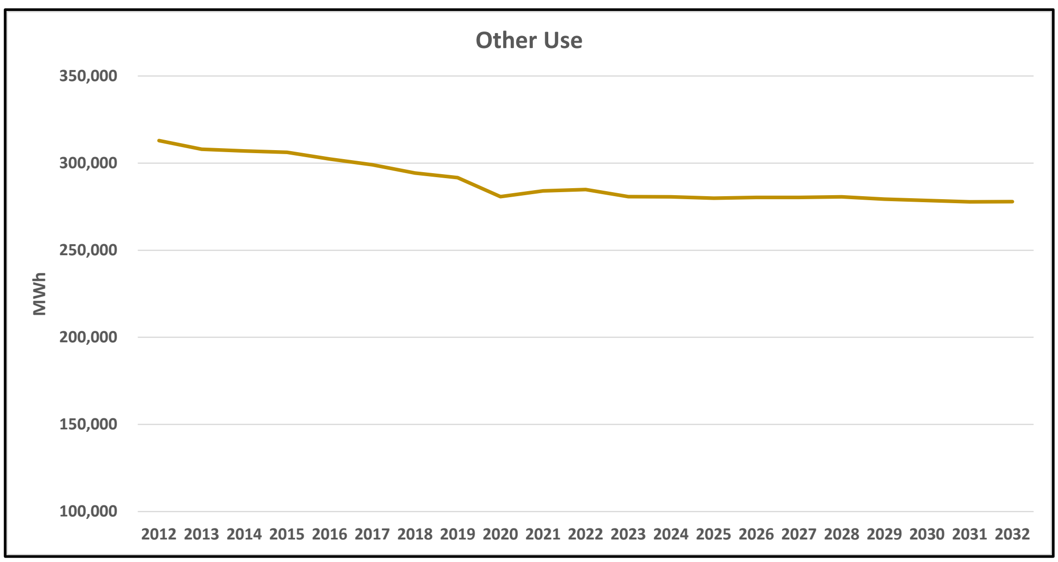
The heating and cooling loads are indexed so that the results are in HDD and CDD. Figure 15 shows the peak model heating and cooling variables.

FIGURE 15: PEAK MODEL HEATING AND COOLING VARIABLES (DEGREE DAYS)



Base Load Variable. The base-load variable ($BaseVar_m$) captures the non-weather sensitive load at the time of the monthly peak. Baseload energy requirements are also isolated from the residential and commercial sales models. Figure 16 shows the non-weather sensitive end-use sales. System base loads are dominated by the commercial sector.

FIGURE 16: BASELOADS



The base load variable is defined as:

$$BaseVar_m = ResOtherCP_m + ComOtherCP_m + StLightingCP_m$$

Where

- *ResOther* CP_m = *residential coincident peak load*
- *ComOther* CP_m = *commercial coincident peak load*
- *StLightingCP*$_m$ = *street lighting coincident peak load*

The Baseload is allocated to specific end-uses based on the end-use's share of non-weather sensitive sales. Estimated end-use load at time of peak are derived by multiplying end-use energy estimate by the fraction of load at time of the monthly peaks. Fractions vary across the year and end-uses; fractions are based on end-use load profiles developed by Itron. For example, the residential water heating coincident peak load estimate is derived as:

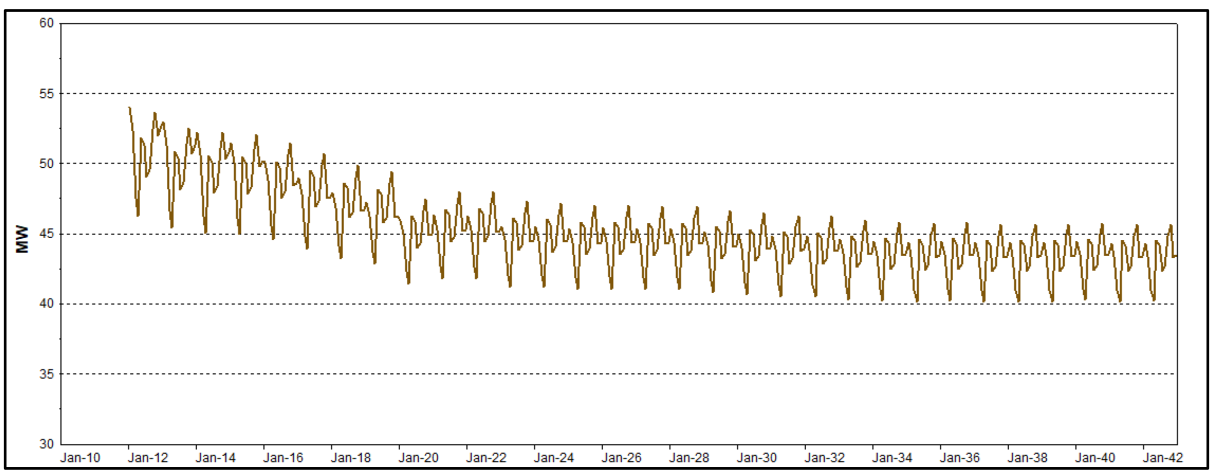
$$ResWaterCP_m = ResBaseLoad_a \times \left({}^{ResWaterEI_a}/_{ResBaseEI_a} \right) \times ResWaterFrac_m$$

Where

- *ResBaseLoad* = Annual non-residential non-weather sensitive sales
- *ResWaterEI* = Annual water heating intensity (water use per household)
- *ResBaseEI* = Annual base-use intensity (non-weather sensitive use per household)
- *ResWaterFrac* = Monthly fraction of usage at time of peak

End-use coincident peak load estimates are aggregated to revenue class and then summed across revenue classes. Figure 17 shows the peak model base load variable.

FIGURE 17: BASE LOAD VARIABLE



There has been a steady decline in system baseloads largely as a result of energy efficiency gains. The 2020 baseload drop reflects the impact of COVID on commercial sales. Going forward baseloads continue to decline, but at a slower rate.

Model Results. The peak model is estimated over the period January 2012 to October 2022. The model explains monthly peak variation well with an adjusted R^2 of 0.94 and an in-sample MAPE of 2.5%. Figure 18 shows actual and predicted results. Model statistics and parameters are included in Appendix A.

FIGURE 18: PEAK MODEL (MW)

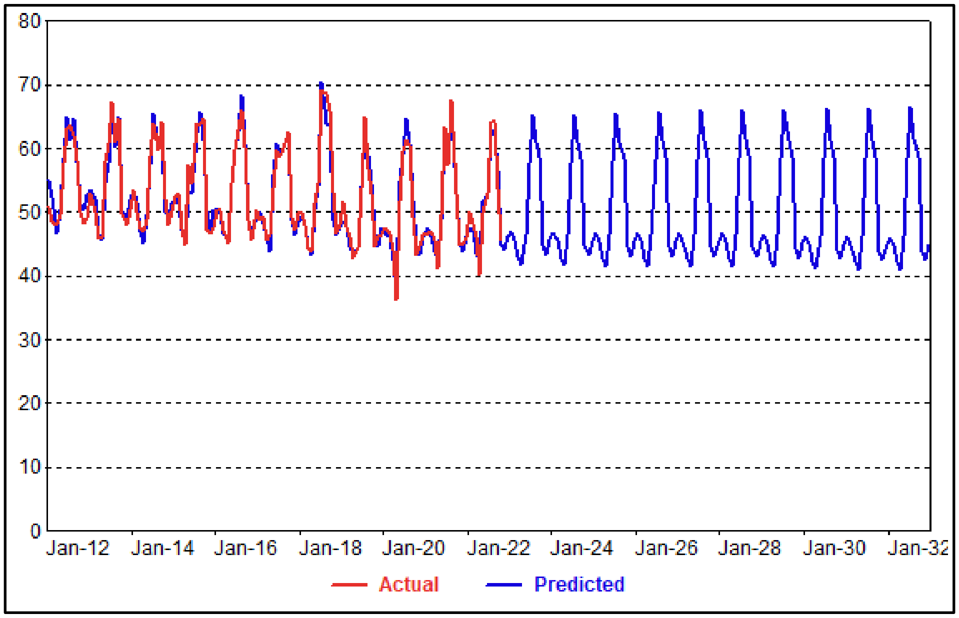


Table 8 shows baseline energy and peak demand.

TABLE 8: BASELINE ENERGY AND PEAK FORECAST

Year	Energy (MWh)	Chg	SumPk (MW)	Chg	Wint Pk (MW)	Chg
2023	327,778		65.2		50.9	
2024	327,836	0.0%	65.3	0.2%	50.8	-0.1%
2025	327,578	-0.1%	65.4	0.2%	50.7	-0.3%
2026	328,605	0.3%	65.7	0.5%	50.7	0.1%
2027	328,960	0.1%	65.9	0.3%	50.7	-0.1%
2028	329,640	0.2%	66.1	0.4%	50.7	0.0%
2029	328,676	-0.3%	66.1	0.0%	50.4	-0.5%
2030	328,172	-0.2%	66.2	0.1%	50.3	-0.3%
2031	327,751	-0.1%	66.3	0.2%	50.1	-0.3%
2032	328,270	0.2%	66.6	0.4%	50.1	-0.1%
2033	327,278	-0.3%	66.6	0.0%	49.8	-0.5%
2034	326,938	-0.1%	66.7	0.2%	49.7	-0.3%
2035	327,008	0.0%	66.9	0.3%	49.6	-0.2%
2036	328,345	0.4%	67.3	0.6%	49.6	0.1%
2037	328,164	-0.1%	67.5	0.3%	49.5	-0.3%
2038	328,993	0.3%	67.8	0.5%	49.5	0.0%
2039	329,909	0.3%	68.2	0.6%	49.5	0.0%
2040	331,357	0.4%	68.7	0.7%	49.6	0.1%
2041	331,310	0.0%	68.9	0.4%	49.4	-0.3%
2042	332,237	0.3%	69.3	0.6%	49.4	0.0%
23-42		**0.1%**		**0.3%**		**-0.2%**

- Energy and peak include historical solar generation.

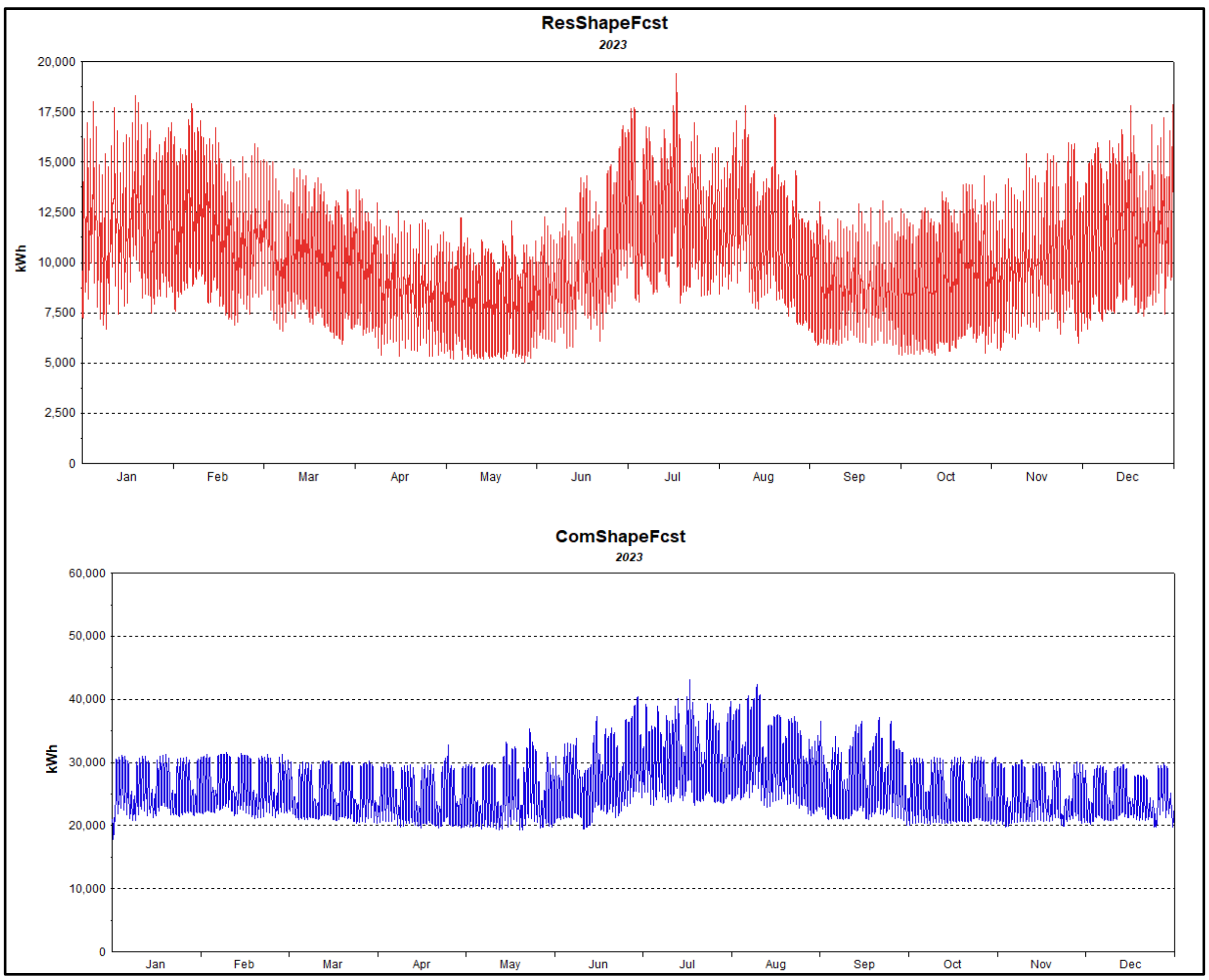
The baseline energy and peak forecasts are relatively flat as continued improvements in energy efficiency mitigate increasing energy requirements from customer and regional economic growth.

2.2.2 System Hourly Load Forecast

The baseline hourly load forecast is generated by aggregating the residential, commercial, and street lighting hourly load forecasts. Class hourly load forecasts are derived by combining class hourly load profiles estimated from AMI data with class sales forecast.

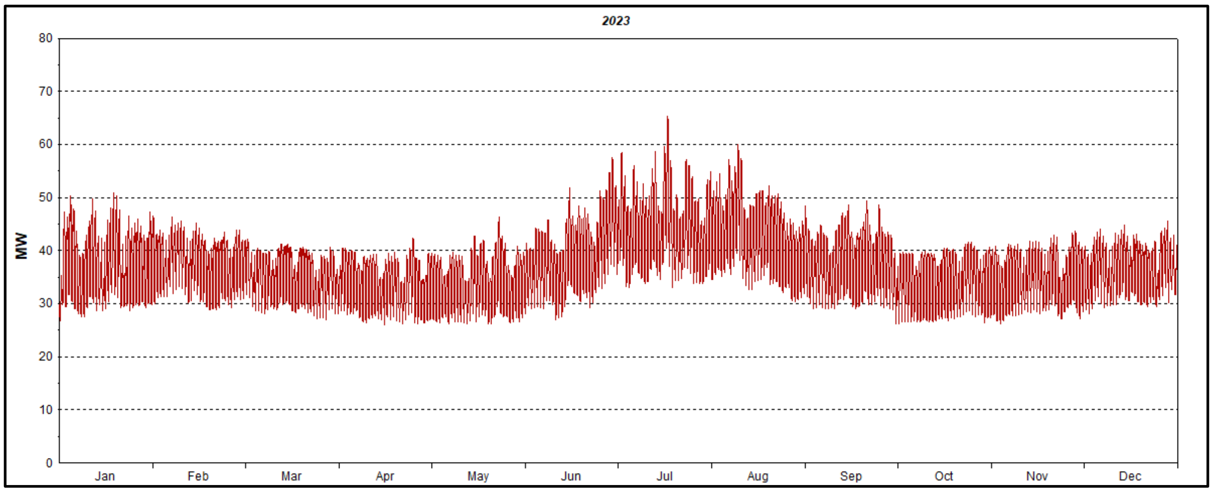
Class Hourly Load Profiles. Residential, commercial, and street lighting hourly profiles are derived from historical AMI data. The profile models are relatively simple; variables daily average degree-days, day of the week, holidays, seasonal/ monthly binaries, hours of light, and a COVID variable to account for any related load changes due to changes in home and business activity. Figure 19 shows the rate class profiles for 2023. Profiles are extended through 2042.

FIGURE 19: RATE CLASS PROFILES



Baseline Hourly Load Forecast. Baseline system load forecast is developed using a product called MetrixLT. MetrixLT is designed for building long-term system hourly load forecasts. The baseline system load forecast is calculated by combining rate class sales forecast with the rate class hourly loads and summing the rate class hourly load forecasts. The hourly load profiles are adjusted for line losses and calibrated to the system peak forecast. An 8,760 baseline forecast is estimated for each year through 2042. Figure 20 shows the resulting baseline hourly load forecast for 2023.

FIGURE 20: BASELINE SYSTEM LOAD FORECAST (2023)



Given the relative size of the commercial sector, the baseline system load forecast peaks in the summer through the entire forecast period.

2.3 ADJUSTED LOAD FORECAST (STEP 3)

The baseline load forecast is fairly constant through the forecast period. It is the expected adoption of more solar, heat pumps, and electric vehicles that reshape system load over time and drives energy and peak demand. The adjusted load forecast is produced by adding additional solar, heat pump, and electric vehicle hourly load forecasts to the baseline forecast. Figure 21 shows projected PV and EV hourly loads for the July peak week in 2032.

FIGURE 21: NEW TECHNOLOGY LOADS (MWH)

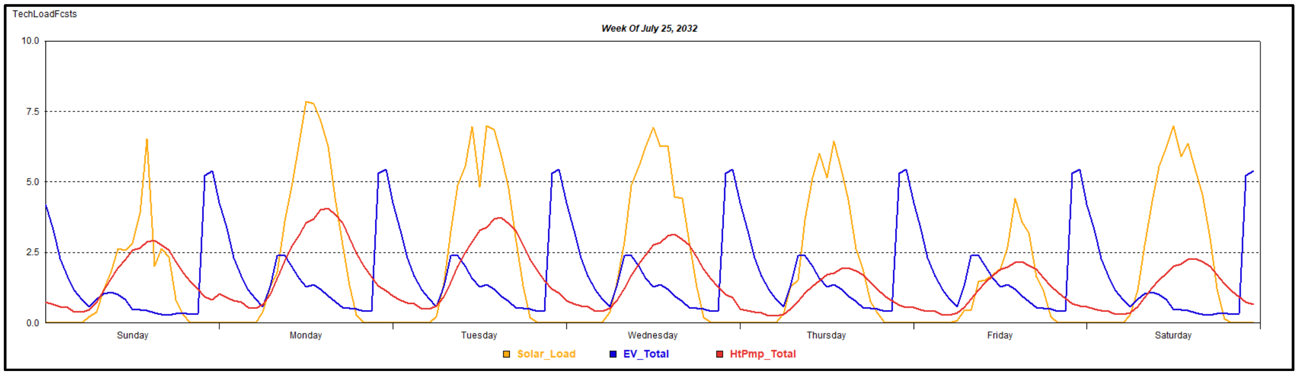
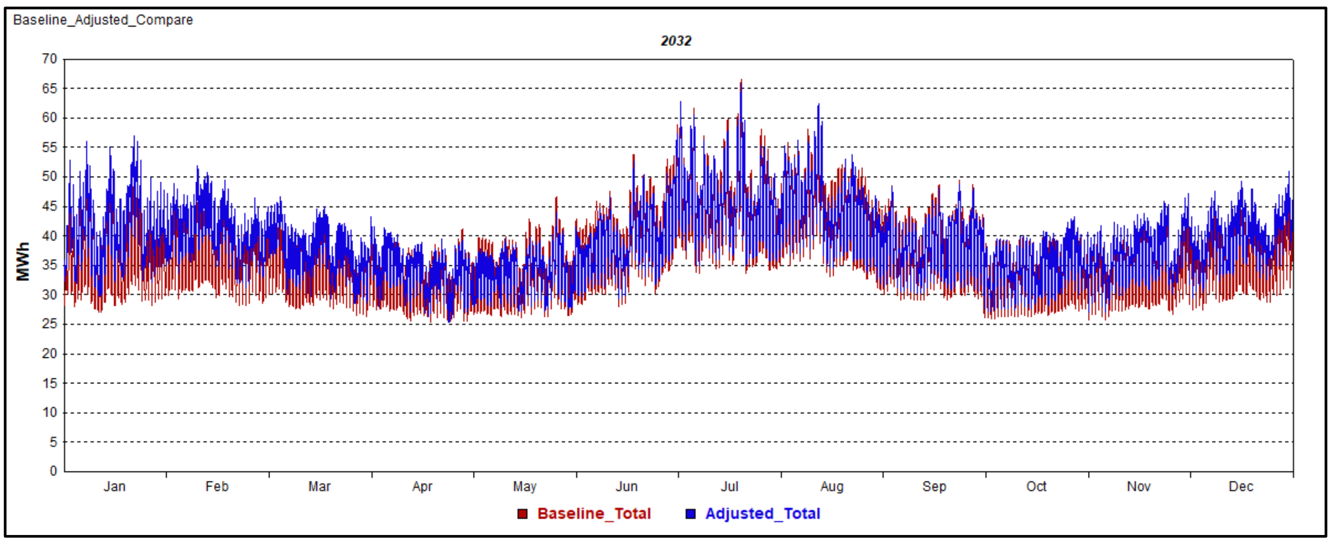


Figure 22 shows the 2032 adjusted load forecast (in blue) against the baseline load forecast (in red). The adjusted winter loads are significantly higher as a result of projected heat pump and EV loads. The impact to summer loads is muted as load reduction from solar generation is roughly equal to heat pump cooling and EV on-peak-loads.

FIGURE 22: BASELINE VS. ADJUSTED LOADS (MWH)



2.4 SOLAR FORECAST

The BED energy and peak forecast incorporates the impact of expected behind the meter photovoltaic adoption. Prior to 2020, BED averaged 500-600 kW of solar capacity added each year. In 2020, 1,200 kW of capacity was added as result of two large commercial solar system installations that total 800 kW. Since 2021, approximately 400 kW of capacity has been added each year. While some of the recent adoptions are incentive-driven, continuing system cost declines will drive future long-term adoption.

2.4.1 Market Share Model

We assume that the primary factor driving PV adoption is the favorable economics from the customers' perspective – system savings outweigh initial upfront cost and related financing. Simple payback is used as a proxy for customer's return on investment. Simple payback reflects the length of time needed for a customer to recover the cost of installing a solar system - the shorter the payback, the higher the system adoption rate. There is a strong correlation between adoption and simple payback. The payback calculation is based on total installed cost, annual savings from reduced energy bills, and incentive payment for excess and own-use generation.

Simple payback declines over the forecast period largely as a result of declining system cost. System costs have been declining rapidly over the last five years. In 2015, the average residential solar system costs approximately $3.50 per watt; by 2022 costs have dropped to $2.60 per watt. For the forecast we assume that system costs continue to decline 5% annually through 2024, at which point costs continue to decline at 2% a year.

The PV adoption model relates the share of customers that have adopted solar systems to simple payback through a cubic model specification. A cubic model specification results in an S-shaped adoption curve. Figure 23 and Figure 24 show the resulting market share forecast for the residential class and commercial classes.

FIGURE 23: RESIDENTIAL SOLAR SHARE FORECAST

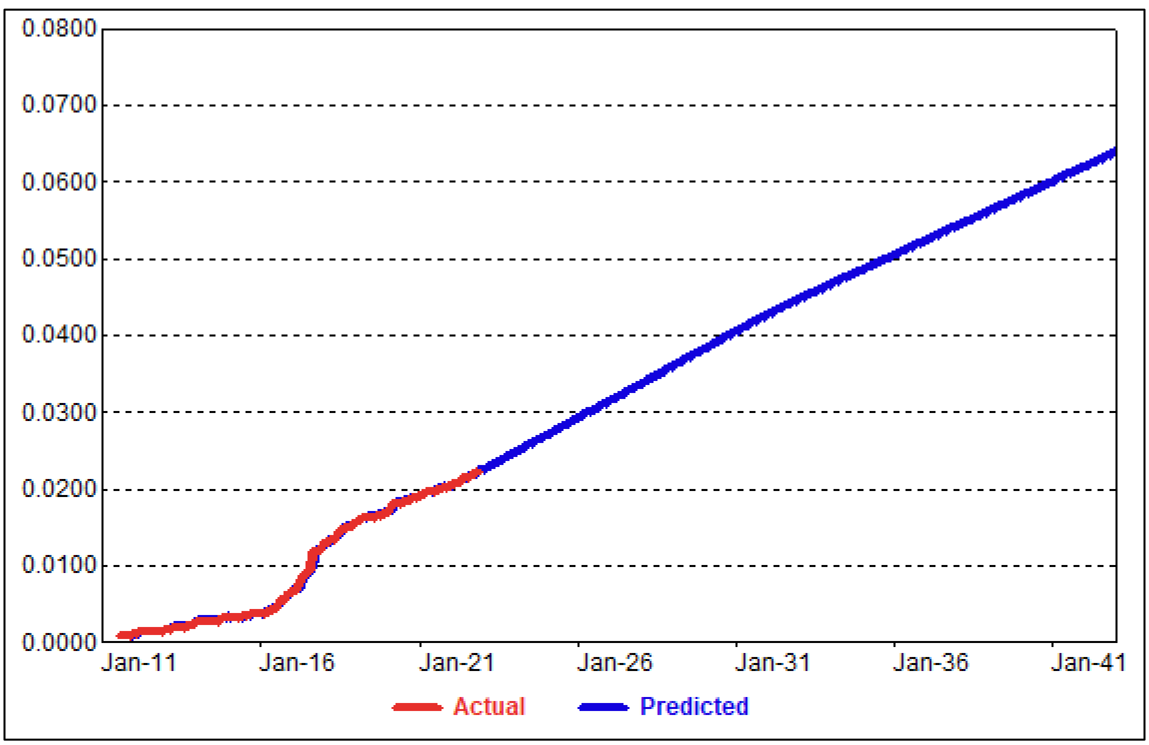
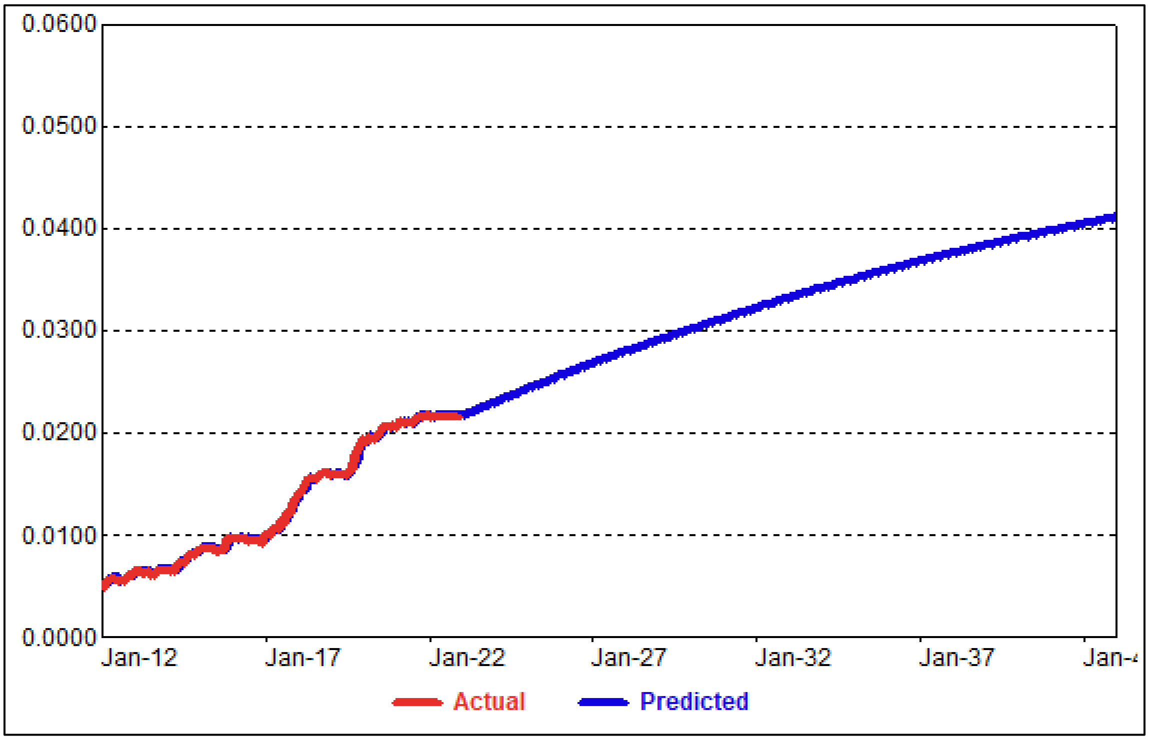


FIGURE 24: COMMERCIAL SOLAR SHARE FORECAST



As of November 2022, there were 390 residential and 88 commercial solar customer accounts, which amount to 2.23% and 2.16% market saturation. With declining system costs and incentives, residential saturation increases to 6.3% over the forecast horizon. Commercial solar saturation also increases but at a slower rate. Table 9 shows the solar share and resulting solar customer forecast.

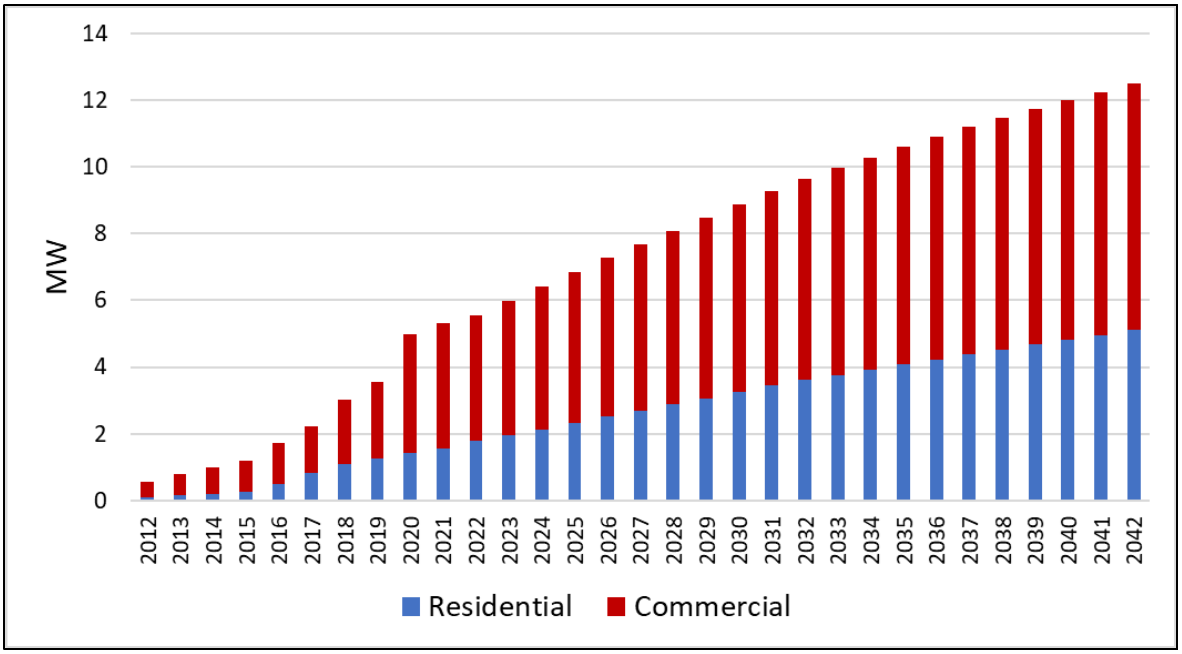
TABLE 9: SOLAR CUSTOMER FORECAST

Year	Residential	Share of Total	Commercial	Share of Total
2023	413	2.4%	90	2.2%
2024	453	2.6%	96	2.4%
2025	493	2.8%	102	2.5%
2026	534	3.0%	108	2.6%
2027	575	3.3%	113	2.7%
2028	616	3.5%	118	2.9%
2029	657	3.7%	123	3.0%
2030	699	3.9%	128	3.1%
2031	739	4.2%	132	3.2%
2032	778	4.4%	137	3.3%
2033	814	4.6%	141	3.4%
2034	848	4.8%	145	3.5%
2035	882	5.0%	149	3.6%
2036	916	5.2%	153	3.6%
2037	950	5.3%	156	3.7%
2038	982	5.5%	159	3.8%
2039	1,014	5.7%	162	3.9%
2040	1,047	5.9%	165	3.9%
2041	1,079	6.1%	167	4.0%
2042	1,110	6.3%	170	4.1%

2.4.2 Solar Capacity and Generation

The installed solar capacity forecast is the product of the solar customer forecast and an assumed average system size, both for the residential and commercial classes. The average assumed size is 4.5 KW for residential systems and 43.2 KW for commercial systems (average system size of all the systems installed through November 2022). Figure 25 shows the installed solar capacity forecast.

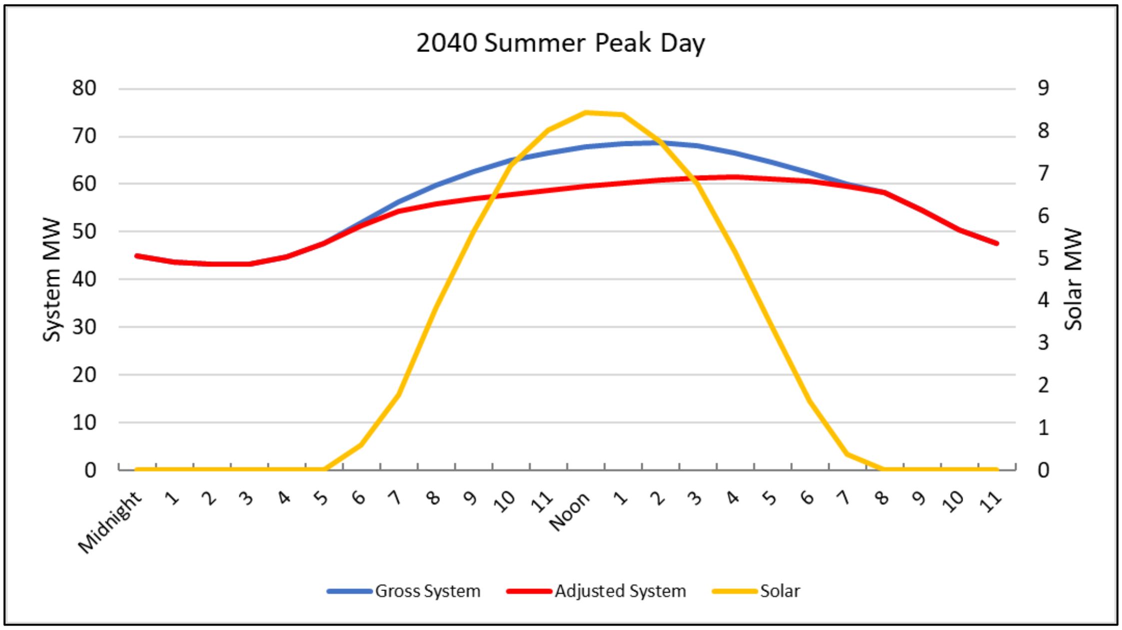
FIGURE 25: SOLAR CAPACITY FORECAST



The capacity forecast is 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 PV shape is from the National Renewable Energy Laboratory (NREL) and represents a typical meteorological year (TMY).

The impact of solar on peak demand is a function of the timing between solar load generation and system hourly demand. Even though solar capacity reaches 12.5 MW by 2042, solar load reduces system peak demand by only 7 MW. Figure 26 shows the gross system profile, solar adjusted system profile, and solar profile for a peak producing summer day (not including the impact of electric vehicles).

FIGURE 26: SOLAR HOURLY LOAD IMPACT



PV capacity has no impact on the winter peak demand as the winter peak is late in the evening when there is no solar generation. Table 10 shows the PV capacity forecast and expected annual generation impacts.

TABLE 10: SOLAR CAPACITY & GENERATION

Year	Installed Capacity MW (July)	Generaiton MWh
2023	5.8	7,175
2024	6.2	7,729
2025	6.7	8,254
2026	7.1	8,788
2027	7.5	9,311
2028	7.9	9,839
2029	8.3	10,313
2030	8.7	10,808
2031	9.1	11,290
2032	9.5	11,787
2033	9.8	12,196
2034	10.2	12,601
2035	10.5	12,999
2036	10.8	13,418
2037	11.1	13,756
2038	11.4	14,106
2039	11.6	14,445
2040	11.9	14,811
2041	12.2	15,094
2042	12.4	15,404

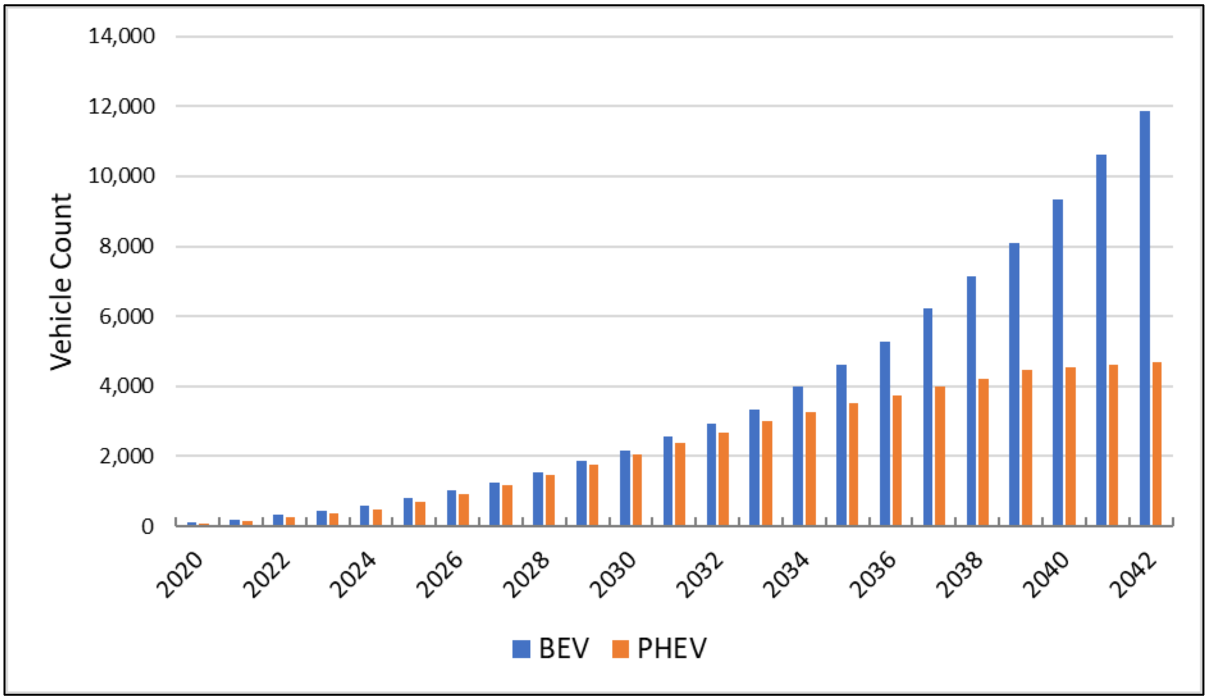
2.5 ELECTRIC VEHICLES

The BED forecast incorporates the impact of electric vehicle adoption and charging. As of 2022 there were approximately 575 electric vehicles registered in BED's service territory, accounting for 2% of registered vehicles. Of the 575 electric vehicles, 55% were all electric (BEV) and 45% were plug-in hybrid electric vehicles (PHEV). While electric vehicles currently represent a small percentage of vehicles, continued state and federal incentives, and increased investments from vehicle manufactures, will ensure their growth.

2.5.1 Electric Vehicle Forecast

The BEV/PHEV vehicle forecast is developed by BED staff, based in part on Vermont's Agency of Natural Resources Department rules limiting the sale of new fossil-fuel driven Light Duty Vehicles by 2035. Electric vehicle saturation increases from its current level of 2% to over 60% by 2042. Figure 27 shows the electric vehicle forecast.

FIGURE 27: ELECTRIC VEHICLE FORECAST



Assumptions regarding annual kWh per vehicle are based on the average efficiency ratings of 5 popular BEV/PHEV models. It's assumed vehicles are driven 8,000 miles annually with the PHEVs operating in all electric mode 50% of the time or 4,000 miles. As a result, BEVs consume 2,416 kWh annually and PHEVs consume 1,232 kWh annually.

In addition to light-duty electric vehicles, Green Mountain Transit currently operates 2 electric buses which charge in the BED service territory. When fully operational the buses are estimated to drive 30,000 miles annually and consume 53 MWh. Green Mountain Transit plans to add 5 more buses to its fleet by 2024 (and potentially 17 additional e buses by 2028).

Burlington is a regional hub for business activity, with a portion of the workforce commuting into the city from surrounding towns. Some of these commuters drive electric vehicles and take advantage of public or workplace charging during the day. This electric vehicle energy consumption is not captured in the BED electric vehicle forecast discussed above. Using public and workplace charging data, BED staff estimate 25% of public and workplace charging is for vehicles not registered in the BED service territory. Based on this information a non-BED electric vehicle consumption forecast was developed and incorporated into the forecast.

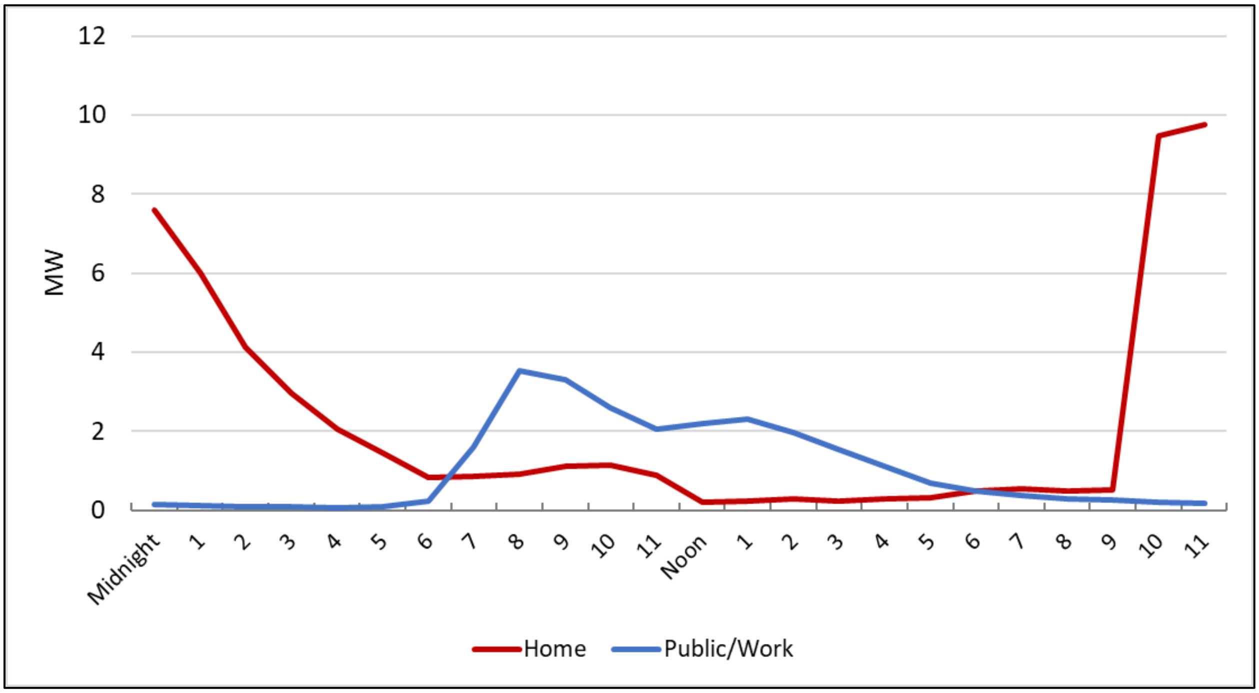
The forecast is adjusted for the impact of all new electric vehicles, Table 11 shows the energy consumed from additional electric vehicles.

TABLE 11: ELECTRIC VEHICLE FORECAST

Year	BEV MWh	PHEV MWh	Bus MWh	Non-BED Vehicle MWh
2023	300	111	9	29
2024	899	333	66	87
2025	1,450	561	136	143
2026	2,000	789	189	198
2027	2,551	1,017	242	254
2028	3,274	1,316	295	326
2029	3,996	1,615	295	399
2030	4,718	1,914	295	472
2031	5,668	2,229	295	561
2032	6,617	2,544	295	650
2033	7,567	2,859	295	739
2034	9,125	3,110	295	864
2035	10,684	3,361	295	988
2036	12,242	3,612	295	1,113
2037	14,520	3,848	295	1,284
2038	16,798	4,084	295	1,455
2039	19,077	4,320	295	1,627
2040	22,116	4,399	295	1,836
2041	25,155	4,478	295	2,045
2042	28,195	4,557	295	2,254

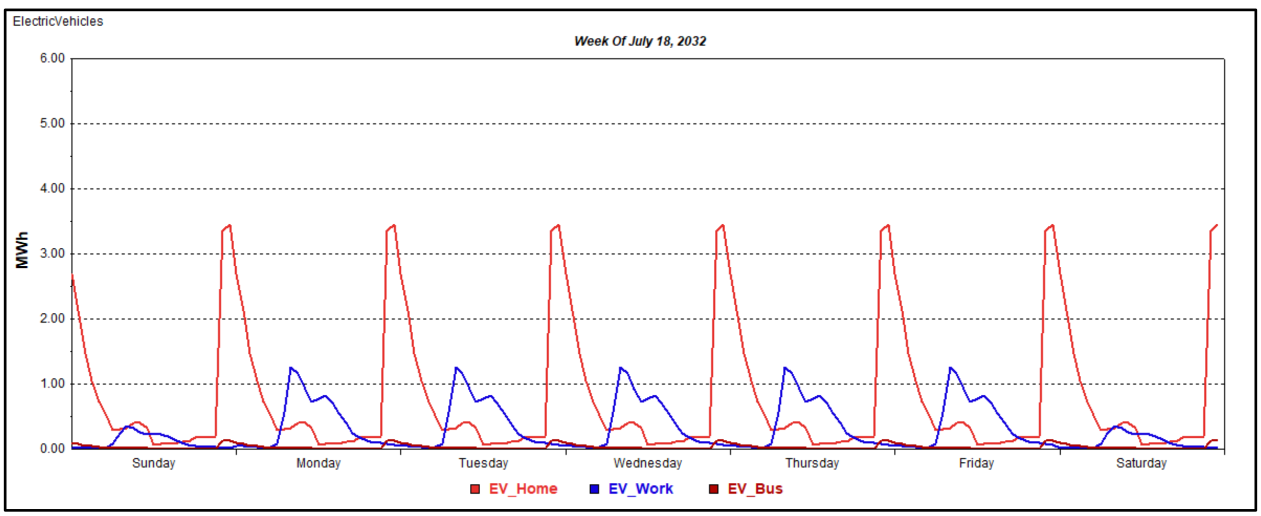
Electric vehicles' impact on the BED system profile will depend on when and where owners choose to charge their vehicles. Off-peak charging is promoted by BED's current TOU incentive electric rate for vehicle owners. Some owners may also charge away from home at either public or workplace chargers. The forecast uses two different charging profiles, a home profile in which vehicles take advantage of the TOU rate, the other a public or workplace charging. The profiles are based on historical measured charging data. BED assumes 80% of the vehicle charging will occur at home and 20% at public or workplace chargers. Electric vehicles from outside Burlington also charge on workplace chargers. Figure 28 shows the home and public/workplace charging profiles.

FIGURE 28: ELECTRIC VEHICLE CHARGING PROFILE



The EV load forecast is derived by combining EV energy requirements with the hourly charging load profiles. Figure 29 shows summer EV charging load for a July summer week in 2032.

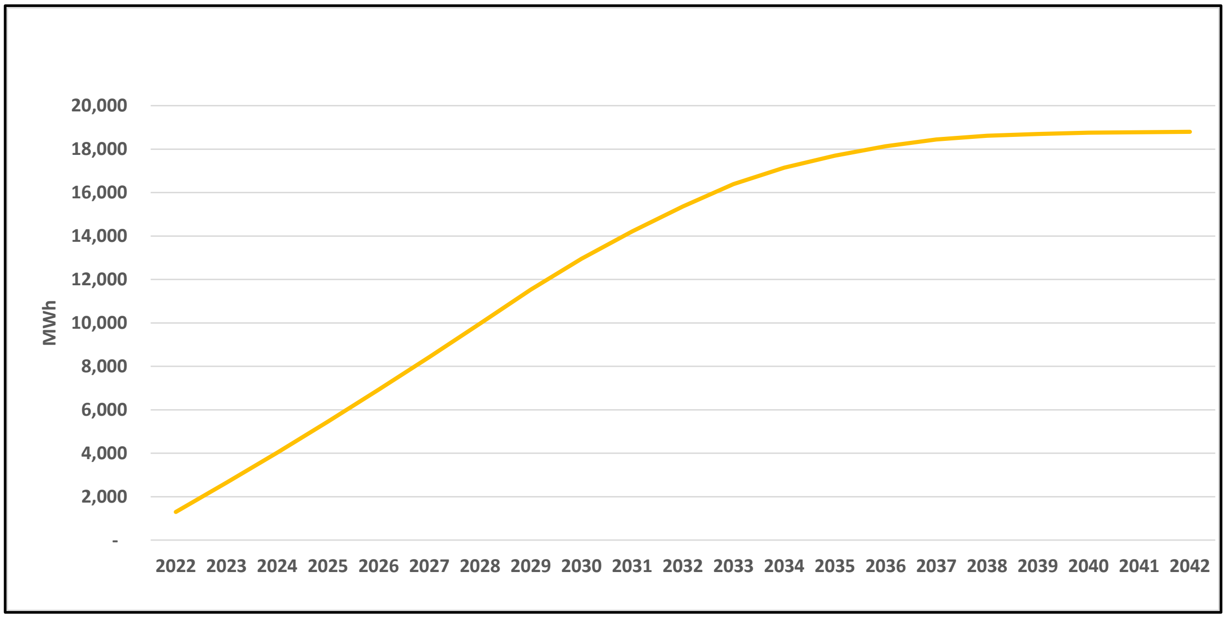
FIGURE 29: SUMMER WEEK ELECTRIC VEHICLE LOAD FORECAST (2032)



2.6 HEAT PUMPS

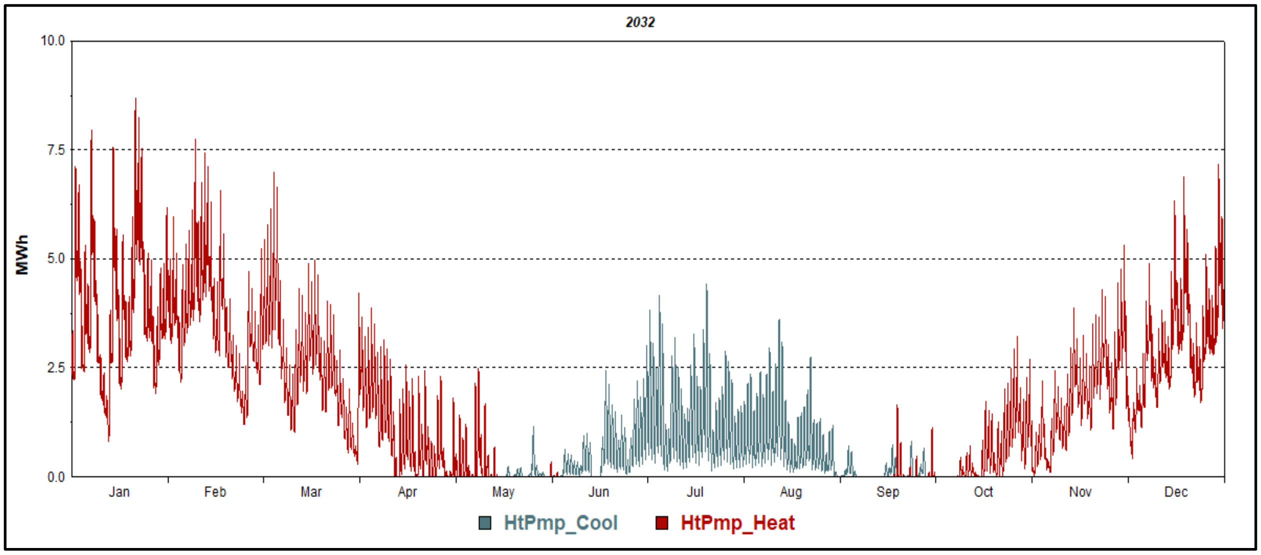
Heat pumps are being promoted through incentives to replace carbon-based heating systems (gas, oil, and propane). This is part of the effort to meet state CO2 emission target. BED is actively promoting heat pumps and is expected to have nearly 1,300 heat pumps installed by end of 2022 representing a 7% saturation in the residential customer class. The number of homes with heat pumps increases to nearly 30% by 2032 translating into 15,400 MWh of sales and 16,100 MWh by the end of the forecast period. Approximately 85% heat pump use is for heating and 15% for cooling. Figure 30 shows the heat pump energy forecast.

FIGURE 30: HEAT PUMP ENERGY FORECAST



The load forecast is derived by combining the annual heating and cooling heat pump sales with heating and cooling hourly load profiles. Profiles are estimated from a recent project that involved metering approximately 120 installed heat pump systems. Figure 31 shows heat pump load forecast for 2032.

FIGURE 31: HEAT PUMP LOAD FORECAST 2032



By 2032 heat pump maximum demand reaches nearly 9 MW in the winter and is over 4 MW in the summer.

3 FORECAST SCENARIOS

With moderate economic and customer growth coupled with continued energy efficiency improvements, the baseline forecast is effectively flat. Future growth will come from heat pumps and electric vehicles softened by further solar penetration. Given the potential impacts of heat pumps and electric vehicles, BED defined two scenarios, a high and low, based on alternative heat pump and electric vehicle market penetration paths. Table 12 and Table 13 show the Low, Base, and High heat pump and EV forecasts. Forecasts show the expected cumulative new units and vehicles starting in 2023.

TABLE 12: HEAT PUMP PROJECTIONS (UNITS)

Year	Low	Base	High
2023	329	410	1,128
2024	669	834	2,295
2025	1,020	1,273	3,503
2026	1,382	1,725	4,747
2027	1,753	2,188	6,021
2028	2,134	2,664	7,331
2029	2,523	3,151	8,671
2030	2,875	3,590	9,879
2031	3,189	3,984	10,963
2032	3,474	4,340	11,942
2033	3,729	4,660	12,822
2034	3,920	4,899	13,480
2035	4,063	5,078	13,972
2036	4,171	5,213	14,343
2037	4,250	5,313	14,618
2038	4,293	5,365	14,762
2039	4,314	5,391	14,834
2040	4,326	5,406	14,876
2041	4,332	5,414	14,898
2042	4,337	5,419	14,913

TABLE 13: ELECTRIC VEHICLE PROJECTIONS

Year	Low	Base	High
2023	188	235	235
2024	376	470	470
2025	741	926	1,099
2026	1,106	1,382	1,728
2027	1,470	1,838	2,357
2028	1,949	2,436	3,174
2029	2,427	3,034	3,991
2030	2,906	3,632	4,808
2031	3,472	4,340	5,830
2032	4,038	5,048	6,852
2033	4,605	5,756	7,874
2034	5,322	6,652	9,006
2035	6,039	7,548	10,138
2036	6,755	8,444	11,317
2037	7,698	9,623	12,574
2038	8,642	10,802	13,831
2039	9,585	11,981	15,088
2040	10,654	13,318	16,581
2041	11,724	14,655	18,074
2042	12,793	15,992	19,567

Number of EVs and heat pumps are translated into sales. Figure 32 shows Base, High, and Low EV energy forecast.

FIGURE 32: ELECTRIC VEHICLE CHARGING FORECAST

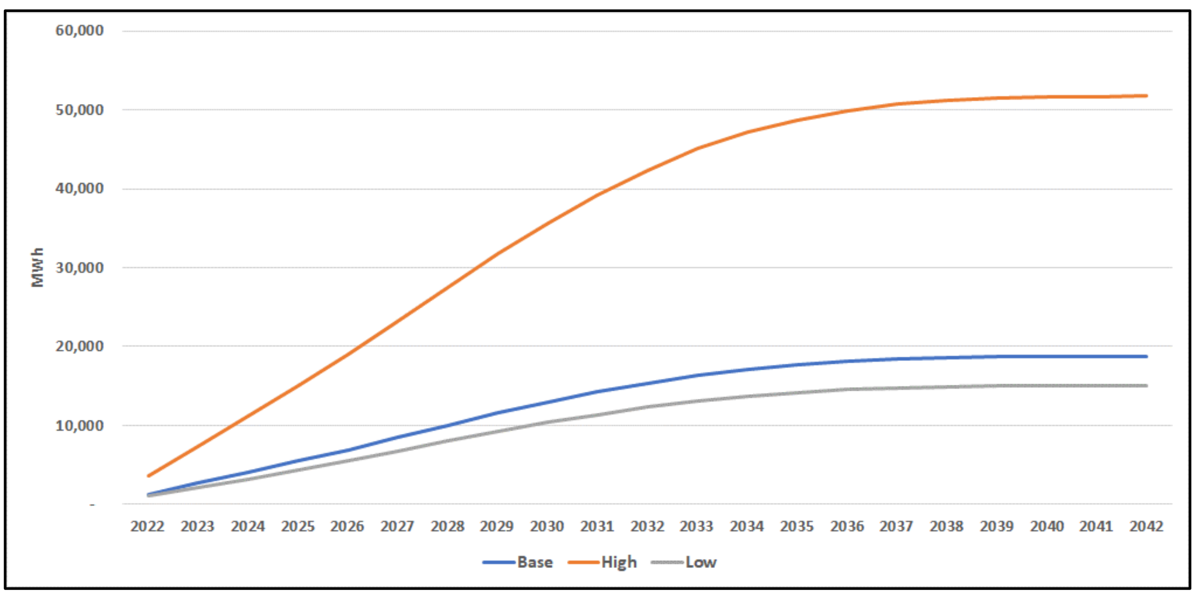


Figure 33 shows Base, High, and Low Heat Pump sales forecast.

FIGURE 33: HEAT PUMP SALES FORECAST

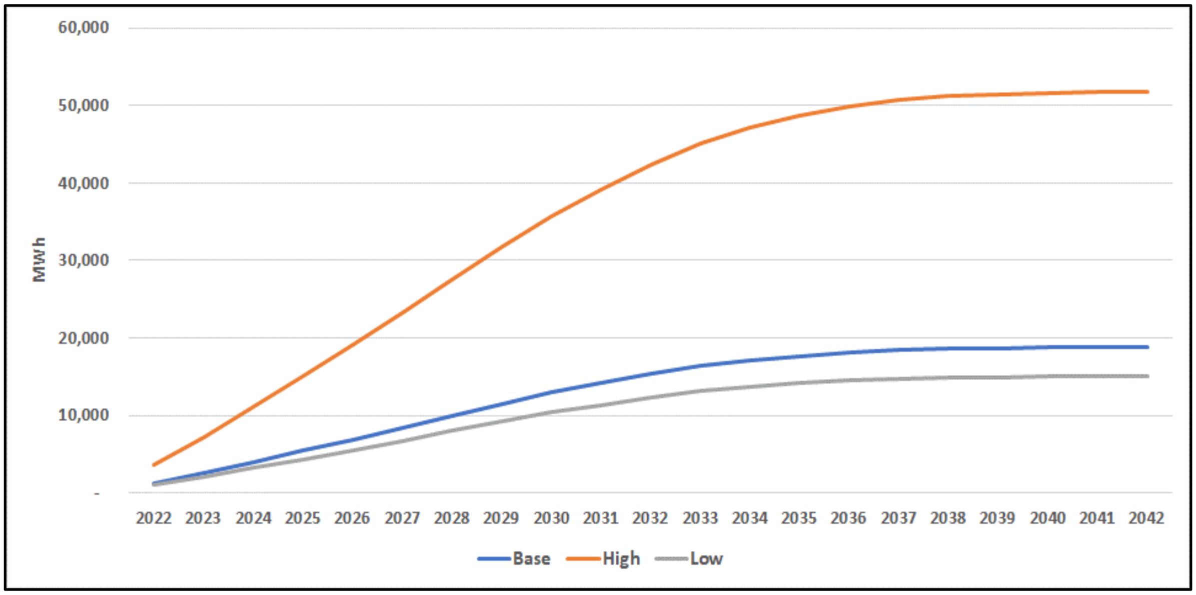


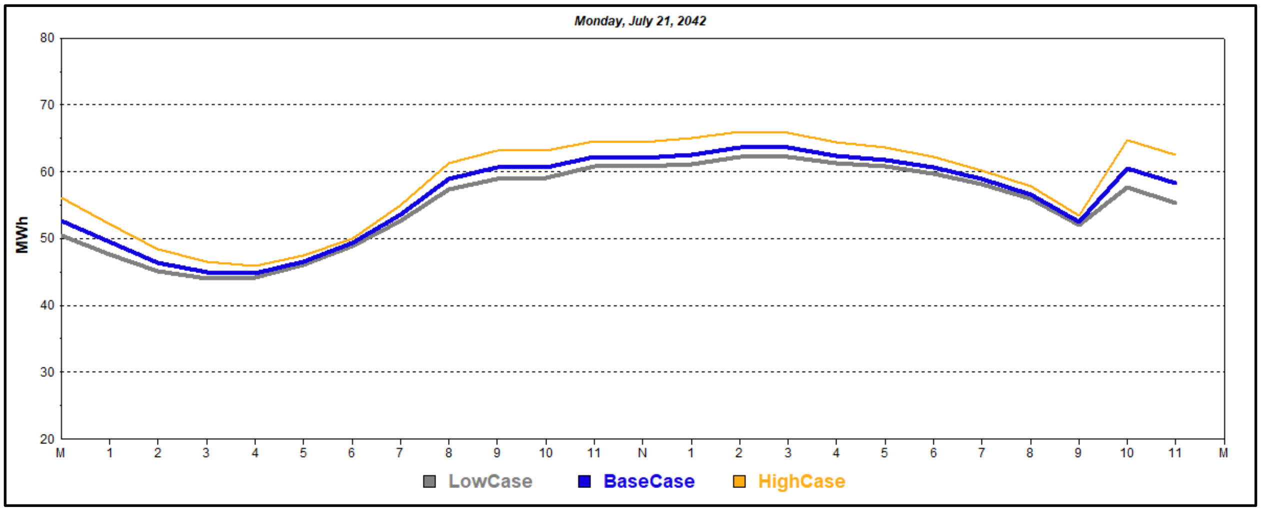
Table 14 shows resulting system energy forecasts.

TABLE 14: SCENARIO ENERGY FORECASTS (MWH)

Year	Low Case	Chg	BaseCase	Chg	High Case	Chg
2023	321,938		322,301		324,454	
2024	323,004	0.3%	324,222	0.6%	328,099	1.1%
2025	324,176	0.4%	325,867	0.5%	332,469	1.3%
2026	326,644	0.8%	328,816	0.9%	338,212	1.7%
2027	328,473	0.6%	331,134	0.7%	343,361	1.5%
2028	330,878	0.7%	334,092	0.9%	349,499	1.8%
2029	331,664	0.2%	335,438	0.4%	354,060	1.3%
2030	332,767	0.3%	337,064	0.5%	358,662	1.3%
2031	334,045	0.4%	338,898	0.5%	363,532	1.4%
2032	336,158	0.6%	341,543	0.8%	369,026	1.5%
2033	336,753	0.2%	342,644	0.3%	372,796	1.0%
2034	338,250	0.4%	344,701	0.6%	376,863	1.1%
2035	340,005	0.5%	346,979	0.7%	380,840	1.1%
2036	342,894	0.8%	350,364	1.0%	385,836	1.3%
2037	344,862	0.6%	352,962	0.7%	389,345	0.9%
2038	347,723	0.8%	356,410	1.0%	393,473	1.1%
2039	350,603	0.8%	359,869	1.0%	397,476	1.0%
2040	354,455	1.1%	364,415	1.3%	402,582	1.3%
2041	356,880	0.7%	367,528	0.9%	406,211	0.9%
2042	360,241	0.9%	371,573	1.1%	410,761	1.1%
23-42		**0.6%**		**0.8%**		**1.2%**

High and Low EV and heat pump energy forecasts are combined with EV and heat pump hourly load profiles generating High and Low EV and heat pump hourly load forecasts. The baseline hourly load forecast is then adjusted by adding the High and Low technology scenarios. Figure 34 compares the summer peak day load for the three scenarios.

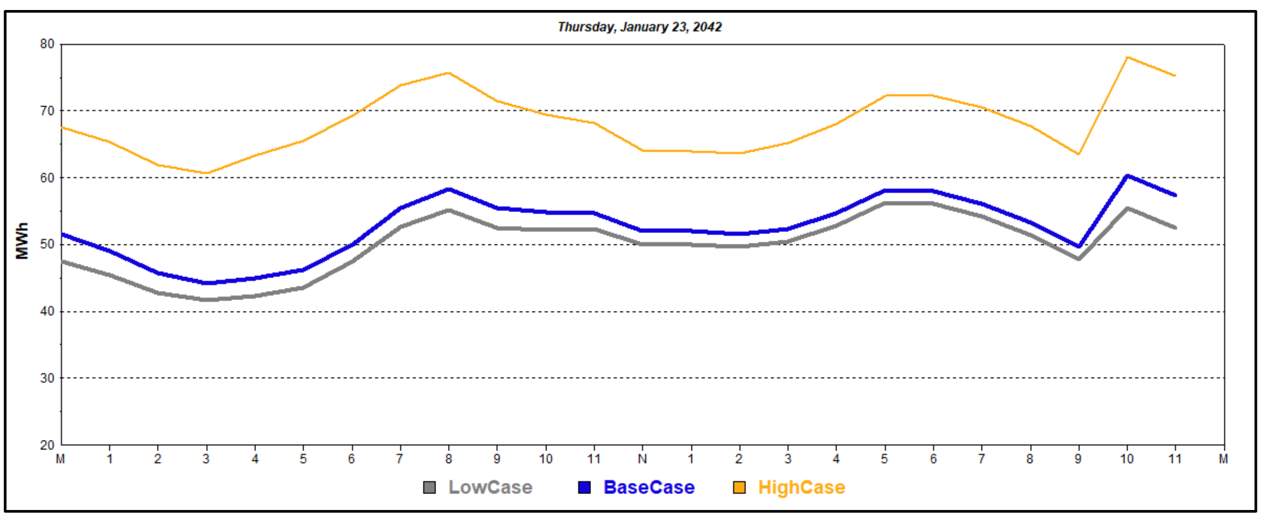
FIGURE 34: SUMMER PEAK DAY 2042



In the High scenario the peak shifts out to 11:00 P.M driven primarily by electric charging load. Work and public EV charging and additional heat pump cooling adds load through the day-time hours.

Figure 35 show the 2042 winter peak day.

FIGURE 35: WINTER PEAK DAY 2042



Given the projected heat pump adoption, the High case winter peak day load is significantly higher across all the hours. By 2032, the system also switches from summer peaking to winter peaking.

Monthly peaks are derived from the hourly load forecasts. Table 15 compares the summer peaks and Table 16 compares the winter peaks.

TABLE 15: SUMMER PEAK SCENARIO COMPARISON (MW)

Year	Low Case	Chg	BaseCase	Chg	High Case	Chg
2023	61.8		61.9		62.1	
2024	62.2	0.6%	62.4	0.8%	62.7	1.0%
2025	62.4	0.3%	62.7	0.5%	63.2	0.8%
2026	62.7	0.5%	63.2	0.8%	63.9	1.1%
2027	63.1	0.6%	63.6	0.6%	64.5	0.9%
2028	63.5	0.6%	64.2	0.9%	65.3	1.2%
2029	64.0	0.8%	64.7	0.8%	66.1	1.2%
2030	64.2	0.3%	65.1	0.6%	66.7	0.9%
2031	64.5	0.5%	65.4	0.5%	67.2	0.7%
2032	64.7	0.3%	65.8	0.6%	67.8	0.9%
2033	64.9	0.3%	66.1	0.5%	68.3	0.7%
2034	65.1	0.3%	66.3	0.3%	68.7	0.6%
2035	65.6	0.8%	66.9	0.9%	69.4	1.0%
2036	66.0	0.6%	67.3	0.6%	69.9	0.7%
2037	66.1	0.2%	67.5	0.3%	70.1	0.3%
2038	66.5	0.6%	67.9	0.6%	70.6	0.7%
2039	66.9	0.6%	68.4	0.7%	71.1	0.7%
2040	67.3	0.6%	68.8	0.6%	71.6	0.7%
2041	67.9	0.9%	69.5	1.0%	72.4	1.1%
2042	68.2	0.4%	69.9	0.6%	72.9	0.7%
23-42		**0.5%**		**0.6%**		**0.8%**

TABLE 16: WINTER PEAK SCENARIO COMPARISON (MW)

Year	Low Case	Chg	BaseCase	Chg	High Case	Chg
2023	51.4		51.5		52.6	
2024	51.8	0.8%	52.1	1.2%	54.3	3.2%
2025	52.3	1.0%	52.7	1.2%	56.1	3.3%
2026	52.9	1.1%	53.5	1.5%	58.0	3.4%
2027	53.4	0.9%	54.1	1.1%	59.9	3.3%
2028	54.0	1.1%	54.9	1.5%	61.9	3.3%
2029	54.4	0.7%	55.4	0.9%	63.8	3.1%
2030	54.8	0.7%	56.0	1.1%	65.6	2.8%
2031	55.2	0.7%	56.5	0.9%	67.2	2.4%
2032	55.5	0.5%	56.9	0.7%	68.6	2.1%
2033	55.8	0.5%	57.3	0.7%	69.9	1.9%
2034	56.0	0.4%	57.6	0.5%	70.9	1.4%
2035	56.1	0.2%	57.8	0.3%	71.6	1.0%
2036	56.4	0.5%	58.1	0.5%	72.3	1.0%
2037	56.5	0.2%	58.3	0.3%	73.5	1.7%
2038	56.7	0.4%	58.5	0.3%	74.4	1.2%
2039	56.8	0.2%	58.7	0.3%	75.0	0.8%
2040	57.0	0.4%	58.8	0.2%	76.0	1.3%
2041	57.0	0.0%	59.5	1.2%	77.5	2.0%
2042	57.1	0.2%	61.2	2.9%	79.4	2.5%
23-42		**0.6%**		**0.9%**		**2.2%**

4 FORECAST DATA AND ASSUMPTIONS

4.1 HISTORICAL CLASS SALES AND ENERGY DATA

Sales forecasts are based on linear regression models estimated for residential, commercial, and street lighting customer classes. Models are estimated using historical monthly billing data that includes sales, customers, and revenue. Sales loss as a result of solar adoption are added back to residential and commercial sales. The estimation period includes January 2012 to October 2022.

System monthly energy and monthly peak demands are derived from historical system hourly load data with solar load added back in (reconstituted). Models are estimated over the period January 2012 to October 2022. System energy is forecast is derived by applying average monthly loss factors to the sales forecasts. Monthly system peak demand is estimated using linear regression model.

4.2 WEATHER DATA

4.2.1 Monthly Heating and Cooling Degree-Days

Heating Degree-Days (HDD) and Cooling Degree-Days (CDD) are used to capture monthly variation due to weather; HDD captures heating loads and CDD cooling loads. CDD and HDD are constructed from daily average temperatures from the Burlington International Airport (BTV).

HDD and CDD are what are called spline variables as they take on a positive value when temperature criteria is met and if not are 0. HDD are positive when temperatures are below a temperature breakpoint, and 0 when temperatures are equal or higher than the breakpoint. CDD are the opposite; CDD are positive when temperatures are above the temperature breakpoint and are 0 when temperatures are at or below the temperature breakpoint. Published HDD and CDD are based on a 65 degree temperature breakpoint:

If temperature <65, HDD = 65 – temperature, otherwise HDD = 0
If temperature>65, CDD = temperature – 65, otherwise CDD = 0

While HDD and CDD with a 65 degree temperature breakpoint work well in modeling monthly sales, sales models can usually be improved by constructing HDD and CDD with different temperature breakpoints. This is illustrated in Figure 36 and Figure 37.

Figure 36 shows the residential relationship between daily residential use and daily average temperature and Figure 37 shows the commercial relationship.

FIGURE 36: RESIDENTIAL LOAD/TEMPERATURE RELATIONSHIP

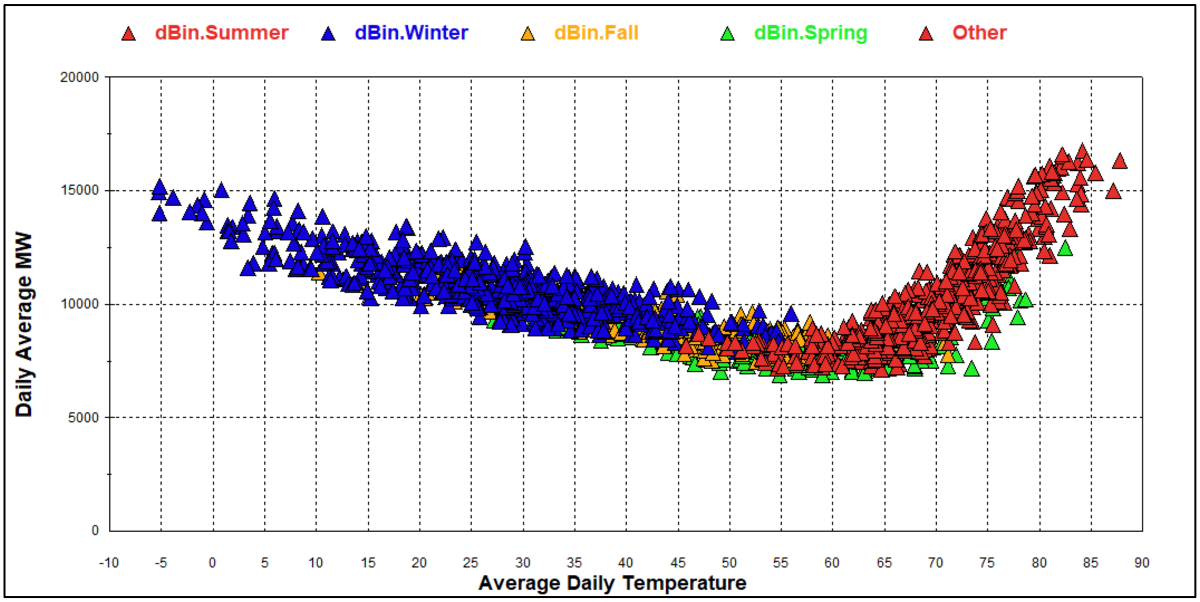
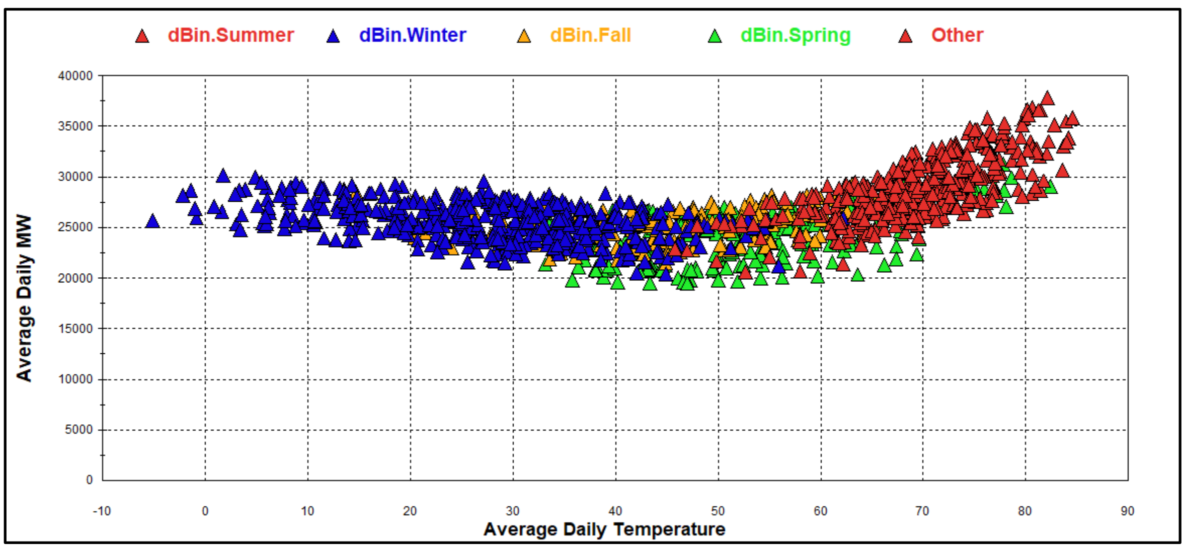


FIGURE 37: COMMERCIAL LOAD/TEMPERATURE RELATIONSHIP

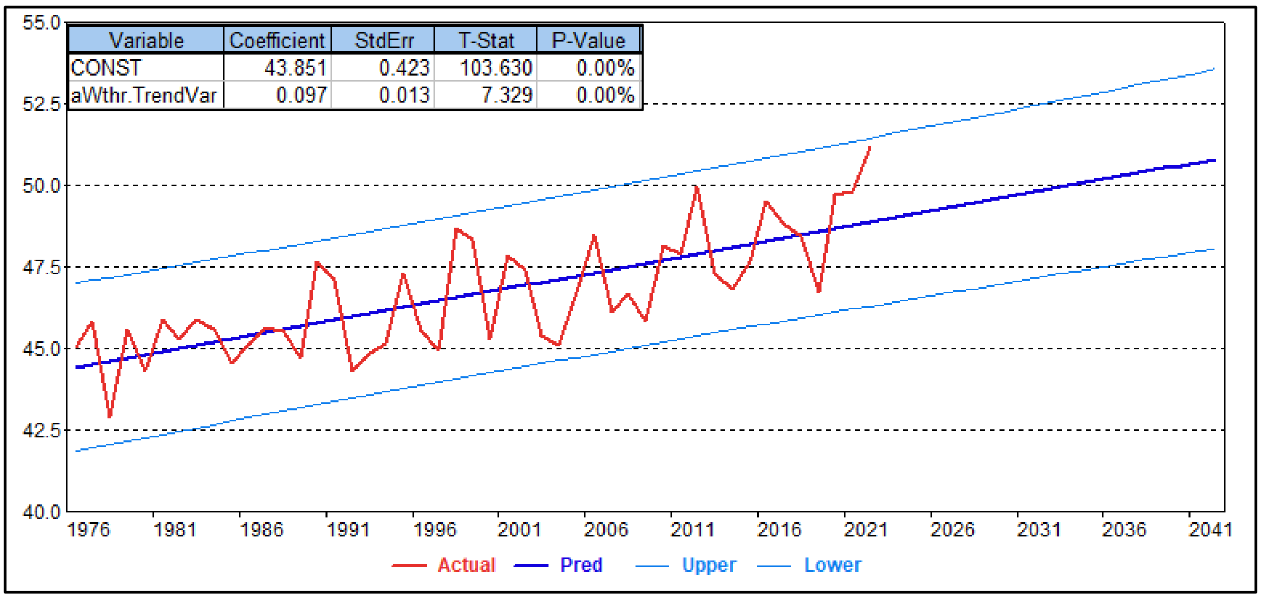


In the residential class we can see that heating is starting at a lower temperature; the best model fit was with HDD that began at 60 degrees and CDD at 65 degrees; generally, there is little heating until average daily temperature falls below 60 degrees. The commercial model can be improved with CDD that start at 55 degrees and HDD with a temperature base of 50 degrees. Commercial cooling starts at a much lower temperature point as cooling to account for internal heat build-up and heating starts at a lower temperature point as internally generated heat from lighting, computers and office equipment helps heat the building interior. The scatter plot also shows that commercial sector load is not particularly sensitive to changes in cold-side temperatures; this is partly because most commercial (and residential) customers heat with natural gas.

Monthly HDD and CDD are calculated by first calculating daily degree-days for each defined temperature breakpoint and then summed over the month.

Normal HDD and CDD. Expected HDD and CDD are key forecast model variables. Traditionally, forecasts are based on "normal" HDD and CDD. Where normal degree-days are defined as the average of past daily or monthly degree-days. Typically, the average is over a 20 or 30 year historical time period. What has become clear in recent years is that this is not necessarily the best assumption; data indicates that average temperatures are increasing resulting in more CDD and fewer HDD. Figure 38 shows a simple model where average annual temperature from BTV is regressed on a time.

FIGURE 38: AVERAGE TEMPERATURE TREND (BVT)



The red line shows actual annual average temperatures. The dark blue line is the fitted trendline and the light blue line shows the 95% confidence interval. The T Statistic on Trend is 7.329 indicating that there is a strong positive increasing temperature trend. The estimated coefficient indicates that over the period 1976 to current, the average annual temperature has been increasing 0.1 degrees per year or 1.0 degrees per decade; this is consistent with other regions we have evaluated. In 1976 the expected average temperature was 44.4 degrees in 2022 the expected average temperature is 48.9 degrees. Climate models indicate that we can expect temperatures to continue to increase.

Rather than assuming HDD and CDD are constant over the forecast period, we assume HDD and CDD will continue to increase over time based on historical degree-day trends. Degree-day trends are calculated based on the increase in the 20-year average. Figure 39 and Figure 40 show the actual annual degree-days in blue and the twenty-year normal trend in red.

FIGURE 39: HDD TREND (BASE 65 DEGREES)

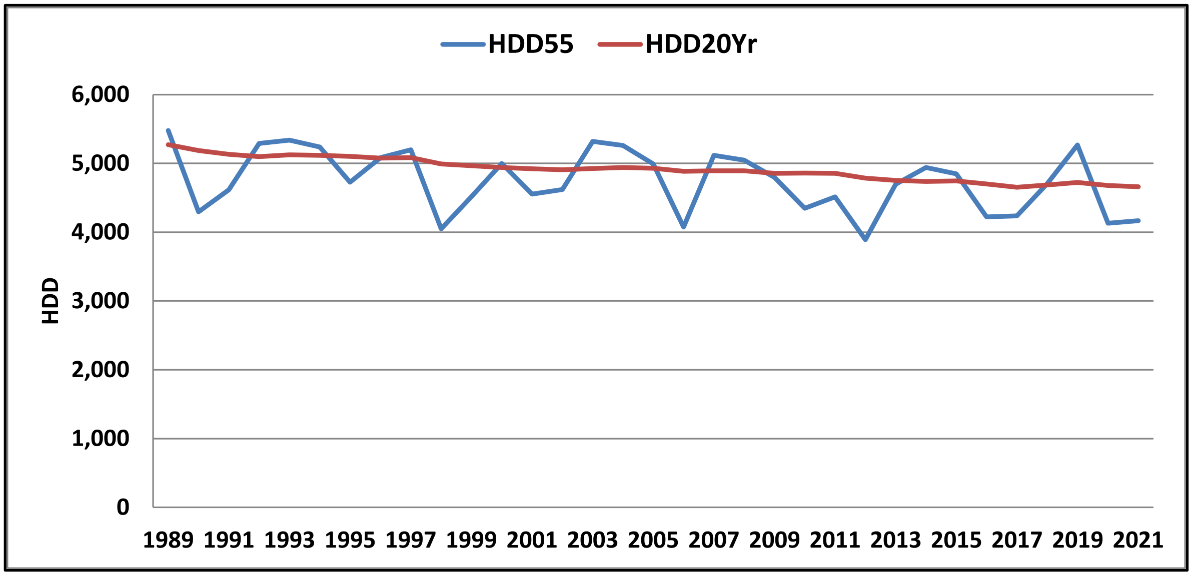
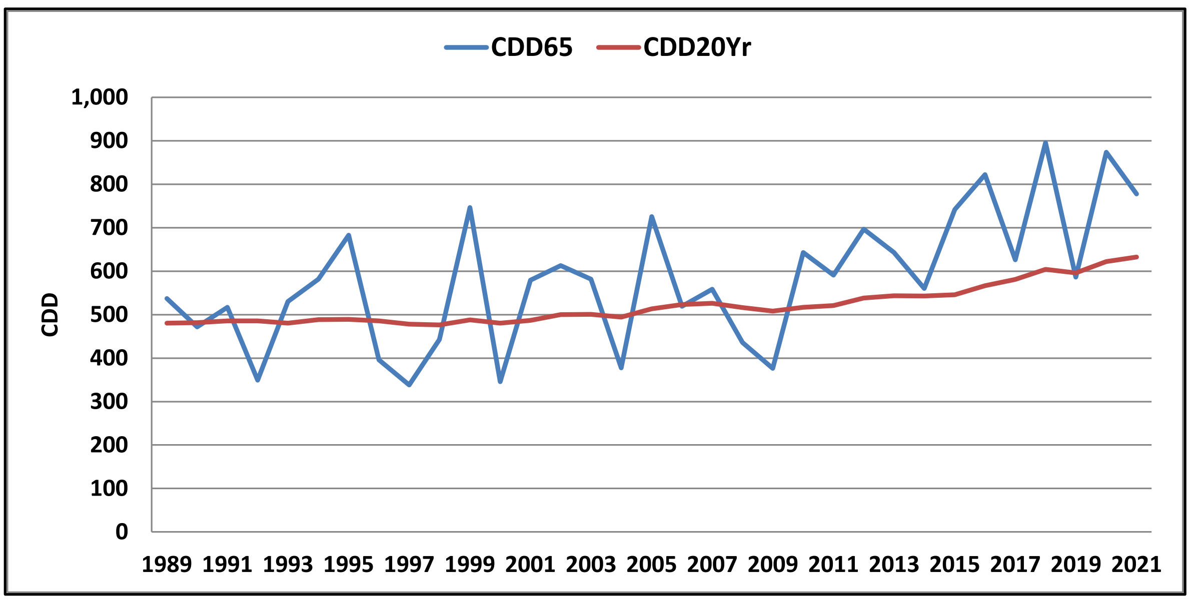


FIGURE 40: CDD TREND (BASE 65 DEGREES)



Both HDD and CDD show visible trends consistent with the average annual temperature trend. The 20-year normal CDD has been increasing on average 1.3% per year and HDD have been declining 0.3% per year. Since 2010, CDD have been increasing faster than even the 20-year trend. The calculated trend rates are applied to starting 2012 20-year normal HDD and CDD; 2012 is the mid-point of the last twenty-year normal period. Figure 41 and Figure 42 show resulting trended degree days against actual degree-days.

FIGURE 41: ACTUAL AND EXPECTED CDD (BASE 65 DEGREES)

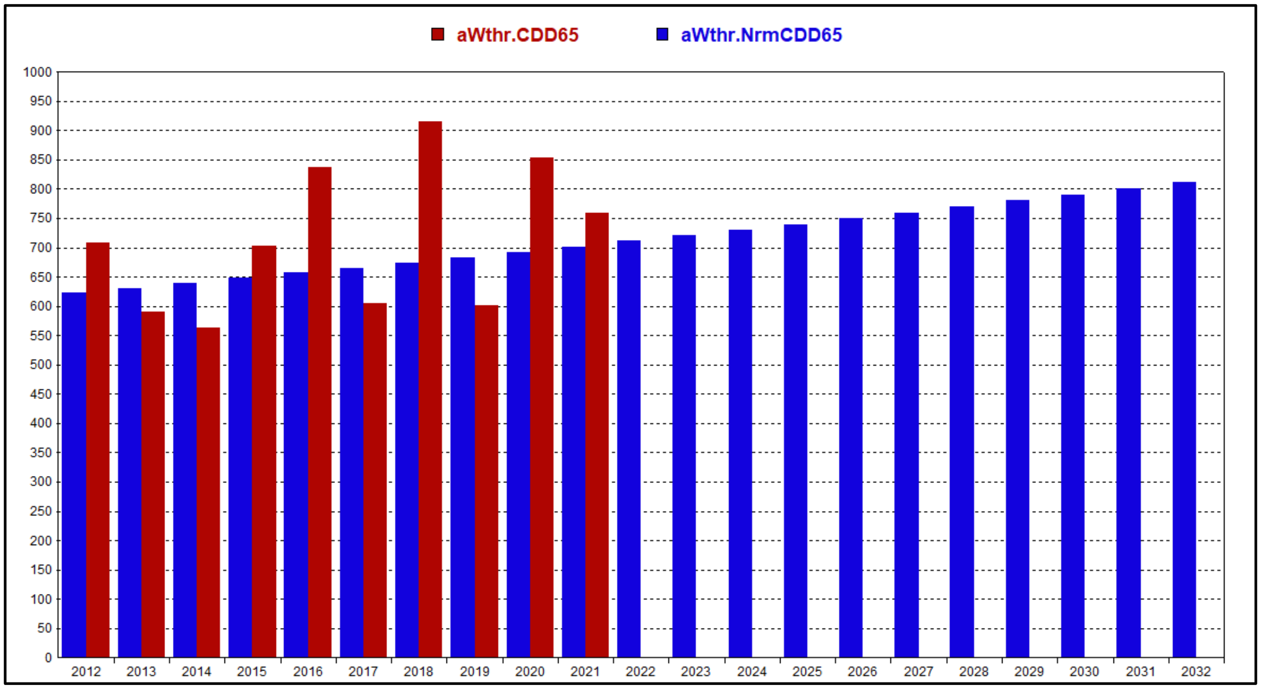
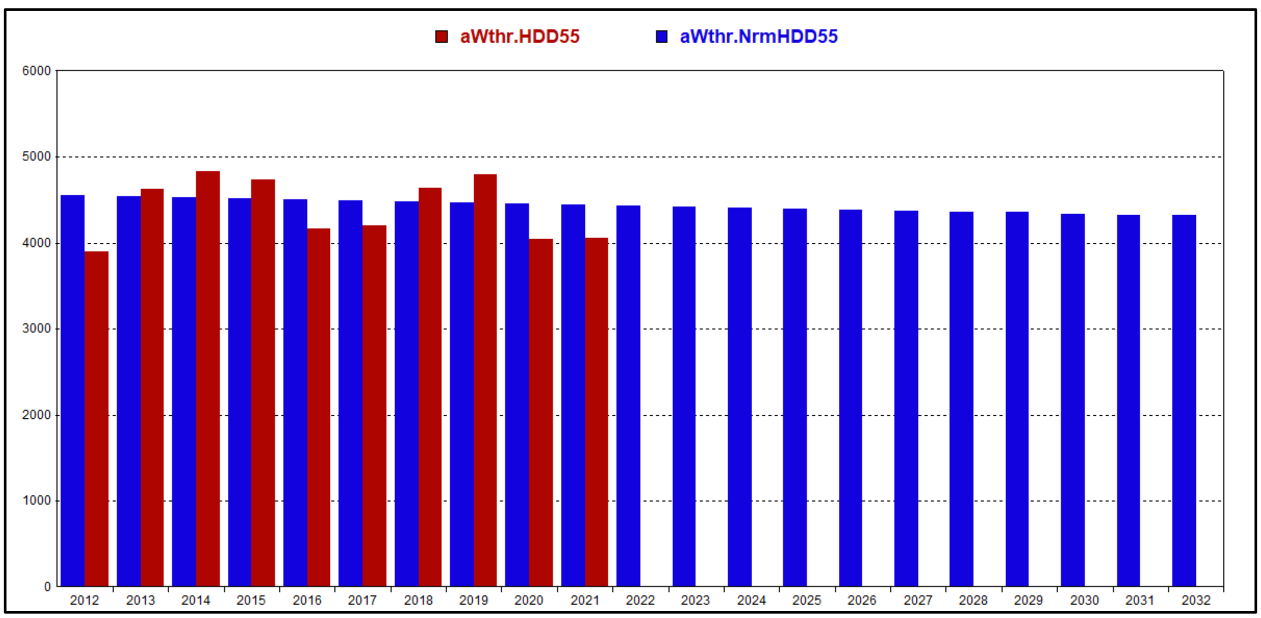


FIGURE 42: ACTUAL AND EXPECTED HDD (BASE 55 DEGREES)

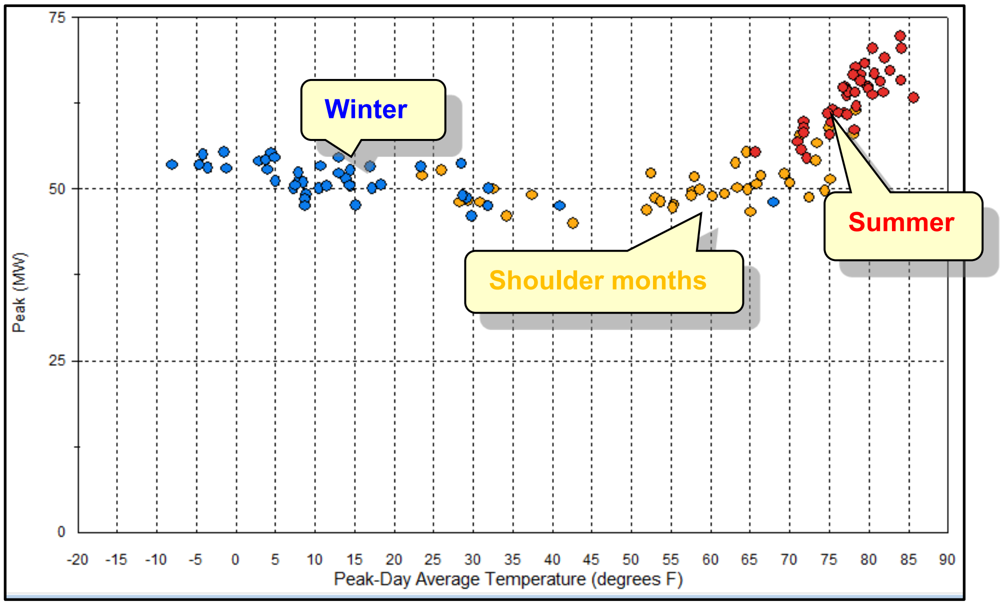


Expected increase in CDD contribute to stronger cooling requirements while declining HDD result in lower heating requirements.

4.2.2 Peak-Day Weather Variables

The peak forecast is based on a monthly peak regression model where peak-day HDD (PkHDD) and CDD (PkCDD) are important model inputs. PkCDD and PkHDD are also derived from historical daily average weather data for BTV. PkHDD and PkCDD are calculated by first finding the peak day in each month and associated average temperature. The average peak-day temperature is then used to construct PkHDD and PkCDD. The best temperature breakpoints appropriate breakpoints for defining PkHDD and PkCDD are determined by evaluating the relationship between monthly peak and the peak-day average temperature. Figure 43 shows this relationsip.

FIGURE 43: MONTHLY PEAK DEMAND /TEMPERATURE RELATIONSHIP



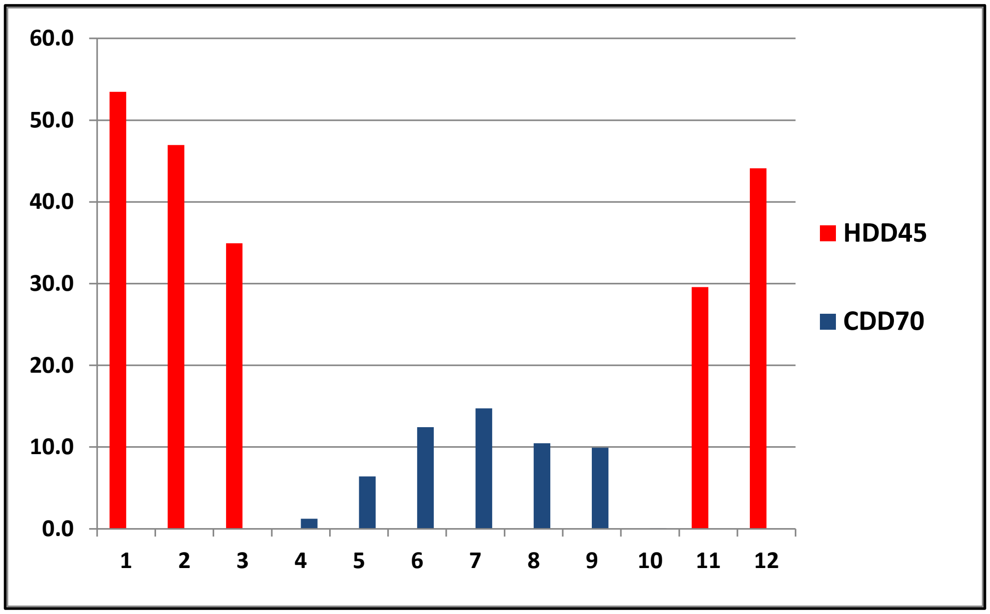
On the cold side, peaks do not occur until the average temperature is below 45 degrees and summer peaks occur when average daily temperature exceeds 70 degrees. PkHDD is calculated using a 45 degree base and PkCDD using a 70 degree base.

Normal Peak-Day Degree-Days. Normal PkHDD is based on the coldest days in each month and PkCDD is based on the hottest days in each month. The process for calculating peak-day normal degrees is outlined below:

1. Calculate daily HDD and CDD over the twenty-year period (2002 to 2021).
2. Find the highest HDD and CDD that occur in each month. This results in twelve monthly PkHDD and twelve monthly PkCDD for each year.
3. *Rank* the monthly PkHDD and PkCDD in each year from the highest value to the lowest value.
4. *Average* across the annual rankings – average the highest PkHDD values in each year, average the second highest in each year, the third highest …., average the lowest PkHDD values in each year. This results in twelve PkHDD values and twelve PkCDD values.

5. Assign PkHDD and PkCDD values to specific months based on past weather patterns. The highest PkHDD is assigned to January and the highest PkCDD value is assigned to July. Figure 44 shows the calculated peak-day normal PkHDD (base 45 degrees) and PkCDD (bases 70 degrees).

FIGURE 44: PEAK-DAY NORMAL WEATHER



PkHDD and PkCDD reflect the average peak producing weather over the prior twenty year period. Peak-day degrees are not trended as impact of increasing temperatures is captured in the heating and cooling loads (derived from the sales models) that interact with peak-day degree days in the constructed peak model variables.

4.3 ECONOMIC DATA

The class sales forecasts are based on *Moody's Economy.com* November 2022 economic forecast for the Burlington MSA. The primary economic drivers in the residential model include household income and the number of new households. Commercial sales are driven by regional output and employment. Table 17 shows the economic drivers.

TABLE 17: ECONOMIC FORECAST (BURLINGTON MSA)

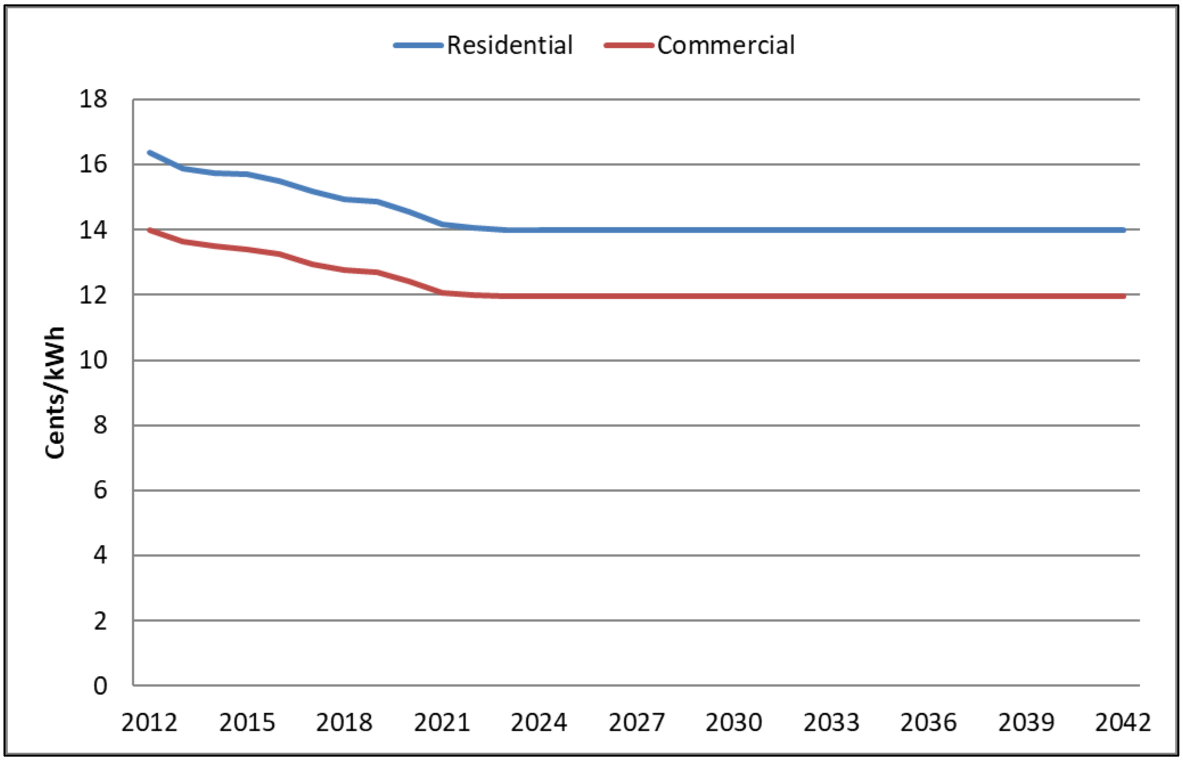
Year	HHs (thou)	% Chg	HHInc ($ thou)	% Chg	GDP ($ mil)	% Chg	Emp (thou)	% Chg
2012	85.6		121.5		12,027		120.2	
2013	86.5	1.1%	121.4	-0.1%	11,544	-4.0%	121.4	1.0%
2014	87.4	1.0%	124.5	2.5%	11,624	0.7%	122.8	1.2%
2015	88.2	0.8%	126.5	1.6%	11,800	1.5%	125.1	1.9%
2016	88.6	0.5%	127.7	1.0%	12,061	2.2%	125.8	0.6%
2017	89.3	0.7%	128.4	0.5%	12,198	1.1%	126.5	0.6%
2018	89.5	0.2%	129.6	1.0%	12,272	0.6%	127.1	0.5%
2019	89.7	0.3%	134.7	3.9%	12,477	1.7%	127.7	0.5%
2020	89.5	-0.3%	141.5	5.0%	12,353	-1.0%	117.2	-8.2%
2021	89.8	0.4%	143.6	1.5%	13,040	5.6%	118.9	1.5%
2022	90.3	0.5%	139.2	-3.1%	13,295	2.0%	121.2	1.9%
2023	90.6	0.4%	140.6	1.0%	13,446	1.1%	122.6	1.2%
2024	90.8	0.2%	143.4	2.0%	13,690	1.8%	123.3	0.6%
2025	91.1	0.3%	146.0	1.8%	13,997	2.2%	124.1	0.6%
2026	91.4	0.3%	149.1	2.1%	14,335	2.4%	125.0	0.7%
2027	91.6	0.2%	152.0	1.9%	14,672	2.3%	125.9	0.7%
2028	91.8	0.2%	154.6	1.7%	15,000	2.2%	126.7	0.6%
2029	92.0	0.2%	157.2	1.7%	15,313	2.1%	127.5	0.6%
2030	92.2	0.2%	159.6	1.5%	15,599	1.9%	128.2	0.5%
2031	92.4	0.2%	161.8	1.4%	15,869	1.7%	128.9	0.5%
2032	92.6	0.2%	163.9	1.3%	16,134	1.7%	129.6	0.5%
2033	92.7	0.2%	166.0	1.3%	16,404	1.7%	130.2	0.5%
2034	92.9	0.2%	168.0	1.2%	16,671	1.6%	130.8	0.5%
2035	93.1	0.2%	170.0	1.2%	16,929	1.5%	131.4	0.5%
2036	93.3	0.2%	171.9	1.1%	17,181	1.5%	132.0	0.5%
2037	93.5	0.2%	173.9	1.1%	17,428	1.4%	132.6	0.5%
2038	93.6	0.2%	175.8	1.1%	17,666	1.4%	133.1	0.4%
2039	93.8	0.2%	177.5	1.0%	17,900	1.3%	133.7	0.5%
2040	94.0	0.2%	179.1	0.9%	18,130	1.3%	134.2	0.4%
2041	94.2	0.2%	180.6	0.9%	18,357	1.2%	134.7	0.4%
2042	94.4	0.2%	182.2	0.9%	18,582	1.2%	135.2	0.4%
12-21		0.5%		1.4%		1.0%		0.1%
22-32		0.2%		1.6%		2.0%		0.7%
22-42		0.2%		1.4%		1.7%		0.5%

Burlington MSA is expected to see relatively strong economic growth, with the region adding 200 to 300 new households per year with moderate GDP growth averaging 1.7% over the forecast period.

4.4 PRICE DATA

Historical prices (real dollars) are provided by BED. Prices impact the class sales through imposed price elasticities. The residential and commercial price elasticities are set at -0.10. Over the long-term, we assume constant real prices. Figure 45 shows price forecasts by customer class.

FIGURE 45: HISTORICAL AND PROJECTED REAL PRICES (CENTS PER KWH)

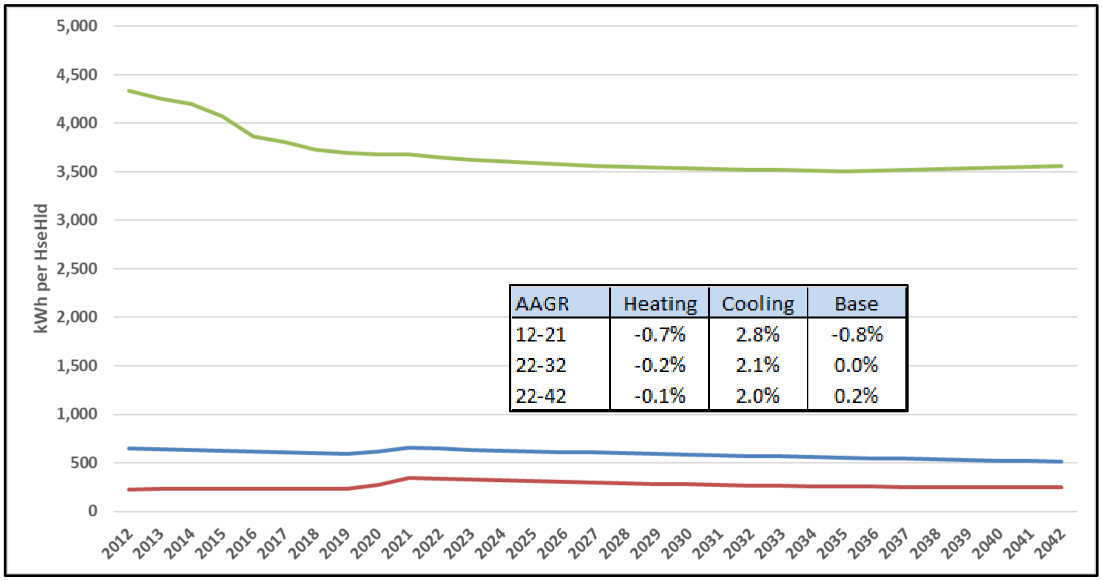


4.5 APPLIANCE SATURATION AND EFFICIENCY TRENDS

Average use in both residential and commercial sector have been declining over the last ten years. The primary contributor has been significant efficiency improvements in residential appliances and thermal shell and business end-uses. Efficiency improvements are a result of appliance standards, building codes, and BED energy efficiency programs. Efficiency impacts are captured through historical and projected end-use intensities. In the residential sector intensities are measured in kWh per household and in the commercial sector intensities are in kWh per square foot. Starting end-use intensities are derived from the Energy Information Administration's (EIA) 2022 New England Census Division forecast. Saturation projections are adjusted to reflect BED residential appliance saturation surveys and mix of multi-family and single-family homes. Efficiency projections are adjusted to account for BED program efficiency savings that are not reflected in the EIA's regional forecast. The residential sector includes saturation and efficiency trends for seventeen end-uses, and the commercial sector has end-use intensity projections for ten end-uses across ten building types.

For modeling residential average use and commercial sales, end-use intensities are aggregated into three generalized end-uses: heating, cooling, and base use. Figure 46 shows the primary end-use intensity projections for the residential customer class.

FIGURE 46: RESIDENTIAL END-USE ENERGY INTENSITIES

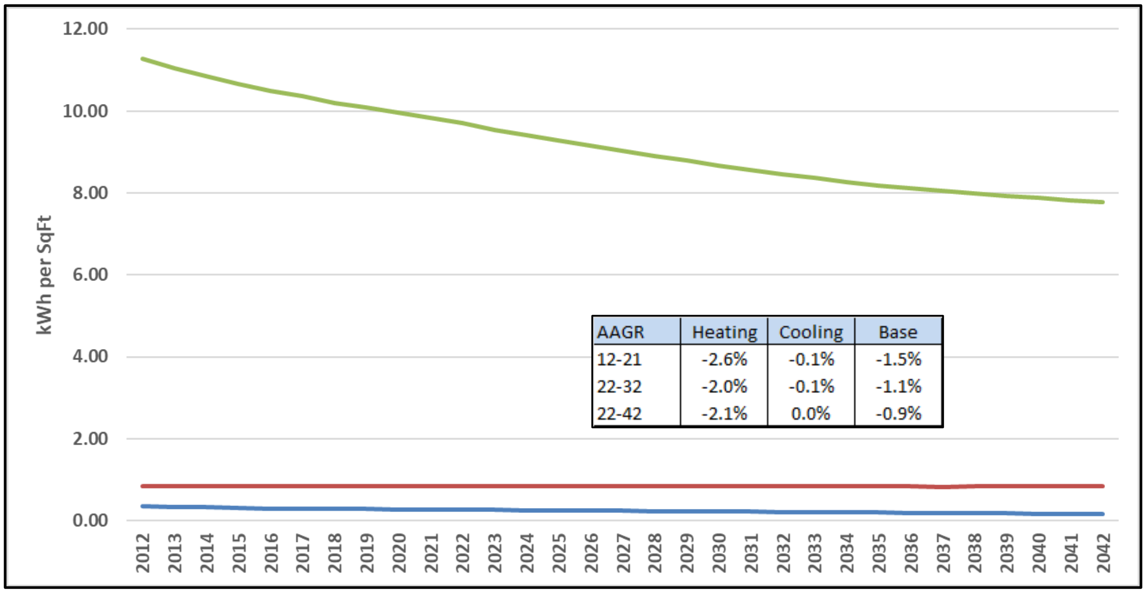


* Incorporates impact of BED Funded EE Programs

As the figure illustrates, heating and cooling intensities are relatively small. Summer temperatures are comparatively mild and natural gas is the primary heating fuel. Most of the heating load is furnace fans and backup resistant heat. Heating intensity declines 0.1% annually through the forecast period reflecting continuing improvements in heating technology (improvements in heat pump and furnace fan efficiency), substitution of resistance heat for heat pumps, and declining overall resistant heat saturation. Though small, cooling intensity is expected to increase. Through 2021, BED experienced strong growth in cooling intensity averaging 2.8% annual growth. This increase was largely driven by room air conditioning saturation growth. Cooling intensity flattens-out over the forecast period as room air conditioning saturation growth slows. Non-weather sensitive end-use intensity continues to decline through 2036 as a result of new appliance standards and natural replacement of existing equipment stock, and EE program activity. Other Use (Base) intensities turn slightly positive after 2036 as miscellaneous use continues to increase faster than efficiency gains across the other end-uses. Intensity projections do not include the expected impact of program related heat pump adoption.

Commercial end-use intensities (expressed in kWh per square foot) are adjusted to reflect BED commercial building-mix. As in the residential sector, there have been significant improvements in end-use intensities as a result of new standards and EE programs. Figure 47 shows commercial end-use energy intensity forecasts for the aggregated end-use categories.

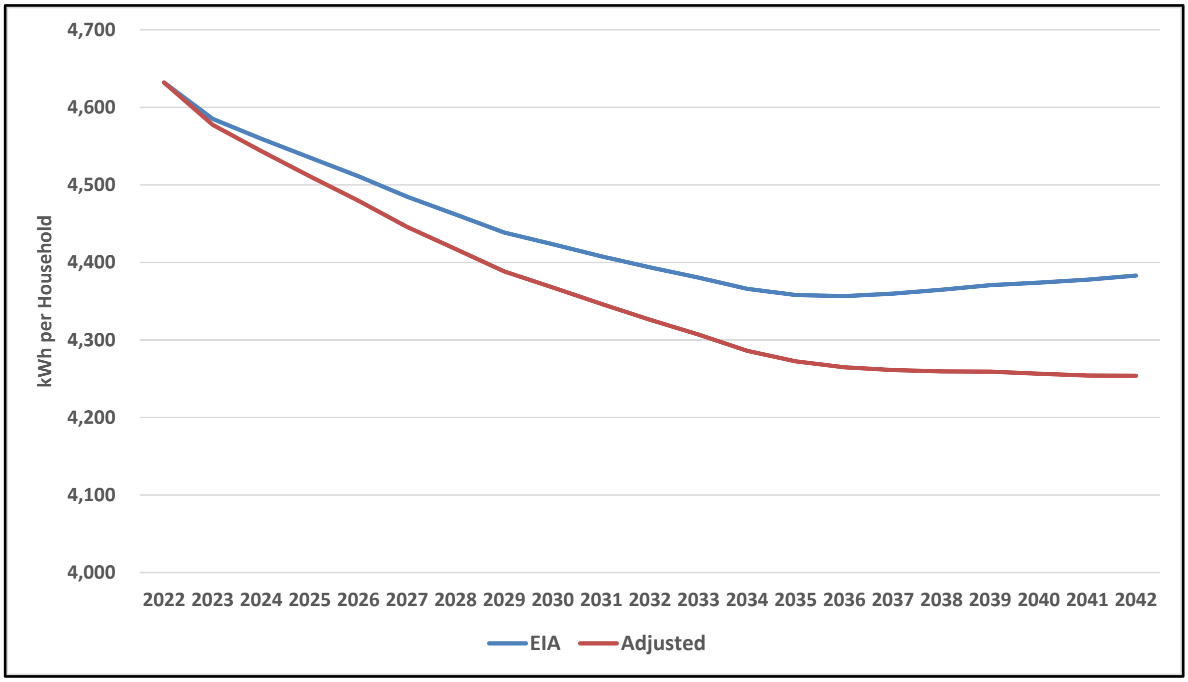
FIGURE 47: COMMERCIAL END-USE ENERGY INTENSITY



Given temperate summers and low saturation of electric heat, commercial heating and cooling intensities are relatively small. The decline in intensities is the result of improving commercial equipment efficiency and EE program impacts. Strong declines in lighting and ventilation intensities have the largest impact on non-weather sensitive use.

Adjusting for EE Savings. In addition to codes and standards, EIA's efficiency projections reflect expected impacts of New England EE program activity. Our models indicate that most of BED program savings (around 80%) have been captured by EIA's intensity trends. To avoid double-counting EE savings, the intensity trends are adjusted down for the share of savings (20%) that are not already embedded in the EE intensity projections. Figure 48 EIA total intensity projection with the BED adjusted intensity forecast.

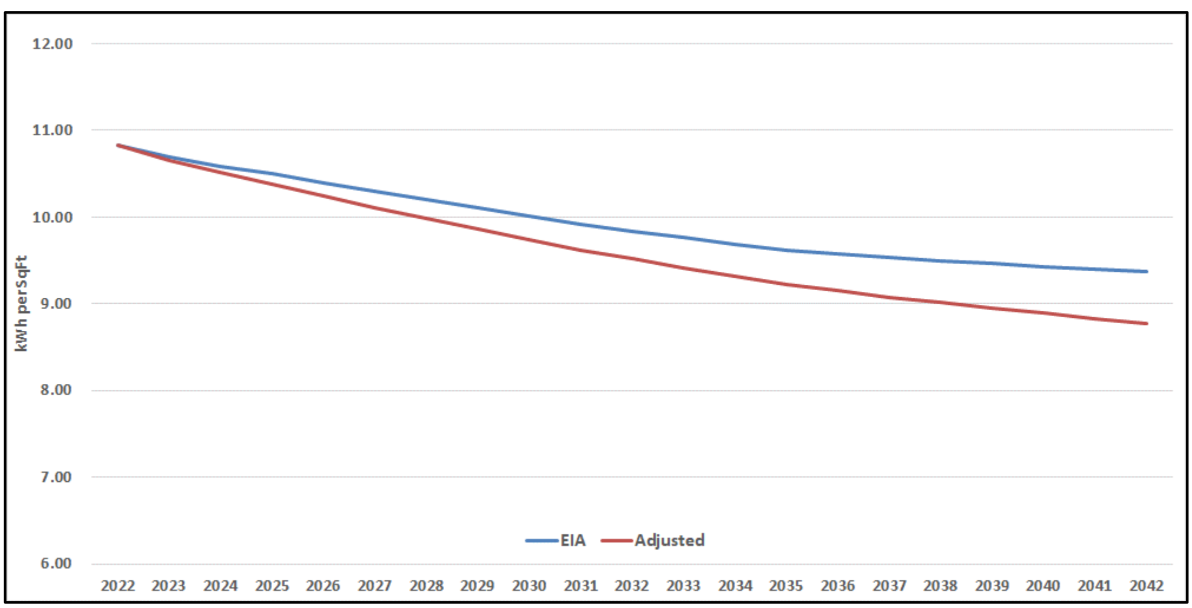
FIGURE 48: RESIDENTIAL TOTAL INTENSITY COMPARISON



EIA total residential intensity declines 0.4% per year through 2036 before turning positive. BED adjusted intensity declines 0.6% over this period and continues to decline 0.1% per year after 2036. By 2032, the adjusted residential intensity is 2% lower than EIA and 3% lower by 2042.

Figure 49 shows the commercial adjusted intensity.

FIGURE 49: COMMERCIAL INTENSITY TRENDS



Projected commercial intensity decline is stronger than residential as there is strong expected efficiency gains in commercial lighting and ventilation. EIA projects overall commercial intensity to decline 0.7% per year over the forecast period. Adjusted for EE savings commercial intensity declines on average 1.0% per year.

The adjusted intensities are incorporated into the constructed SAE model variables.

APPENDIX A

Residential Average Use Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructRes.XHeat	0.711	0.052	13.649	0.00%
mStructRes.XCool	1.14	0.051	22.176	0.00%
mStructRes.XOther	1.131	0.016	72.926	0.00%
mCovidVar.ResIndex	33.324	4.444	7.499	0.00%
mBin.Mar	-27.944	3.949	-7.076	0.00%
mBin.Apr	-51.899	5.35	-9.701	0.00%
mBin.May	-62.194	5.906	-10.53	0.00%
mBin.Jun	-45.97	4.561	-10.08	0.00%
mBin.Sep	-13.597	4.612	-2.948	0.39%
mBin.Oct	-33.931	5.782	-5.869	0.00%
mBin.Nov	-24.081	3.928	-6.13	0.00%
mBin.May13	25.277	8.752	2.888	0.46%
MA(1)	0.694	0.071	9.767	0.00%

Model Statistics	
Iterations	29
Adjusted Observations	130
Deg. of Freedom for Error	117
R-Squared	0.96
Adjusted R-Squared	0.956
AIC	4.983
BIC	5.269
Log-Likelihood	-495.33
Model Sum of Squares	371,926.83
Sum of Squared Errors	15,523.88
Mean Squared Error	132.68
Std. Error of Regression	11.52
Mean Abs. Dev. (MAD)	8.52
Mean Abs. % Err. (MAPE)	2.01%
Durbin-Watson Statistic	1.704

Residential Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	-16273.501	2749.556	-5.919	0.00%
Economics.HHs	373.673	30.784	12.138	0.00%
mBin.Jun	969.549	45.647	21.24	0.00%
mBin.Aug	178.449	42.351	4.214	0.01%
mBin.Sep	80.692	40.837	1.976	5.13%
MA(1)	0.342	0.116	2.957	0.40%
MA(2)	0.379	0.104	3.633	0.05%

Model Statistics	
Iterations	19
Adjusted Observations	94
Deg. of Freedom for Error	87
R-Squared	0.92
Adjusted R-Squared	0.914
AIC	9.6
BIC	9.789
Log-Likelihood	-577.57
Model Sum of Squares	13,747,615.82
Sum of Squared Errors	1,195,695.84
Mean Squared Error	13743.63
Std. Error of Regression	117.23
Mean Abs. Dev. (MAD)	83.49
Mean Abs. % Err. (MAPE)	0.48%
Durbin-Watson Statistic	1.795

Commercial Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructCom.XHeat	12251.401	2609.09	4.696	0.00%
mStructCom.XCool	21448.864	772.74	27.757	0.00%
mStructCom.XOther	1817.054	12.149	149.56	0.00%
ComLoadLoss.TotMWh	-0.748	0.186	-4.026	0.01%
mBin.Feb	501.33	138.136	3.629	0.04%
mBin.May	-746.283	152.522	-4.893	0.00%
mBin.Jun	-704.95	146.433	-4.814	0.00%
mBin.May12	-869.229	435.337	-1.997	4.81%
mBin.Jul13	1007.206	429.135	2.347	2.06%
MA(1)	0.361	0.094	3.859	0.02%

Model Statistics	
Iterations	13
Adjusted Observations	130
Deg. of Freedom for Error	120
R-Squared	0.955
Adjusted R-Squared	0.952
AIC	12.266
BIC	12.486
Log-Likelihood	-971.72
Model Sum of Squares	500,999,990.29
Sum of Squared Errors	23,657,444.05
Mean Squared Error	197145.37
Std. Error of Regression	444.01
Mean Abs. Dev. (MAD)	335.28
Mean Abs. % Err. (MAPE)	1.64%
Durbin-Watson Statistic	1.987

Commercial Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	1262.505	889.581	1.419	15.96%
ComCust.maResCust	0.155	0.052	2.986	0.37%
AR(1)	0.847	0.063	13.438	0.00%

Model Statistics	
Iterations	11
Adjusted Observations	88
Deg. of Freedom for Error	82
R-Squared	0.826
Adjusted R-Squared	0.815
AIC	6.734
BIC	6.903
Log-Likelihood	-415.15
Model Sum of Squares	306,382.49
Sum of Squared Errors	64,511.40
Mean Squared Error	786.72
Std. Error of Regression	28.05
Mean Abs. Dev. (MAD)	18.45
Mean Abs. % Err. (MAPE)	0.47%
Durbin-Watson Statistic	1.91

Other Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	0.999	0.072	13.924	0.00%
Seasonal	347.557	28685.097	0.012	99.00%

Model Statistics	
Iterations	52
Adjusted Observations	46
Deg. of Freedom for Error	44
R-Squared	1
Adjusted R-Squared	1
AIC	-0.788
BIC	-0.709
Log-Likelihood	-45.15
Model Sum of Squares	51,594.00
Sum of Squared Errors	19.00
Mean Squared Error	0.44
Std. Error of Regression	0.66
Mean Abs. Dev. (MAD)	0.35
Mean Abs. % Err. (MAPE)	0.19%
Durbin-Watson Statistic	1.584

Peak Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mCPkEndUses.BaseVar	1.585	0.016	96.213	0.00%
mWthr.HeatVar45	0.028	0.016	1.71	8.99%
mWthr.CoolVar70	0.94	0.053	17.667	0.00%
mBin.May	-3.651	0.642	-5.683	0.00%
mBin.Jul	6.366	0.696	9.151	0.00%
mBin.Aug	7.142	0.728	9.806	0.00%
mBin.Sep	4.485	0.731	6.135	0.00%
mBin.Oct	-2.463	0.768	-3.208	0.17%
mBin.Nov	-1.815	0.637	-2.849	0.52%
mBin.May12	9.18	1.925	4.769	0.00%
mBin.Apr20	-4.833	1.819	-2.657	0.90%
mBin.Sep21	-7.598	1.897	-4.005	0.01%
mBin.Jun22	-5.442	1.868	-2.913	0.43%
MA(1)	0.219	0.093	2.359	2.00%

Model Statistics	
Iterations	18
Adjusted Observations	130
Deg. of Freedom for Error	116
R-Squared	0.942
Adjusted R-Squared	0.936
AIC	1.308
BIC	1.617
Log-Likelihood	-255.5
Model Sum of Squares	6,346.56
Sum of Squared Errors	387.78
Mean Squared Error	3.34
Std. Error of Regression	1.83
Mean Abs. Dev. (MAD)	1.33
Mean Abs. % Err. (MAPE)	2.52%
Durbin-Watson Statistic	1.858

APPENDIX B
RESIDENTIAL SAE MODELING FRAMEWORK

The traditional approach 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, econometric models 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 drive energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency and saturation trends, dwelling square footage, and thermal shell integrity changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations, equipment efficiency, dwelling square footage, and thermal integrity levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be incorporated into the final model.

This section describes the SAE approach, the associated supporting SAE spreadsheets, and the *MetrixND* project files that are used in the implementation. The source for the SAE spreadsheets is the 2021 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

RESIDENTIAL STATISTICALLY ADJUSTED END-USE MODELING FRAMEWORK

The statistically adjusted end-use modeling framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$), and other equipment ($Other_{y,m}$). Formally,

$$USE_{y,m} = Heat_{y,m} + Cool_{y,m} + Other_{y,m} \tag{1}$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \tag{2}$$

$XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, dwelling data, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

Constructing XHeat

As represented in the SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days
- Heating equipment saturation levels
- Heating equipment operating efficiencies
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_{y,m} \times HeatUse_{y,m} \tag{3}$$

Where:

- $XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m)
- $HeatIndex_{y,m}$ is the monthly index of heating equipment
- $HeatUse_{y,m}$ is the monthly usage multiplier

The heating equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations (*Sat*), operating efficiencies (*Eff*), building structural index (*StructuralIndex*), and energy prices. Formally, the equipment index is defined as:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \middle/ Eff_y^{Type} \right)}{\left(Sat_{base\ yr}^{Type} \middle/ Eff_{base\ yr}^{Type} \right)} \tag{4}$$

The *StructuralIndex* is constructed by combining the EIA's building shell efficiency index trends with surface area estimates:

$$StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{base\ yr} \times SurfaceArea_{base\ yr}} \tag{5}$$

The *StructuralIndex* is defined on the *StructuralVars* tab of the SAE spreadsheets. Surface area is derived to account for roof and wall area of a standard dwelling based on the regional average square footage data obtained from EIA. The relationship between the square footage and surface area is constructed assuming an aspect ratio of 0.75 and an average of 25% two-story and 75% single-story. Given these assumptions, the approximate linear relationship for surface area is:

$$SurfaceArea_y = 892 + 1.44 \times Footage_y \tag{6}$$

For electric heating equipment, the SAE spreadsheets contain two equipment types: electric resistance furnaces/room units and electric space heating heat pumps. Examples of weights for these two equipment types for the U.S. are given in Table 18.

TABLE 18: ELECTRIC SPACE HEATING EQUIPMENT WEIGHTS

Equipment Type	Weight (kWh)
Electric Resistance Furnace/Room units	767
Electric Space Heating Heat Pump	127

Data for the equipment saturation and efficiency trends are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for electric space heating heat pumps is given in terms of Heating Seasonal Performance Factor [BTU/Wh], and the efficiencies for electric furnaces and room units are estimated as 100%, which is equivalent to 3.41 BTU/Wh.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, prices, and billing days. The estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{base\ yr}}\right) \times \left(\frac{HHSize_y}{HHSize_{base\ yr,m}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{base\ yr,m}}\right)^{0.15} \times \left(\frac{Elec\ Price_{y,m}}{Elec\ Price_{base\ yr,m}}\right)^{-0.1} \tag{7}$$

Where:

- *HDD* is the number of heating degree days in year (*y*) and month (*m*).
- *HHSize* is average household size in a year (*y*)
- *Income* is average real income per household in year (*y*)
- *ElecPrice* is the average real price of electricity in month (*m*) and year (*y*)

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to 1.0 in the base year. The first term, which involves heating degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will reflect changes in the economic drivers, as transformed through the end-use elasticity parameters. The price impacts captured by the Usage equation represent short-term price response.

Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days
- Cooling equipment saturation levels
- Cooling equipment operating efficiencies
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$XCool_{y,m} = CoolIndex_y \times CoolUse_{y,m} \tag{8}$$

Where

- $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m)
- $CoolIndex_y$ is an index of cooling equipment
- $CoolUse_{y,m}$ is the monthly usage multiplier

As with heating, the cooling equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Formally, the cooling equipment index is defined as:

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{base\,yr}^{Type} \big/ Eff_{base\,yr}^{Type} \right)} \tag{9}$$

For cooling equipment, the SAE spreadsheets contain three equipment types: central air conditioning, space cooling heat pump, and room air conditioning. Examples of weights for these three equipment types for the U.S. are given in Table 19.

TABLE 19: SPACE COOLING EQUIPMENT WEIGHTS

Equipment Type	Weight (kWh)
Central Air Conditioning	1,219
Space Cooling Heat Pump	240

Room Air Conditioning	177

The equipment saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for space cooling heat pumps and central air conditioning (A/C) units are given in terms of Seasonal Energy Efficiency Ratio [BTU/Wh], and room A/C units efficiencies are given in terms of Energy Efficiency Ratio [BTU/Wh].

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, and prices. The estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{CDD_{base\ yr}}\right) \times \left(\frac{HHSize_y}{HHSize_{base\ yr,m}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{base\ yr,m}}\right)^{0.15} \times \left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{base\ yr,m}}\right)^{-0.1} \qquad (10)$$

Where:

- *CDD* is the number of cooling degree days in year (*y*) and month (*m*).
- *HHSize* is average household size in a year (*y*)
- *Income* is average real income per household in year (*y*)
- *ElecPrice* is the average real price of electricity in month (*m*) and year (*y*)

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year. The first term, which involves cooling degree days, serves to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will change to reflect changes in the economic driver changes.

Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Appliance and equipment saturation levels
- Appliance efficiency levels
- Average number of days in the billing cycle for each month
- Average household size, real income, and real prices

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherEqpIndex_{y,m} \times OtherUse_{y,m} \qquad (11)$$

The first term on the right-hand side of this expression (*OtherEqpIndex*$_y$) embodies information about appliance saturation and efficiency levels and monthly usage multipliers. The second term (*OtherUse*) captures the impact of changes in prices, income, household size, and number of billing-days on appliance utilization.

End-use indices are constructed in the SAE models. A separate end-use index is constructed for each end-use equipment type using the following function form.

$$ApplianceIndex_{y,m} = Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ \frac{1}{UEC_y^{Type}} \right)}{\left(Sat_{base\ yr}^{Type} \Big/ \frac{1}{UEC_{base\ yr}^{Type}} \right)} \times MoMult_m^{Type} \times \quad (12)$$

Where:

- *Weight* is the weight for each appliance type
- *Sat* represents the fraction of households, who own an appliance type
- *MoMult*$_m$ is a monthly multiplier for the appliance type in month (*m*)
- *Eff* is the average operating efficiency the appliance
- *UEC* is the unit energy consumption for appliances

This index combines information about trends in saturation levels and efficiency levels for the main appliance categories with monthly multipliers for lighting, water heating, and refrigeration.

The appliance saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets.

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$ApplianceUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{HHSize_y}{HHSize_{base\ yr,m}}\right)^{0.26} \times \left(\frac{Income_y}{Income_{base\ yr,m}}\right)^{0.15} \times \left(\frac{Elec\ Price_{y,m}}{Elec\ Price_{base\ yr,m}}\right)^{-0.1} \quad (13)$$

The index for other uses is derived then by summing across the appliances:

$$OtherEqpIndex_{y,m} = \sum_k ApplianceIndex_{y,m} \times ApplianceUse_{y,m} \quad (14)$$

APPENDIX C
COMMERCIAL SAE MODELING FRAMEWORK

The traditional approach 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 identifying historical trends and to projecting 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 statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency trends and saturation changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations and equipment efficiency levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be built into the final model.

This document describes this approach, the associated supporting Commercial SAE spreadsheets, and *MetrixND* project files that are used in the implementation. The source for the commercial SAE spreadsheets is the 2021 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

COMMERCIAL STATISTICALLY ADJUSTED END-USE MODEL FRAMEWORK

The commercial statistically adjusted end-use model framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$) and other equipment ($Other_{y,m}$). Formally,

$$USE_{y,m} = Heat_{y,m} + Cool_{y,m} + Other_{y,m} \tag{1}$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \tag{2}$$

Here, $XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

Constructing XHeat

As represented in the Commercial SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days,
- Heating equipment saturation levels,
- Heating equipment operating efficiencies,
- Commercial output, employment, population, and energy price.

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$\mathrm{XHeat}_{y,m} = \mathrm{HeatIndex}_{y} \times \mathrm{HeatUse}_{y,m} \tag{3}$$

Where:

- *$XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m),*
- *$HeatInde_{xy}$ is the annual index of heating equipment, and*
- *$HeatUse_{y,m}$ is the monthly usage multiplier.*

The heating equipment index is composed of electric space heating equipment saturation levels normalized by operating efficiency levels. The index will change over time with changes in heating equipment saturations (*HeatShare*) and operating efficiencies (*Eff*). Formally, the equipment index is defined as:

$$HeatIndex_y = HeatSales_{base\ yr} \times \frac{\left(HeatShare_y / Eff_y\right)}{\left(HeatShare_{base\ yr} / Eff_{base\ yr}\right)} \tag{4}$$

The ratio on the right is equal to 1.0 in the base year. In other years, it will be greater than one if equipment saturation levels are above their base year level. This will be counteracted by higher efficiency levels, which will drive the index downward. Base year space heating sales are defined as follows.

$$HeatSales_{base\ yr} = \left(\frac{kWh}{Sqft}\right)_{Heating} \times \left(\frac{CommercialSales_{base\ yr}}{\sum_e kWh / Sqft_e}\right) \tag{5}$$

Here, base-year sales for space heating is the product of the average space heating intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space heating sales value is defined on the *BaseYrInput* tab. The resulting $HeatIndex_y$ value in the base year will be equal to the estimated annual heating sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, commercial level economic activity, prices and billing days. Using the COMMEND default elasticity parameters, the estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{base\ yr}}\right) \times \left(\frac{EconVar_{y,m}}{EconVar_{base\ yr,m}}\right) \times \left(\frac{Price_{y,m}}{Price_{base\ yr,m}}\right)^{-0.10} \qquad (6)$$

Where:

- *HDD* is the number of heating degree days in month (m) and year (y).
- *EconVar* is the weighted commercial economic variable that blends Output, Employment, and Population in month (m), and year (y).
- *Price* is the average real price of electricity in month (m) and year (y).

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to one in the base year. The first term, which involves heating degree days, serves to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will reflect changes in commercial output and prices, as transformed through the end-use elasticity parameters. For example, if the real price of electricity goes up 10% relative to the base year value, the price term will contribute a multiplier of about .98 (computed as 1.10 to the -0.18 power).

Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days,
- Cooling equipment saturation levels,
- Cooling equipment operating efficiencies,
- Commercial output, employment, population, and energy price.

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$XCool_{y,m} = CoolIndex_y \times CoolUse_{y,m} \qquad (7)$$

Where:

- $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m),
- $CoolIndex_y$ is an index of cooling equipment, and
- $CoolUse_{y,m}$ is the monthly usage multiplier.

As with heating, the cooling equipment index depends on equipment saturation levels (*CoolShare*) normalized by operating efficiency levels (*Eff*). Formally, the cooling equipment index is defined as:

$$CoolIndex_y = CoolSales_{base\ yr} \times \frac{\left({CoolShare_y}/{Eff_y} \right)}{\left({CoolShare_{base\ yr}}/{Eff_{base\ yr}} \right)} \tag{8}$$

Data values in 2004 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in the base year. In other years, it will be greater than one if equipment saturation levels are above their base year level. This will be counteracted by higher efficiency levels, which will drive the index downward. Estimates of base year cooling sales are defined as follows.

$$CoolSales_{base\ yr} = \left(\frac{kWh}{Sqft}\right)_{Cooling} \times \left(\frac{CommercialSales_{base\ yr}}{\sum_e {kWh}/{Sqft_e}} \right) \tag{9}$$

Here, base-year sales for space cooling is the product of the average space cooling intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space cooling sales value is defined on the *BaseYrInput* tab. The resulting *CoolIndex* value in the base year will be equal to the estimated annual cooling sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, economic activity levels and prices. Using the COMMEND default parameters, the estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{CDD_{base\ yr}}\right) \times \left(\frac{EconVar_{y,m}}{EconVar_{base\ yr,m}}\right) \times \left(\frac{Price_{y,m}}{Price_{base\ yr,m}}\right)^{-0.15} \tag{10}$$

Where:

- *HDD* is the number of heating degree days in month (m) and year (y).
- *EconVar* is the weighted commercial economic variable that blends Output, Employment, and Population in month (m), and year (y).
- *Price* is the average real price of electricity in month (m) and year (y).

By construction, the *CoolUse* variable has an annual sum that is close to one in the base year. The first term, which involves cooling degree days, serves to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will change to reflect changes in commercial output and prices.

Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Equipment saturation levels,
- Equipment efficiency levels,
- Average number of days in the billing cycle for each month, and
- Real commercial output and real prices.

The explanatory variable for other uses is defined as follows:

$$\mathrm{XOther}_{y,m} = \mathrm{OtherIndex}_{y,m} \times \mathrm{OtherUse}_{y,m} \tag{11}$$

The second term on the right-hand side of this expression embodies information about equipment saturation levels and efficiency levels. The equipment index for other uses is defined as follows:

$$OtherIndex_{y,m} = \sum_{Type} Weight_{base\ yr}^{Type} \times \left(\frac{Share_y^{Type} / Eff_y^{Type}}{Share_{base\ yr}^{Type} / Eff_{base\ yr}^{Type}} \right) \tag{12}$$

Where:

- *Weight* is the weight for each equipment type,
- *Share* represents the fraction of floor stock with an equipment type, and
- *Eff* is the average operating efficiency.

This index combines information about trends in saturation levels and efficiency levels for the main equipment categories. The weights are defined as follows.

$$Weight_{base\ yr}^{Type} = \left(\frac{kWh}{Sqft}\right)_{Type} \times \left(\frac{CommercialSales_{04}}{\sum_e kWh/Sqft_e} \right) \tag{13}$$

Further monthly variation is introduced by multiplying by usage factors that cut across all end-uses, constructed as follows:

$$OtherUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{EconVar_{y,m}}{EconVar_{base\ yr,m}}\right) \times \left(\frac{Price_{y,m}}{Price_{base\ yr,m}}\right)^{-0.15} \tag{14}$$

Burlington Electric Department

Economic Impact of McNeil Generating Station

A Report from:

Innovative Natural Resource Solutions, LLC

June 26, 2023

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Introduction

Burlington Electric Department's McNeil Station is a 50 MW wood-fired electricity generating facility[i] that operates in the ISO-New England region. This facility provides an important market for biomass chips, produced in the forests of Vermont and nearby New York, and provides electricity to consumers in the City of Burlington, Vermont, and surrounding communities, as well as the entire ISO-New England market and is currently the largest generator in Vermont in terms of energy production (following the retirement of Vermont Yankee).

Innovative Natural Resource Solutions LLC (INRS) was commissioned by Burlington Electric Department to analyze the economic impacts associated with operations of McNeil Station. This economic analysis is an update of a similar study performed in the spring of 2020. The analysis is for one year, and uses 2022 data whenever possible. There were a few occasions when 2022 data was not available; in those cases, the latest available data was utilized.

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Executive Summary

In 2022, the expenses to operate McNeil Station – inclusive of wood fuel, operations, maintenance, and other expenses (but excluding non-cash expenses such as depreciation, and cash expenses such as capital additions that do not appear in a financial statement of expenses) was $25,858,867. The facility generated an estimated $33,346,332 in revenue – from the sale of electricity, Renewable Energy Certificates (RECs), capacity and Volt Ampere Reactive (VAR) payments.

In addition to its recorded expenses, McNeil made purchases of capital assets not included in the above accounting treatment of "expenses" of $2,243,900.

McNeil Station provides significant economic benefit to Vermont and the surrounding region through the operations of the facility, purchase, and handling of wood fuel, and avoided societal cost of carbon emissions. Note the table below differs from a traditional income statement in that it includes dollars spent on wood purchases (not the amount of wood consumed and expensed), the expenditures on capital additions (which do not appear on an income statement), and a calculated value of CO2 savings (based on an assumption of carbon neutrality). The facility, Vermont's largest wood-using and largest energy producing facility, provides:

- $38.4 million in annual direct economic impact, 69 percent of which is in Vermont (see Table 1 below); and
- $87.2 million in annual direct, indirect, and induced economic impact, 66 percent of which is in Vermont (see Table 5 on page 14).

	Direct		
	Vermont Only	Total Impact	Jobs
Wood Fuel Purchases	$ 4,953,577	$ 12,142,622	48
* Swanton Yard Expense	$ 808,174	$ 808,174	2.5
* Railroad Expense	$ 1,800,000	$ 1,800,000	2
* Waste Wood Chipping Expense	$ 96,106	$ 96,106	
Fuel - Non-Wood Purchases	$ 7,793	$ 77,926	
Payroll Expense	$ 3,300,000	$ 3,300,000	34
Overhead Expense	$ 1,170,637	$ 1,170,637	
Property Tax Expense	$ 1,609,254	$ 1,609,254	
Other Operating Expenses	$ 941,028	$ 3,764,110	
Capital Purchases	$ 560,975	$ 2,243,900	
Carbon (avoided $)	$ 11,397,071	$ 11,397,071	
Total	***$ 26,644,614***	***$ 38,409,800***	***87***

Table 1. Direct Economic Impact, 2022

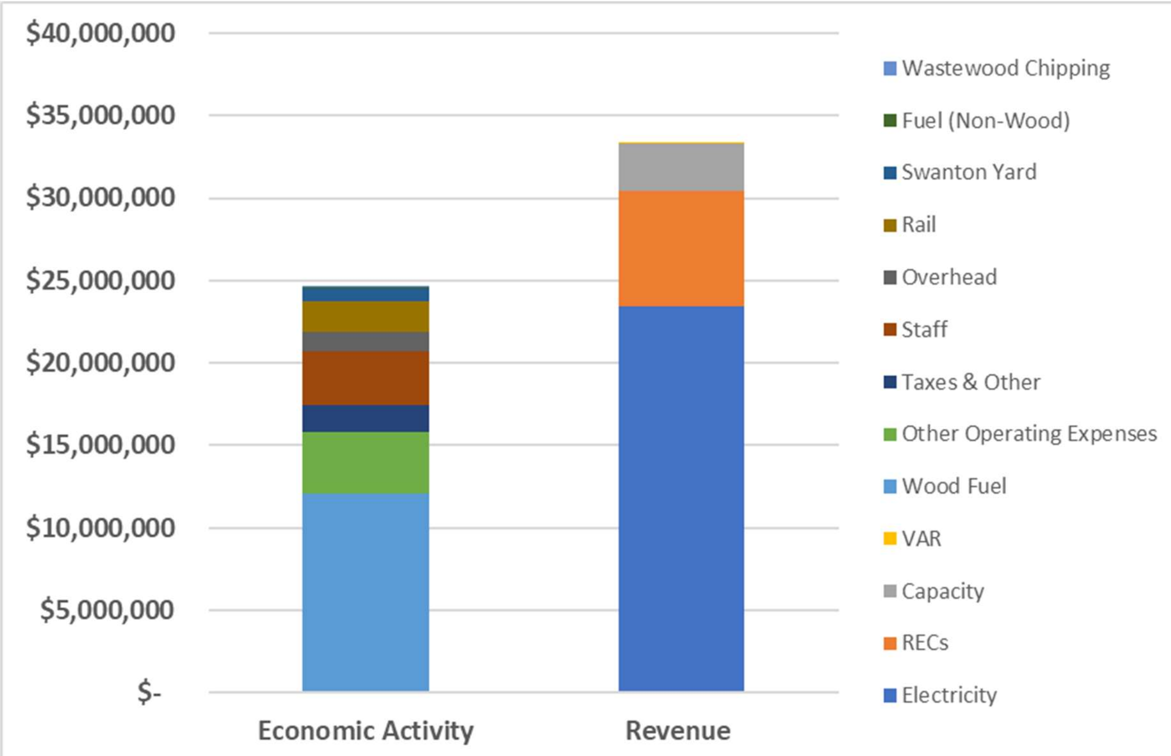

Figure 1. *Economic Activity and Revenue*

Wood Fuel

McNeil Station procures biomass fuel from loggers and others in the forest products industry. The vast majority of this fuel (88.4%) is procured as chips – generally obtained from harvesting projects that utilize in-woods chippers to produce fuel. In these harvesting operations the majority of the wood harvested is used for other purposes, such as sawlogs for lumber or pulpwood for papermaking, and the balance of the tree such as the tops and limbs are then chipped and used by McNeil as fuel, referred to as "in-woods chips." An additional 9.7% of fuel is mill residue (bark, mill chips, hog chips, and sawdust) from sawmills – the residuals generated when round logs are sawn into boards. McNeil Station does purchase some small volumes of roundwood (from lower value trees not appropriate for lumber or other higher value uses), which can be stored and used during time periods when loggers are unable to operate due to soft ground conditions – generally during the spring mud season. Fuel purchased as roundwood only made up 0.3% of McNeil's fuel supply in 2022. Lastly McNeil operates a waste wood yard for Vermonter's (including businesses) to dispose of clean untreated wood waste which is then chipped for fuel for McNeil (1.6%).

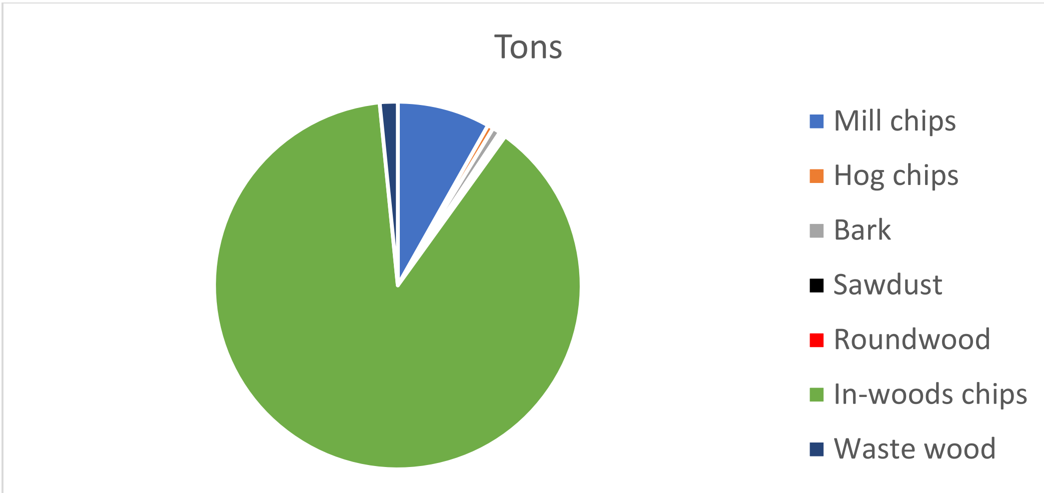

Figure 2. *Wood Fuel Type, by Volume*

The generation station purchased a total of 351,378 green tons of wood fuel in 2022[ii], making it the largest consumer of wood in Vermont, using wood equivalent to about 16 percent of Vermont's total timber harvest.[iii] McNeil Station purchases wood from nine Vermont counties, as well as from proximate counties in New York. Unlike fossil fuels that are imported from outside of the State and region, or other renewable generation sources that do not require ongoing fuel expenses (e.g., solar and wind), biomass electricity generation creates local economic benefits through ongoing wood fuel purchases. Assuming an average wood fuel price of $35 per green ton[iv], McNeil Station purchased $12.1 million in wood fuel in 2022. The figure below shows estimated wood fuel purchases in each Vermont county. In addition to what is shown below, the facility purchased $7.2 million in fuel from Clinton, Essex, Franklin, and Warren Counties in New York.

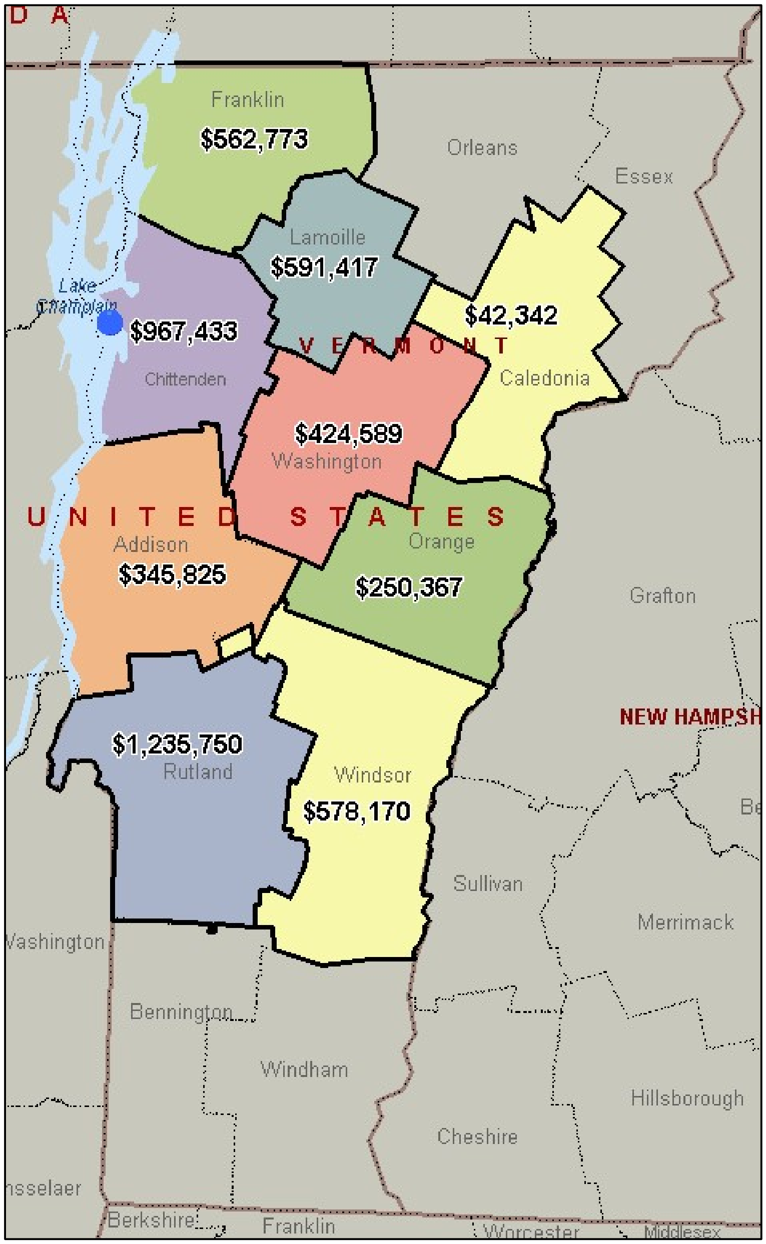

Figure 3. *Wood Fuel Purchases by Vermont County, 2022 (estimated)*[v]

In addition to dollars directly spent on wood fuel, the market for biomass fuel created by McNeil Station creates jobs. Logging crews produce biomass as part of a mix with other forest products, including sawlogs and pulpwood. The figure below shows how multiple products can be generated from a single tree or timber stand.

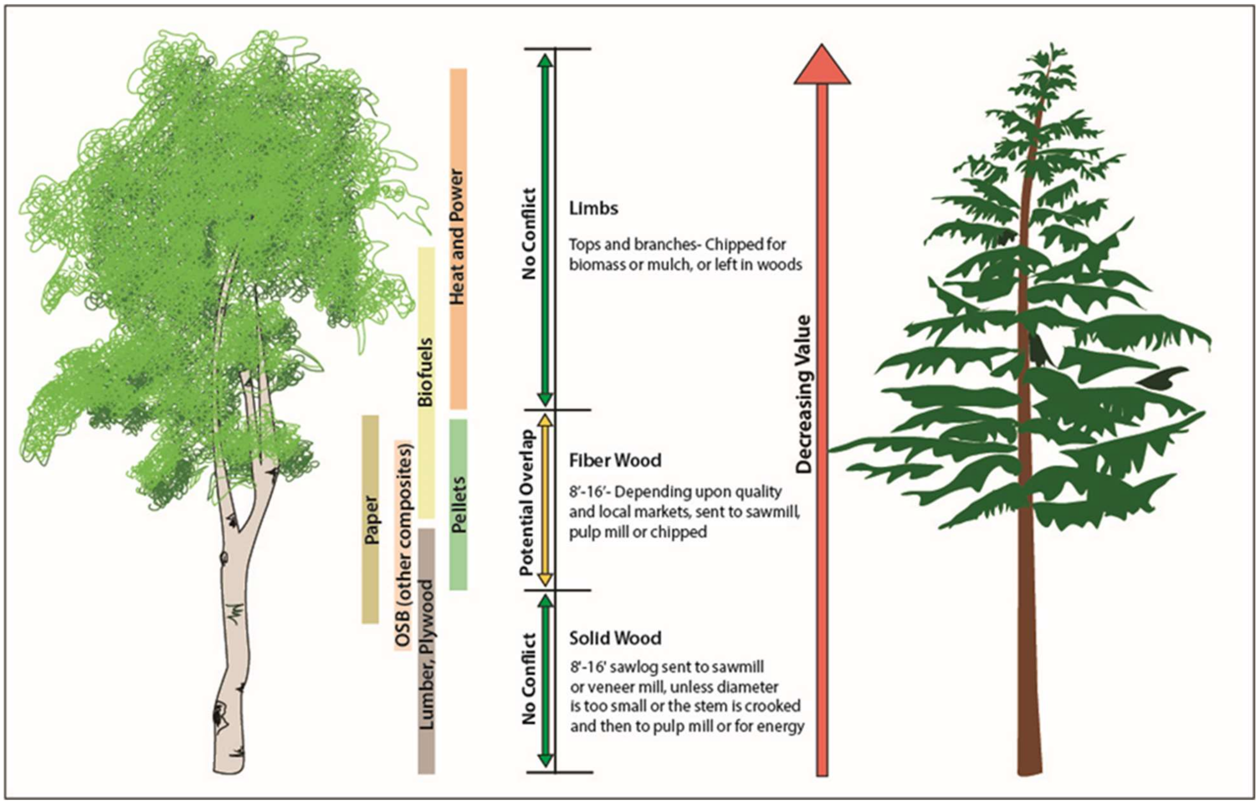

Figure 4. *Sawlogs, Pulpwood and Biomass Can All Be Generated from a Timber Harvest*

Assuming that a 4-person logging crew (exclusive of trucking) can produce 35 loads per week, at 30 tons per load, these 4 loggers would generate an estimated 1,050 tons of wood per week. Because loggers cannot work the entire year (often spring and fall mud season conditions keep loggers from operating for extended periods of time), we assume 45 weeks of operation per year. Given the above assumptions, McNeil Station's annual wood use directly supports the production of 30 full-time (FTE) logging jobs. According to data from the US Bureau of Labor Statistics[vi], the average wage for a logging equipment operator in Vermont is $40,017 per year. Using this wage, the market created by McNeil Station results in an estimated $1.2 million in logging wages annually.

In addition to logging jobs, providing wood fuel to the facility requires trucks, and thus generates trucking jobs. Again assuming 30 tons per load, McNeil Station's wood use requires 11,713 deliveries per year, or 45 deliveries per day (assumes 260 delivery days). Assuming that each truck can make 2.5 deliveries per day, this means that McNeil Station supports 18 trucks and FTE truckers. According to data from the US Bureau of Labor Statistics[vii], the average wage for trucker in Vermont $51,150 per year. Using this wage, the market created by McNeil Station results in $920,700 in trucking wages annually.

Wood Handling, Rail Transport, and Waste Wood Operations

In addition to the employment related to wood purchases described above, McNeil Station has a unique situation where most of the wood fuel used at the facility is required to be delivered to a remote yard in Swanton, Vermont and then sent to the facility via a short-line rail carrier. This arrangement, which adds to the delivered cost of wood fuel, was established to decrease truck traffic in the area around McNeil Station.

In 2022, the majority of wood fuel purchased by McNeil Generating Station was delivered to Swanton, unloaded, stored on site, and re-loaded into rail cars. Operations at this yard cost McNeil Station roughly $808,000 in 2022. The Swanton yard employs an estimated 2.5 people to conduct these activities.[viii] Assuming a wage similar to an agricultural equipment operator at $37,230[ix], the operation of the Swanton yard provides an estimated $93,075 in wages annually.

Moving this wood from Swanton to McNeil Station by rail in Burlington costs an additional $1.8 million per year. The vast majority of this is the charge for trains, but also includes switching fees, weather-related delays, and charges for snow trains. The short-line rail uses two individuals to operate each chip train. Assuming a wage of $64,150[x], these two rail jobs provide $128,300 in wages annually.

> *INRS notes that the yard and rail costs, spread over all wood fuel used (including any delivered directly to McNeil Station via truck) add $7.42 per ton to the average cost of fuel. Assuming 1.6 green tons of wood fuel are used to generate a megawatt hour of electricity[xi], this means an increased fuel cost of $11.88 per MWh associated with the permit requirement to deliver the majority of the wood to Swanton yard and then transport to McNeil via rail.*

In addition to wood procured via forestry operations and from mill residues, McNeil Station has an on-site wood waste yard where individuals can drop off pallets, untreated lumber, tree trimmings and other clean wood for use as a fuel. McNeil Station then pays a contractor to come in three times annually to grind the wood waste, allowing it to be sized for use as biomass fuel. This costs roughly $90,000 per year. In 2022 McNeil Station's waste wood program generated 5,573 tons of wood fuel for use at the facility[xii]. At an avoided cost of $50 per ton (avoided tipping fee)[xiii], the waste wood yard provided Vermont residents and businesses a value of $278,650 in 2022.

Plant Operations

Operating McNeil Station requires a professional staff to operate the facility. As an intermediate to baseload generator (depending on season), McNeil Station is staffed around the clock for the entire year and is always available for generation (with the exception of planned maintenance periods and unplanned outages). McNeil Station employs 34 full time staff, with an annual payroll of $3.3 million and overhead (benefits, employee costs, etc.) of nearly $1.2 million. Total staffing costs for McNeil Station are roughly $4.5 million annually.

McNeil Station makes an annual Payment in Lieu of Tax to the City of Burlington. In 2022 that PILT was $1.6 million.

There are a number of costs associated with plant operations that can be described as "Miscellaneous Operating Expenses." These include utilities, materials & supplies, dues, outside technical services, repairs and maintenance, professional training, phones, and publications. In 2022, these costs were roughly $3.8 million.

Thus, McNeil Station is responsible for the creation of a total of 87 jobs at the facility and in the wood fuel supply chain, with total wages for these positions estimated to be $5.6 million annually as discussed in more detail below.

Generation Revenue & Operating Expenses

McNeil Station generated 228,981 MWh of electricity for sale in 2022 and received payments for electricity and Renewable Energy Certificates (RECs) associated with this generation. Additionally, the facility received capacity payments from ISO-New England for being available to generate electricity when called upon, and Volt Ampere Reactive (VAR) payments for the value of generation near an electricity load center (the City of Burlington).

As shown in the table below, these generation-related revenues provided an estimated $33.3 million in revenue to McNeil Station in 2022.

	Electricity sales (MWh)		228,981
Electricity			
	Electricity revenue ($/MWh)	$	102.35
	Electricity Revenue	$	23,436,975
Renewable Energy Certificates			
	REC Revenue ($/MWh)	$	30.56
	REC Revenue	$	6,998,656
Capacity			
	Capacity ($/kw/kW month)	$	4.22
	Capacity ($ / MW month)	$	4,215
	MW per month		52
	Total Capacity Payment	$	2,886,229
VAR Payments			
	VAR Payments	$	24,472
Total			
	Total Generation Revenue	*$*	*33,346,332*

Table 2. *Generation-based Revenue, 2022*

This is revenue brought in through operations of the facility in the New England wholesale electric markets operated by ISO-NE. Importantly, the total revenue is not included in calculating the total economic impact of McNeil Station because in part these same funds that are used to purchase wood fuel, pay employees, and cover other expenses. To include the total revenue in the final calculation would be double counting. However, for the period examined, McNeil's revenues exceeded its expenses materially (see below in the Section on Direct Economic Impact).

Additionally, McNeil Station's operations support the electricity grid in Northwestern Vermont. According to information provided by the Vermont Electric Power Company (VELCO), if McNeil Station was not operating, that could create a "problem for the local area encompassing the City of Burlington, Essex and Winooski", and that "the 34.5 kV lines around McNeil could be overloaded during relatively heavy load days."[xiv]

While generating an estimated $33,346,332 in revenue, the facility incurred $25,858,867 in expenses[xv] – wood fuel, operations, maintenance, and taxes (PILT).

Summary – Direct Economic Impact

Based on the information above, in 2022 McNeil Station had a direct economic impact of $38.4 million, 69 percent of which is in Vermont (much of remainder is associated with wood fuel purchases from proximate New York)[xvi].

	Direct		
	Vermont Only	Total Impact	Jobs
Wood Fuel Purchases	$ 4,953,577	$ 12,142,622	48
* Swanton Yard Expense	$ 808,174	$ 808,174	2.5
* Railroad Expense	$ 1,800,000	$ 1,800,000	2
* Waste Wood Chipping Expense	$ 96,106	$ 96,106	
Fuel - Non-Wood Purchases	$ 7,793	$ 77,926	
Payroll Expense	$ 3,300,000	$ 3,300,000	34
Overhead Expense	$ 1,170,637	$ 1,170,637	
Property Tax Expense	$ 1,609,254	$ 1,609,254	
Other Operating Expenses	$ 941,028	$ 3,764,110	
Capital Purchases	$ 560,975	$ 2,243,900	
Carbon (avoided $)	$ 11,397,071	$ 11,397,071	
Total	***$ 26,644,614***	***$ 38,409,800***	***87***

Table 3*. Direct Economic Impact, 2022*

McNeil Station is responsible for the creation of 87 jobs at the facility and in the wood fuel supply chain, with total wages for these positions estimated to be $5.6 million annually.

Importantly, these jobs are maintained as long as McNeil Station is operating and using wood fuel. This is in contrast with some other forms of renewable electricity generation, where most jobs are associated with the development and construction of generation units, not their ongoing operations.

The revenue in excess of economic activity (purchases excluding capital and expenses) in 2022 was roughly $8.5 million, which provides a benefit to the owners of McNeil Generating Station[xvii], all of which are based in Vermont. This money circulates in the Vermont economy, and encourages continued operation of and investment in the facility. To be clear, McNeil Generating Station has not had revenues in excess of expenses every year of operation.

Multiplier Effect

INRS has reviewed relevant literature to estimate the multiplier effect for each relevant area of economic activity. The multiplier effect, used in economics to provide an understanding of the economic impact of activities, is defined as:

> *"Multiplier effect: means the cumulative economic activity arising from the fact that the biomass electric power generation industry's direct effect contribution spreads across the state's economy by creating and supporting jobs, incomes, and taxes. The biomass electric power generation industry supports its supply industries in the region by making purchases from them (indirect effect). These supply industries include commercial logging, marketing research, truck transportation, and maintenance and repair construction. In addition, workers in the biomass electric power generation industry and its supply industries spend their earnings in the region's services industries (induced effect), such as restaurants, medical services, grocery stores, real estate, and retail stores."*[xviii]

The table below shows the multipliers used for each economic activity, and the reference determined through a literature review.

	Multiplier	Reference
Wood Fuel Purchases	3.10	Plymouth State
* Swanton Yard Expense	3.10	Plymouth State
* Railroad Expense	1.71	ASLRRA
* Waste Wood Chipping Expense	2.10	Hardy, Stevenson & Assoc
Fuel - Non-Wood Purchases	1.00	xx
Payroll Expense	4.39	Plymouth State (calculated)
Overhead Expense	4.39	Plymouth State (calculated)
Property Tax Expense	1.78	Plymouth State (calculated)
Other Operating Expenses	1.60	Plymouth State (calculated)
Capital Purchases	1.69	Polecon Research (calculated)
Carbon (avoided $)	1.00	xx

Table 4. *Multipliers by Category*

Summary – Total Economic Impact

Using the information above, after adjusting for the multiplier effect, the total economic impact of McNeil Station is estimated at $87.2 million; 66 percent of this impact is in Vermont.

	Direct, Indirect & Induced	
	Vermont Only	Total Impact
Wood Fuel Purchases	$ 15,356,089	$ 37,642,128
* Swanton Yard Expense	$ 2,505,339	$ 2,505,339
* Railroad Expense	$ 3,078,000	$ 3,078,000
* Waste Wood Chipping Expense	$ 201,823	$ 201,823
Fuel - Non-Wood Purchases	$ 7,793	$ 77,926
Payroll Expense	$ 14,487,000	$ 14,487,000
Overhead Expense	$ 5,139,096	$ 5,139,096
Property Tax Expense	$ 2,864,472	$ 2,864,472
Other Operating Expenses	$ 1,505,644	$ 6,022,576
Capital Purchases	$ 948,048	$ 3,792,191
Carbon (avoided $)	$ 11,397,071	$ 11,397,071
Total	***$ 57,490,375***	***$ 87,207,623***

Table 5. *Total Economic Impact*

As in the direct evaluation above the revenue in excess of economic activity (purchases excluding capital purchases and expenses) in 2022 was roughly $8.5 million, which provides a benefit to the owners of McNeil Generating Station[xix], all of which are based in Vermont. This money circulates in the Vermont economy, and encourages continued operation of and investment in the facility. Importantly, McNeil Generating Station has not had revenues in excess of expenses every year of operation.

Endnotes

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[i] https://www.burlingtonelectric.com/mcneil/
[ii] Personal communication, Burlington Electric Department staff, Material Report 2022
[iii] Calculated from Vermont Forest Resource Harvest Summary - 2021. https://fpr.vermont.gov/sites/fpr/files/doc_library/2021%20Harvest%20Report.pdf. Assumes 1 cord is equivalent to 2.5 green tons.
[iv] Personal communication, Burlington Electric Department staff
[v] Estimates based on an average price of $39.80 per green ton.
[vi] May 2021 State Occupational Employment and Wage Estimates – Vermont. https://www.bls.gov/oes/current/oes_vt.htm#45-0000
[vii] May 2021 State Occupational Employment and Wage Estimates – Vermont. https://www.bls.gov/oes/current/oes_vt.htm#45-0000
[viii] Personal communication, Burlington Electric Department staff
[ix] May 2018 State Occupational Employment and Wage Estimates – Vermont. https://www.bls.gov/oes/current/oes_VT.htm#45-0000
[x] U.S. Bureau of Labor Statistics, Occupational Outlook Handbook, Transportation and Material Moving, Railroad Workers. https://www.bls.gov/ooh/transportation-and-material-moving/railroad-occupations.htm
[xi] "Amended and Restated Power Purchase Agreement, Public Service of New Hampshire and Berlin Station," Approved in Docket DE-10-195 of the New Hampshire Public Utilities Commission. Section 6.1.2(a)(2) implies that facility, a 70 MW biomass unit, would burn 1.6 tons of fuel per MWh.
[xii] Personal communication, Burlington Electric Department staff
[xiii] https://cswd.net/a-to-z/wood/
[xiv] Email from VELCO (Hantz Presume) to Burlington Electric Department (Casey Lamont), July 15, 2019
[xv] Personal communication, Burlington Electric Department staff
[xvi] For the categories "Other Operating Expenses" and "Capital Expenditures," it was assumed that 25% of the activity is in Vermont. For "Fuel: Non-Wood," it was assumed 10% of the economic activity was in Vermont.
[xvii] The joint owners of McNeil Generating Station are Burlington Electric Department, Green Mountain Power, and the Vermont Public Power Supply Authority.
[xviii] Daniel S. Lee, College of Business Administration, Plymouth State University (New Hampshire). *Economic Contribution of the Biomass Electric Power Generation Industry in New Hampshire: Calendar Year 2016.* March 1, 2017
[xix] The joint owners of McNeil Generating Station are Burlington Electric Department, Green Mountain Power, and the Vermont Public Power Supply Authority.