2023 Annual Energy Report

A summary of progress made toward the goals of Vermont's Comprehensive Energy Plan

Prepared by the Vermont Department of Public Service

January 15, 2023

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Revision History

1. January 15, 2023: Initial publication
2. January 17, 2023: Corrected two typographical errors and clarified the Agency of Natural Resource's guidance on biomass emissions factors (page 11)

Introduction and Overview

Vermont's energy policy, as articulated in statute, is:

> To assure, to the greatest extent practicable, that Vermont can meet its energy service needs in a manner that is adequate, reliable, secure, and sustainable; that assures affordability and encourages the State's economic vitality, the efficient use of energy resources, and cost-effective demand-side management; and that is environmentally sound.[1]

Vermont's Comprehensive Energy Plan[2], released in January 2022, recognizes that these goals are sometimes in competition. The plan balances the principles of Vermont energy policy of energy adequacy, reliability, security, and affordability, which are all essential for a vibrant, resilient, and robust economy, and for the health and well-being of all Vermonters. In doing so, the Comprehensive Energy Plan (CEP) builds upon and re-established long-standing high-level goals: **To meet 25% of Vermont's energy needs from renewable sources by 2025, 45% by 2035, and 90% by 2050**. In addition, the CEP sets sector specific targets:

- In the transportation sector, meet 10% of energy needs from renewable energy by 2025, and 45% by 2040;
- In the thermal sector, meet 30% of energy needs from renewable energy by 2025, and 70% by 2042; and
- In the electric sector, meet 100% of energy needs from carbon-free resources by 2032, with at least 75% from renewable energy.

These targets, and the pathways, strategies, and recommendations outlined in the CEP, are designed to be consistent with the greenhouse gas requirements of the Global Warming Solutions Act (GWSA),[3] and to be consistent with the Climate Action Plan prepared by the Vermont Climate Council. The CEP recognizes that the current energy system is marked by systemic inequities that have a disproportionate impact on many of Vermont's communities, and that the transition required to meet our targets presents us with opportunities to root out and redress those existing inequalities.

This Annual Energy Report is designed to provide objective data as well as transparency regarding the policies pursued by the Department of Public Service (PSD). With the recent release of the Comprehensive Energy Plan, the Annual Energy Report is organized differently than in years past. It begins by providing an overview of the major themes of 2022 Comprehensive Energy Plan, including equity and grid evolution. It discusses coordination with the Climate Council and greenhouse gas emission reduction reporting, and highlights the significant opportunity afforded to Vermont's energy future by generational federal funding. Each sector will then be examined based on major trends or initiatives, before providing

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[1] 30 V.S.A. § 202a

[2] The Comprehensive Energy Plan can be found on the Department's website.

[3] 10 V.S.A. § 592

objective data in simple exhibits. Emphasis has been placed on limiting text that is otherwise replicated in the CEP or elsewhere. Importantly, Appendix A distills every recommendation in the Comprehensive Energy Plan and assesses progress on those recommendations.

1.1 2022 Comprehensive Energy Plan Theme: Equity

Chapter 3 of the 2022 Comprehensive Energy Plan set forth foundational considerations of how to achieve state energy goals in a just and equitable manner. It did so by discussing definitions and dimensions of energy equity and outlining principles and priorities for future action, drawing on guidance established by the Vermont Climate Council's Just Transitions subcommittee. The chapter put forward a series of recommendations for how to advance equity as the state works to achieve its renewable energy and climate objectives. After the 2022 CEP was published, Act 154 of 2022 was signed into law, establishing an environmental justice policy for Vermont which aligns with many of the concepts discussed in the 2022 CEP.[4] New obligations were placed on many of Vermont's state agencies, including the Department of Public Service, to help ensure equitable distribution of environmental benefits and burdens and meaningful participation in decision-making on issues related to energy, climate change, and the environment. These include:

- Conducting a three-year historical review of investments leading to environmental benefits, where those investments occurred, and who benefited from them at the municipal and census block group level;
- Having a goal of directing investments proportionately to environmental justice focus populations;
- Reporting annually on investments leading to environmental benefits and where those investments occur at the municipal and census block group level;
- Developing a community engagement plan to describe how the Department will engage with environmental justice focus populations as it evaluates new and existing activities and programs;
- Participating in the Interagency Environmental Justice Committee to support State agency implementation of the Environmental Justice State Policy; and
- Adopting or amending policies and procedures, plans, guidance, and rules, where applicable, to implement the state policy.

Although these requirements will phase in over the next three years, state agencies are already making preparations to meet these obligations.[5]

In addition to new forthcoming obligations under Act 154, the Department has also been closely monitoring the Justice40 initiative established by President Biden's Executive Order 14008,[6]

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[4] Act 154 of 2022

[5] For example, in 2022 the Department of Public Service developed a new role within the planning division, Data & Equity Policy Manager, to bring dedicated resources and capacity to advance this work.

[6] https://www.whitehouse.gov/briefing-room/presidential-actions/2021/01/27/executive-order-on-tackling-the-climate-crisis-at-home-and-abroad/

which establishes a goal that 40 percent of the overall benefits of certain federal investments (including those related to clean energy, energy efficiency, and workforce development) will be directed towards disadvantaged communities.[7] In July 2022, the U.S. Department of Energy (DOE) announced that 144 of their programs, including the State Energy Program and all those programs established by the bipartisan infrastructure law (Infrastructure Investment and Jobs Act, or IIJA) and Inflation Reduction Act (IRA), would be covered under the Justice40 initiative. In addition, the DOE outlined eight policy priorities it seeks to advance under the Justice40 initiative:[8]

- Decrease energy burden
- Decrease environmental exposure and burdens
- Increase clean energy jobs, job pipeline, and job training for individuals
- Increase clean energy enterprise creation and contracting
- Increase energy democracy
- Increase access to low-cost capital
- Increase parity in clean energy technology access and adoption, and
- Increase energy resiliency

Over the next year, the Department of Public Service will be working to integrate these priorities and requirements from both the federal and state levels into its work as it engages with the Interagency Environmental Justice Committee and develop programs with new federal funding (discussed in Section 1.4 below).

The 2022 CEP outlines seven recommended actions for the Department and other agencies to take to advance equity and justice while striving to meet state energy goals. These recommendations and the progress towards meeting them made over the last year are outlined in Appendix A.

1.2 2022 Comprehensive Energy Plan Theme: Grid Evolution

Chapter 4 of the 2022 Comprehensive Energy Plan is dedicated to the manner in which the electric grid is evolving to accommodate transformational changes to the way electricity is generated, delivered, and used, which must take place to enable energy-sector decarbonization through efficient and strategic use of distributed energy resources (DER). Other terms used for the concepts embodied in grid evolution are "grid optimization," "grid modernization," and "distribution system planning." The CEP examines grid optimization concepts, consequences, tradeoffs, and action steps in great detail and proposes Vermont adopt the following goal for so-called grid of the future:

[7] The DOE has developed a screening tool informed by cumulative burdens that identifies disadvantaged communities (DACs) based on indicators related to fossil dependence, energy burden, environmental and climate hazards, and socio-economic variables. That tool can be viewed at https://energyjustice.egs.anl.gov.

[8] Department of Energy, General Guidance for Justice40 Implementation (July 2022). https://www.energy.gov/sites/default/files/2022-07/Final%20DOE%20Justice40%20General%20Guidance%20072522.pdf

> A secure and affordable grid that can efficiently integrate, use, and optimize high penetrations of distributed energy resources to enhance resilience and reduce greenhouse gas emissions.

Several grid evolution initiatives underway at the time the CEP was published have advanced in the past year. Utilities and partners have expanded their flexible load programs, including the implementation of rates and other incentives to encourage electric vehicle charging outside of peak demand hours and the direct control of charging equipment, interconnected distributed battery storage, and other DERs. This provides greater opportunity for utilities to smooth demand and align it with times when supply is lower cost and less polluting. More utilities now have hosting capacity or generation constraint maps available to guide renewable development to areas of the grid with headroom to accommodate them, usually at lower cost to the developer. In addition, the Department initiated development of a tool to help Regional Planning Commissions understand grid constraints as they develop siting maps and supporting policies.

Appendix A provides additional detail on progress toward the recommended actions to pursue to further grid evolution from the 2022 CEP.

1.3 Climate Action Office

In 2022, the Agency of Natural Resources created the Vermont Climate Action Office (CAO), recognizing that the policies, programs, and tools needed to implement climate mitigation, adaptation, and resilience strategies put forward in the Comprehensive Energy and Climate Action Plans will require a long-term intergovernmental structure to coordinate and manage. The CAO will coordinate and lead in the implementation of state-led climate initiatives, as well as the monitoring, assessment and tracking of climate adaptation, mitigation, and resilience activities necessary to evaluate progress over time in meeting the State's greenhouse gas requirements. To carry out this work, the Office will work closely with other state Agencies, the state climatologist, and the Vermont Climate Council.

The CAO will have an Interagency Advisory Board that will meet regularly, comprised of representatives of the Department of Public Service, Agency of Transportation, Vermont Emergency Management, Agency of Agriculture, Food and Markets, Buildings and General Services, Agency of Human Services (including the Department of Children and Families and Department of Health), Agency of Commerce and Community Development, and the State Climatologist.

1.3.1 Greenhouse Gas Emissions Reporting

The Comprehensive Energy Plan was developed to be consistent with the Climate Action Plan and to set out pathways and strategies to meet Vermont's greenhouse gas emissions requirements "from within the geographical boundaries of the State and those emissions outside the boundaries of the State that are caused by the use of energy in Vermont" by:

- not less than 26% from 2005 GHG emissions by January 1, 2025;
- not less than 40% from 1990 GHG emissions by January 1, 2030; and
- not less than 80% from 1990 GHG emission by January 1, 2050.

Vermont's Agency of Natural Resources, historically through its Air Quality and Climate Division and now through the CAO, provides annual estimates on the amount of greenhouse gas emissions (GHG) by sector. The Vermont Greenhouse Gas Emissions Inventory and Forecast (GHG Inventory), competed pursuant to 10 V.S.A. § 582, establish historic baseline greenhouse gas levels and track changes in emissions through time to determine progress toward Vermont's GHG requirements. The most recent report published officially tracked emissions through 2017. The CAO is finalizing an update to the GHG Inventory that includes official estimates for three years (2018, 2019, and 2020) to provide as up-to-date data as possible. As shown below, a draft of the updated GHG Inventory shows overall emissions declined from 2017 through 2020, with variability within each sector. Estimates from 2020 may be an outlier due to the impacts of the COVID-19 pandemic, which had a significant impact on the transportation/mobile sources sector, reducing emissions by approximately 15% from 2019 to 2020. Electricity sector emissions from the previous report have been adjusted upward for the years 2016 through 2019 due to a calculation error in the previous report (explained further in the methodology section of the GHG Inventory and in Section 2.3.1 of this Annual Energy Report). Total emissions in 2020 were 7.99 million metric tons of CO_2-equivalent ($MMTCO_2e$).

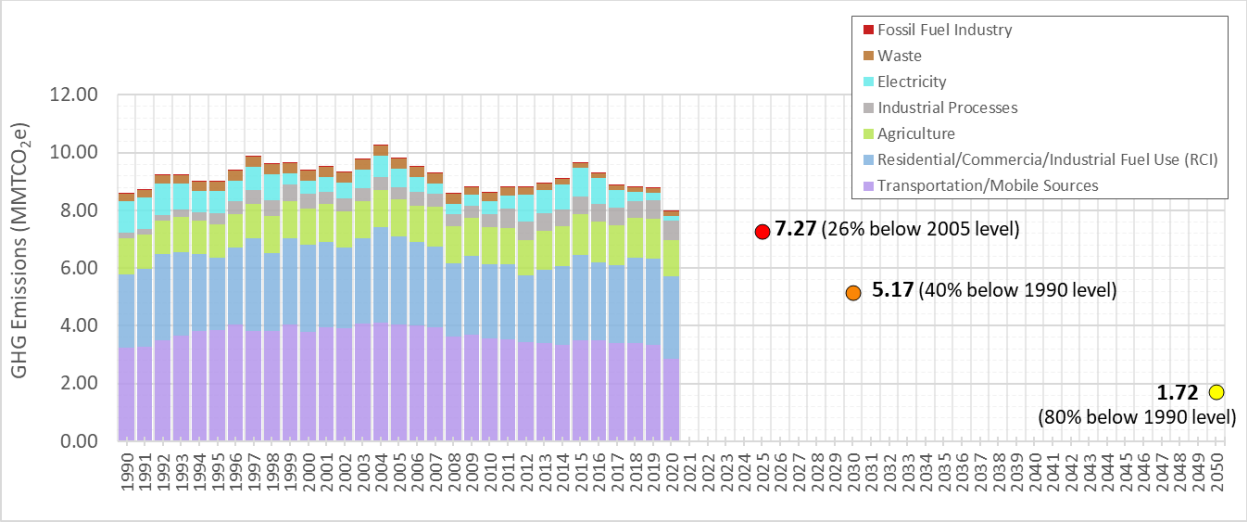


Figure 1: Past GHG Emissions and Future Targets

Once finalized, the full report will be available on the CAO website at https://climatechange.vermont.gov.

1.3.2 Relative Cost of Carbon Mitigation

There are many state programs that support Vermont's efforts to reduce GHG emissions, including renewable power supply requirements, energy efficiency, weatherization, advanced wood heating, and incentives for electric vehicles and cold climate heat pumps. These programs use a mix of public and private investment to lower emissions and incur both public and private costs and savings.

In past Annual Energy Reports, the Department of Public service created and reported on a tool to better understand how particular "measures" reduce carbon emissions relative to the costs and benefits of each action. In 2022, the Department and the CAO, as part of work associated with the Vermont Climate Council, engaged with consultants Cadmus, Energy Futures Group, and Stockholm Environment Institute to create a "Mitigation Abatement Curve" to examine both the potential for and the cost per metric tonne of emission-reduction measures in the CEP and the Climate Action Plan.[9] While there is not a single way to conduct such an analysis, it is nonetheless informative to understand relative impact of measures. The figure below shows is the Marginal Abatement Cost Curve (MACC) of measures implemented through 2030. The horizontal axis (and the width of each column) is cumulative emissions reduction potential over time. The vertical axis represents the net cost or benefit (if negative) of the measure.

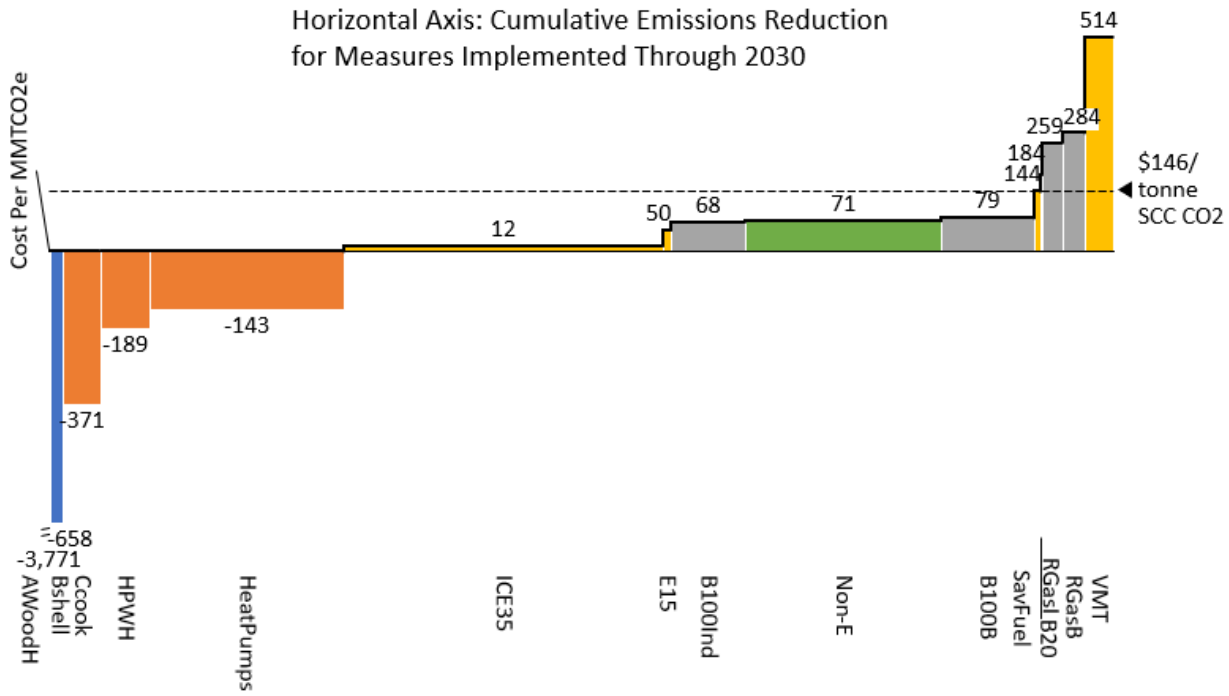


Figure 2: Marginal Abatement Cost Curve for Various Measures through 2030[10]

Measures vary in cost and potential quantity. For example, advanced wood heat is identified as being the most cost-effective measure through 2030, with reductions in vehicle miles traveled (VMT) being the most expensive. It must be noted that, like any modeling, the analysis here is directly related to the inputs. For example, emissions from biomass were, consistent with Agency of Natural Resources guidance,[11] assumed to be zero, while assumptions of the cost to achieve

[9] Energy Futures Group, Marginal Abatement Cost Curves Examining the Mitigation Potential and Cost per Tonne of Emissions Reductions of Measures in the Vermont Pathways Analysis (September 2022). https://outside.vermont.gov/agency/anr/climatecouncil/Shared%20Documents/MAC%20Curve%20Deliverable%20Memo%20Clean%20Version.pdf

[10] See Energy Futures Group report cited above, pages 13-15, for mitigation measure descriptions.

[11] The Vermont Climate Council has not determined a value for biomass-related emissions. The Council seeks to conduct a life-cycle assessment to identify appropriate emissions factors for various fuels.

VMT reductions were very high-level estimates. Therefore, the analysis indicates that there are mitigation measures that will never overcome their upfront costs, while others will result in net savings. This will reduce the overall cost of reducing emissions to the required levels.

All the measures analyzed need to be implemented to meet the 2030 and 2050 targets in the Climate Action Plan's central mitigation scenario. So, while ideally the GWSA targets could be achieved by implementing only measures with negative or low marginal abatement costs, those measures cannot be scaled to meet the targets. That said, it is useful to have a sense of the magnitude of initial potential and costs of certain measures. (Note, electric sector measures are not shown in the chart above.)

1.4 Federal Funding

Vermont, like other states, has received, will receive, and has the potential to access unprecedented amounts of federal funding through the American Rescue Plan Act (ARPA), the Infrastructure Investment and Jobs Act (IIJA, also called Bipartisan Infrastructure Law or BIL), and the Inflation Reduction Act (IRA).

Energy-related ARPA allocations, which have already begun or will begin in 2023, include:

- $80 million for weatherization programs, including $45 million to the Office of Economic Opportunity for low-income weatherization programs and installation of heat pumps and other devices, and $35 million to grant to Efficiency Vermont for weatherization incentives to Vermonters with moderate incomes. This funding, proposed by the Governor and passed by the Legislature in 2022, follows $7 million in ARPA funding allocated the year prior to Efficiency Vermont for moderate income weatherization and workforce development initiatives.
- $15 million to the Department of Public Service, $10 million of which was intended for "the Affordable Community-Scale Renewable Energy (ACRE) Program…to support the creation of renewable energy projects for Vermonters with low-income," and $5 million to be "allocated by the Clean Energy Development Board:"
    - The ACRE Program will deliver on-bill credits to eligible customers coming from the generation of renewable energy. Credits will come via participating distribution utilities, each offering a unique program with a range of credits of $12-45 for 5-10 years. These programs will serve as pilots, offering insight into different models of what an "Affordable Community-Scale Renewable Energy Program" can be, perhaps leading to a statewide program in the future and/or an alternative to net-metering.
    - The Clean Energy Development Fund developed several programs to allocate $5 million:
        - The School Heating Assistance with Renewables and Efficiency Program (SHARE) offers support to schools in need of financial assistance for heating repair, improvement, and upgrade projects. SHARE was initially funded with $2.5 million of the CEDF Board's $5 million allocation. An additional $1.25 million was transferred to the program following the

discontinuance of the Whole-Home Clean Energy Assistance Program and the Interest Rate Buydown Program. There has been significant interest in this program with funding requests for eligible projects totaling more than $11 million.

  - The Hospitality HVAC Assistance Program offers assistance to hospitality, tourism and travel services businesses that were negatively affected by the pandemic. The program is funded with $250,000, offering grants of $10,000-25,000 for HVAC repair, improvement and upgrade projects that were delayed due to the pandemic.
  - Several other programs were developed but ultimately not moved forward: The Whole-Home Clean Energy Assistance Program was designed to deliver $1 million of ARPA funding to households with low-income for efficiency measures and heating system improvements, but was duplicative of other state programs. An interest rate buydown was not allowed under the ARPA rules.

- $20 million to provide financial and technical assistance for low- and moderate-income Vermonters to upgrade home electrical systems, enabling installation of energy saving technologies.
- $5 million for a "Switch and Save" program to provide financial and technical assistance for Vermonters with low and moderate income to install, at low- or no-cost, heat pump water heaters, with a focus on replacing water heaters near the end of their useful life.
- $7 million for load management and storage efforts to assist Vermonters with low- and moderate-income customers to purchase electric equipment for heating, cooling, and vehicle charging. In addition, investments will be made in load control and management platforms to enable smaller municipal and cooperative utilities to capture and share benefits of load management and funding for municipal back-up electricity storage installations.
- $45 million for the Municipal Energy Resiliency Grant program to extend services and support to under resourced municipalities across Vermont. The funding provides $5 million in investment grade building assessments, $1 million for the creation of four limited-service staff positions, $2.4 million for Regional Planning Commissions (RPCs) support or program operations, and $36.6 million in project funds capped at $500,000 per municipality. Further funds are assigned via IIJA funds (see below) to establish a revolving loan fund for use by municipalities beyond the scope of ARPA monies.

Through the IIJA, the Department of Public Service will receive direct funding via four programs: State Energy Program (SEP), Energy Efficiency and Conservation Block Grant Program (EECBG), Energy Efficiency Revolving Loan Fund Capitalization Grant Program (EERLF), and Grid Resilience State Formula Grant Program. Two of the programs funding (EECBG and EERLF) were appropriated to the Department of Buildings and General Services through Act 172 of 2022. The U.S. Department of Energy has started to release solicitations for some of this funding.

The Department of Public Service anticipates receiving the following amounts for the programs:

- $3 million through an SEP formula grant to support electric transmission and distribution planning as well as planning activities and programs that save energy and help reduce carbon emissions in all sectors of the economy. The Department of Public Service has submitted its proposal for spending of these funds to the U.S. Department of Energy.
- $1,630,895 through the Energy Efficiency and Conservation Block Grant Program to reduce energy use, reduce fossil fuel emissions, and improve energy efficiency (appropriated to BGS in Act 172 of 2022).
- $775,660 through the Energy Efficiency Revolving Loan Fund Capitalization Grant Program to establish a revolving loan fund under which the State shall provide loans and grants for energy efficiency audits, upgrades, and retrofits to increase energy efficiency and improve the comfort of buildings (appropriated to BGS in Act 172 of 2022).
- $3.5 million (annually for five years) via the Grid Resilience State Formula Grant Program. The Department of Public Service will be applying for these funds in early 2023, with the goal of reducing the number and duration of electric utility outages, with funding expected to be distributed to distribution utilities.

Through the IRA passed in August 2022, the Department will receive direct funding via two programs: Home Energy Performance-Based Whole House Rebates (HOMES) and High-Efficiency Electric Home Rebate Program. The Department anticipates receiving approximately $29 million for each of the programs; however, the Department has not yet received any instructions or timeline estimates for when the IRA funds might be deployed.

Finally, both the IIJA and the IRA have significant funding to be allocated via competitive solicitations (some are competitive between States only, others competitive between all public and private entities). The Department of Public Service expects to review and strategically participate in solicitations.

1.5 Vermont's Clean Energy Economy

Vermont continues to lead the nation in the number of clean energy jobs per capita. Each year, the Department's Clean Energy Development Fund issues the Vermont Clean Energy Industry Report, drawing on data collected by the U.S. Department of Energy and its well-established methodology to characterize employment trends. The 2022 report shows that Vermont's clean energy economy gained 500 jobs in 2021 after shedding 1,400 jobs in 2020 during the COVID-19 pandemic. While the state's clean energy economy has begun recovering from 2020's unprecedented job losses, clean energy employment remained about 1,000 jobs below pre-pandemic levels at the end of 2021. Renewable energy and energy efficiency shed the most jobs between 2019 and 2020 but experienced only modest employment gains between 2020 and 2021. Clean transportation saw the largest increase in employment, growing by almost 20 percent and reaching an all-time high.

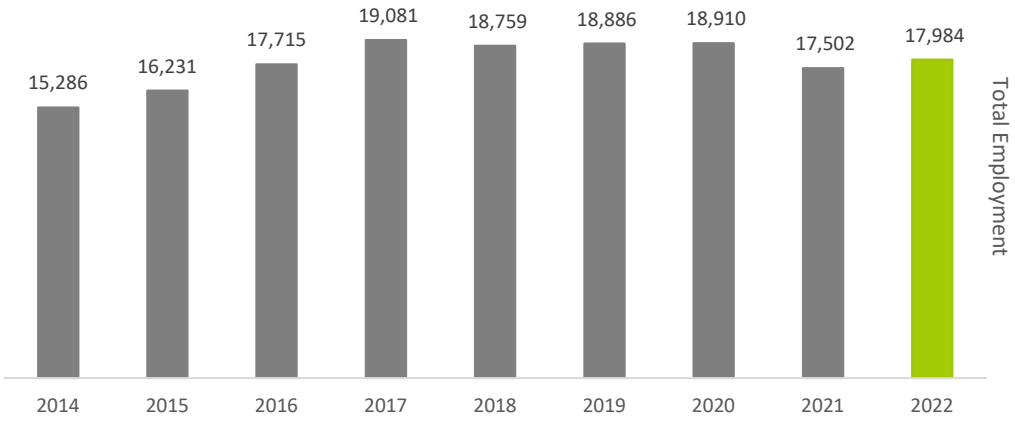


Figure 3: Total Annual Vermont Clean Energy Employment[12]

Clean energy workers are spending more of their time on clean energy activities. Within both the renewable energy an energy efficiency workforce, workers are more likely than ever to be spending at least 50% of their time on clean energy projects.

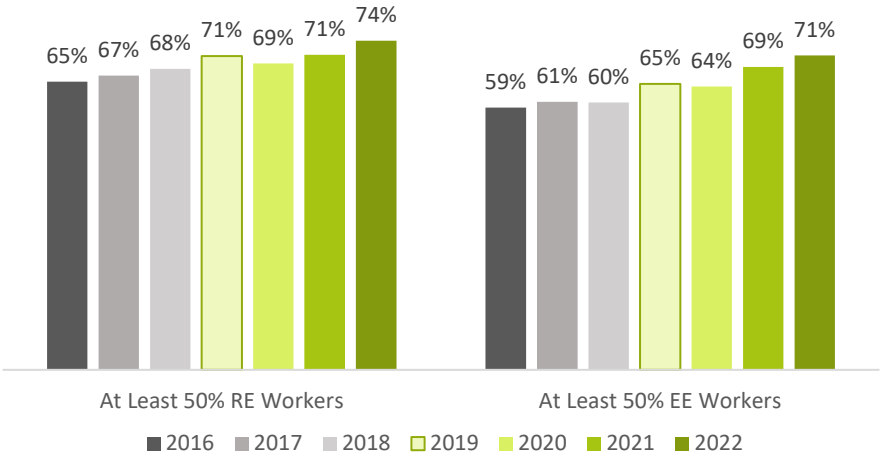


Figure 4: Percent of Renewable Energy and Energy Efficiency Workers that Spend at Least 50% of Their Time on Clean Energy Activities

Vermont's expanding clean energy industry is a key component to meeting the energy and greenhouse gas reduction requirements while building a vibrant local economy. As the sector expands, the clean energy industry can help make Vermont more affordable, provide economic opportunities around the state, and protect the state's most vulnerable people.

[12] Reports are available online at https://publicservice.vermont.gov/about-us/plans-and-reports/cedf-reports/vermont-clean-energy-industry-reports.

For more details on the clean energy industry and an exploration regarding the state's emerging battery storage sector, see the 2022 Vermont Clean Energy Industry Report on the PSD's Clean Energy Development Fund website.

1.6 Structure of the Annual Energy Report

This Annual Energy Report continues to describe major trends and initiatives in each sector. It then provides figures detailing latest information on energy supply and demand in each sector.

Appendix A provides a progress update toward each recommendation of the Comprehensive Energy Plan.

Appendix B is the Renewable Energy Report required by 30 V.S.A. § 8005(b).

Appendix C contains the Net Metering Report provided to the Public Utility Commission pursuant to 30 V.S.A. § 8010.

Appendix D contains a brief report on the Vermont Small Hydropower Assistance Program.

Electricity

Section 2 of this Annual Energy Report covers the Electricity sector. Appendix B and C discuss in detail renewable energy and net metering programs and policies, respectively. Section 2.1 Highlights major trends and initiatives in the electric sector; sections 2.2 to 2.4 provide information on supply, demand, and prices for electricity, respectively.

2.1 Major Trends and Initiatives

2.1.1 Renewable & Clean Energy Policy Review

To meet State renewable energy goals and greenhouse gas reduction requirements, the 2022 Comprehensive Energy Plan recommended (p. 270) that the State should:

> "Consider adjustments to the Renewable Energy Standard and complementary renewable energy programs comprehensively, through a transparent and open process…. The considerations should include:
>
> - Consideration of a low-carbon or carbon-free standard, in addition to a 100% renewable energy standard;
> - Consideration of a cohesive set of programs to support the standard."

This recommendation is consistent with recommendations included in the 2021 Climate Action Plan.

To begin implementing this recommendation to review Vermont's Renewable Energy Standard and related programs in a transparent process, on July 5, 2022, the Department issued a Request for Input (RFI). This RFI aimed to collect feedback from the public on three core issues related to the review:

- How should the process to review these programs and policies occur? In particular, what timeline should be considered, who should be at the table to shape policies and programs, and how should the Department engage with these stakeholders?
- What criteria should the Department use to make decisions and how should those criteria be prioritized?
- What key issues should be considered?

The Department received responses to this RFI from over 100 individuals and organizations via email, webform, and webinar. The Department issued a summary of the feedback received, particularly focused on the process questions in mid-October. At a high level, the Department's key takeaways from the RFI were that:

- The weight of the responses supported a longer timeline (for example, 12-18 months) to review renewable programs and policies to allow for a more inclusive and robust process.

    - Taking such an approach could offer more time to bring a broader array of stakeholders to the table and allow for educational and capacity building engagement early in the process to establish common knowledge about core issues under review.
    - Utilizing variety of public engagement methods could help understand stakeholder needs and ideas about policy and program changes, including polling or surveys, interactive workshops and stakeholder forums, attendance at community events, and public comment forums, among others.
  - Responses to the RFI highlighted the complexity of the topic under consideration and the ways considerations extend beyond the types of resources that produce electricity.
    - Holistically and comprehensively addressing the issues highlighted will take time, a shared understanding of terms, and careful scoping of what can be accomplished within this process and what issues may be addressed in complementary processes, programs, and policies.

Informed by responses to the RFI and available resources, on December 1, 2022 the Department released its proposed public engagement plan, which outlines a vision of how the process to review renewable electricity programs and policies could unfold over the next year. The plan outlines three core phases of the public engagement process, which would be complemented by technical analyses:

- **Phase 1 – Awareness and Education** (November 2022 – March 2023), will focus on broad outreach, especially to frontline & impacted communities, to raise awareness of this effort and create educational opportunities to build capacity to engage in future conversations. This will include educational webinars and other outreach with identified partners.
- **Phase 2 – Policy and Program Review** (April – August 2023), will focus on reviewing existing programs and policies and developing recommendations for changes through continued stakeholder engagement and supporting technical analyses. Public engagement opportunities are expected to include venues like interactive workshops and surveys or polling.
- **Phase 3 – Recommendations and Reporting** (September – December 2023), will focus on finalizing and drafting recommendations and producing summary reports on the process taken to arrive at those recommendations. Drafts of the documents would be reviewed and revised through public comment periods. The reports are expected to be finalized in advance of the 2024 Legislative Session.

By design, the proposed plan leaves room for flexibility as new ideas about or needs for public engagement emerge throughout the process acknowledging not all communities were reached by or responded to the initial RFI. In undertaking this process, the Department aims to produce the following outcomes in advance of the 2024 legislative session:

- A comprehensive suite of recommendations related to how Vermont policies & programs should be modified to balance State energy policy and related goals outlined in the 2022 Comprehensive Energy Plan.
- A report on the process, including:
    - A summary of the public engagement conducted (for example, how it was conducted, who was engaged, what ideas, concerns, considerations emerged)
    - The results of technical analyses conducted to assess potential policy or program changes and their tradeoffs with respect to core considerations like equity, cost-effectiveness, carbon impact, grid impact, and economic development.
    - Completed equity impact assessments for relevant programs, policies, and/or recommendations

The process will kick off in late January 2023 with a webinar series aimed at developing a common understanding around Vermont's existing electric system and the policies and programs that support it. The content of these webinars will be informed in part by responses to the RFI topic three ("what issues should be addressed"), which highlighted a number core issues or questions to consider over the coming year. These included:

- What resources and/or technologies should or should not be eligible under an updated renewable or clean energy standard (e.g., hydroelectric, nuclear, storage, solar, wind)?
- Where those resources should be located (e.g., within Vermont or the New England region more broadly)?
- How equity related considerations around meaningful engagement of communities, affordability, and access to renewable energy resources through various programs (ex. net metering) might be advanced?
- The need to assess resources related to issues like cost-effectiveness, greenhouse gas reduction potential and additionality, equity, etc.

2.1.2 Electricity Prices

World events have caused significant spikes in the price of many fuels, including natural gas. Natural gas generating facilities generally set the wholesale price of electricity in the ISO New England (ISO-NE) marketplace which serves Vermont utilities. The figure below shows the wholesale price of electricity for the Vermont zone, increasing significantly over the last year.

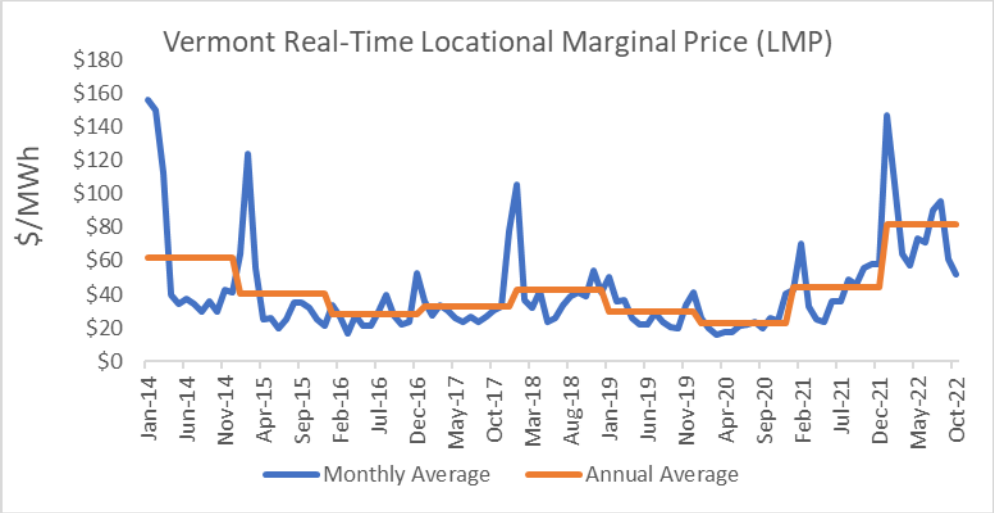


Figure 5: Vermont Real-Time Locational Marginal Price for Electricity

Generally, Vermont uses a regulated electric utility structure, whereby utilities remain "vertically integrated" and are responsible for supply, transmission, and retail services to end-use customers. Unlike some other states, where power generation and supply roles are managed separately from distribution services, Vermont utilities are allowed to meet their supply needs through long-term contracts. As a result, contracts secured before the price spike insulate Vermont customers from some of the short-term market impacts. As shown by the figure below, Vermont's prices have risen over the last year, albeit much more slowly and steadily than other Northeastern states.

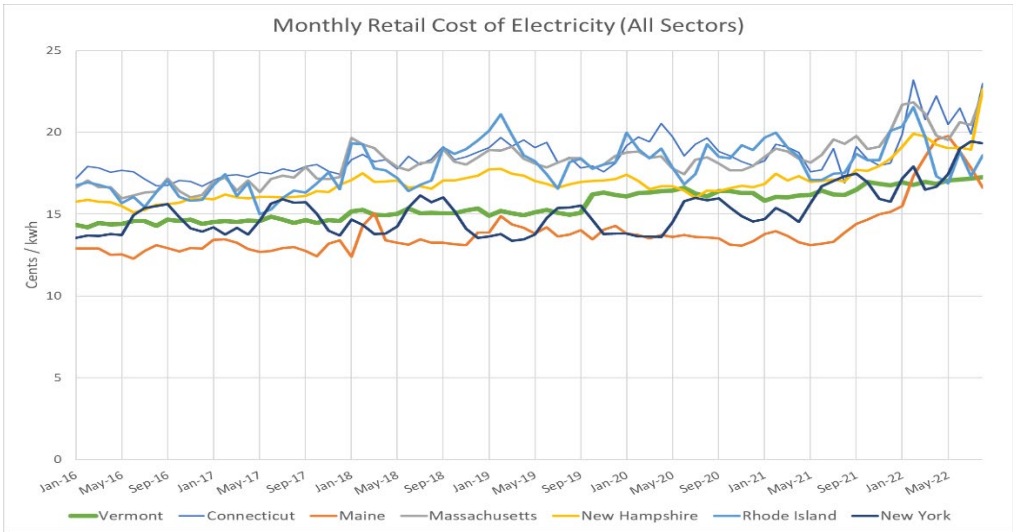


Figure 6: New England and New York Average Retail Electricity Prices, 2016-2022

Vermont customers do see some impact when all of a utility's power needs are not secured well in advance. In addition to these market price increases, inflationary pressures have contributed to recent requests for rate increases by Vermont's utilities. Burlington Electric Department,

Vermont Electric Cooperative, Washington Electric Cooperative, Stowe Electric Department, Village of Enosburg Falls Inc., and Morrisville Water and Light Department have recently requested Public Utility Commission (PUC) permission to increase rates. Green Mountain Power and Vermont Gas Systems both have Alternative Regulation Plans where market-related power supply costs are passed-through to customers using a quarterly adjustment mechanism; customers of these companies have seen rates reflect these regional prices.

2.1.3 Winter Fuel Security

Over the past decade, many coal, oil, and nuclear generating units have been retired from ISO New England's system, increasing the reliance on natural gas a generating resource. Natural gas pipeline import capability in New England can become constrained in the winter as gas for electricity generation competes with demand for heating purposes in other New England states. (Vermont Gas is supplied by a Canadian pipeline and load does not impact the New England electricity prices.) Delivery of heating fuel is usually done under "firm" service—in other words, it is guaranteed—while electric generating plants secure supply under interruptible contracts in order to keep prices low year round. As a result, when there is a prolonged cold snap and home heating requires more natural gas, New England risks electric supply shortages.

It is possible for New England to import liquified natural gas (LNG) through three terminals, the Saint John terminal in New Brunswick and two terminals near Boston. Recently, owners of the Everett terminal near Boston and the connected Mystic generating station sought to retire both facilities. After studying the potential retirement, ISO-NE determined that it would exacerbate the winter fuel supply issue and leave the region in an untenable operating position should adverse winter conditions come to pass. As such, the Mystic plant and Everett terminal were retained under a cost-of-service agreement that has incurred considerable cost to ratepayers, but which has contributed to ISO-NE's projection that under all conditions except for a severe cold snap that there will be adequate fuel supply for winter 2022-2023. In the meantime, the Department of Public Service has encouraged utilities to convene a winter reliability task force. This task force has met and developed procedures and policies to mitigate impacts from any potential fuel shortages in New England.

For the upcoming two winters of 2023-2024 and 2024-2025, FERC has approved the filing for an Inventoried Energy Program (IEP) that will provide extra financial incentive to resources that are able to store more fuel than might otherwise be economic to increase the fuel security posture of the region. A subsequent court decision, however, necessitated the removal from the IEP of several types of resources that were not likely or scarcely able to change their decision-making on stored fuel to benefit reliability, including coal, hydro, biomass, and nuclear. It remains to be seen what impact this program will have on fuel security.

2.1.4 Offshore Wind

The development of wind resources off the shores of New England has the potential to help New England states meet its renewable and clean electricity targets, while mitigating fuel security issues discussed in Section 2.1.3 above. With significant new generating capacity being considered, states have been discussing the onshore transmission infrastructure that may be

necessary to deliver supply from these resources. To better understand the necessary development of transmission projects, as well as costs and potential impacts, a Request for Information (RFI) was issued by five New England States (with Vermont as an observer) on the proposal of a "Modular Offshore Wind Integration Plan."[13] Vermont's status as an observer reflects its differences from the region—its regulatory structure, where it remains vertically integrated with its electric utilities able to enter into long-term contracts with developers and seek their approval from the Public Utility Commission—and the fact that Vermont has no coastline. Though Vermont is not a direct issuer of the RFI, Department of Public Service officials have been involved in its planning and development, and will continue to be involved in review of the RFI responses. If it is appropriate given its regulatory structure, Vermont can still join any potential Request for Proposals that would follow the RFI.

2.1.5 Generation Constraints

Despite its small size, Vermont has experienced a high rate of growth in distributed energy resources, specifically in the deployment of solar installations. Having seen almost 50 megawatts (MW) of small-scale solar installations each year for the better part of the past decade, and with total capacity now about 400 MW, there are certain parts of the Vermont grid that are saturated with generation resources. Particularly in western Vermont, several distribution substations are no longer able to accommodate the connection of additional distributed generation resources above a certain size. Reverse power flow from these resources would exceed utility system equipment ratings.

The most significant generation constraint in Vermont remains in the northern part of the state, in an area referred to as the Sheffield-Highgate Export Interface. Utility-scale generation within this interface is subject to limits and curtailment by the ISO-NE system operator to maintain system reliability. Because northern Vermont is very rural, the transmission infrastructure there was built to handle the relatively small amount of load that exists there. In contrast, the region contains or is adjacent to several hundred megawatts of generation, consisting mostly of wind, small-scale hydro, and hydro imported from Quebec via a back-to-back high voltage DC facility. Because Vermont's distribution utilities are vertically integrated, and some Vermont utilities hold ownership or are major off-takers of wind plants within the SHEI that are subject to periodic curtailment, Vermont ratepayers have experienced financial burden from these conditions. Accordingly, Vermont utilities are coordinating to increase grid capacity through a small portfolio of cost-effective projects to mitigate curtailments.

2.1.6 Ryegate Contract Extension

Ryegate is a 20 MW biomass (wood-fired) generator that qualifies for Vermont's Baseload Renewable Energy Standard. Under 30 V.S.A. § 8009, utilities must purchase their pro rata share of the output from Ryegate under a 10-year contract administered by VEPP, Inc. The current contract was set to expire November 1, 2022; however, Act 155 (S. 161) of 2022 temporarily extended this obligation for two years and also created an opportunity for a further extension out

13 https://newenglandenergyvision.com/new-england-states-transmission-initiative/

to 2032 provided that Ryegate owners make improvements to the plant's efficiency. The fate of this facility is not yet known and contingent on improved heat utilization for beneficial purposes (also known as co-generation).

As a wood-fired plant, the Ryegate facility relies upon a consistent supply of biomass from the forest economy. Likewise, many fuel suppliers rely on Ryegate to fill an essential role in the market for forest products, a market with significant impacts on businesses and livelihoods. Several fuel suppliers have recently expressed significant concerns about the state of operations at the Ryegate facility. The most prominent issues include (1) payment and contracting practices, with some commenters reporting that they are not being paid for deliveries or are owed substantial sums; (2) lack of a certified scale to weigh incoming deliveries; (3) lack of qualified forestry staff; and (4) the impacts of ongoing bankruptcy proceedings associated with Solar Enterprises, Series LLC ("Stored Solar"), Ryegate's owner. The Department has engaged with Ryegate since learning of these issues to express its concern and underline the importance of addressing the issues, fully and transparently, without delay. Ryegate has acknowledged that it had been behind on payments, and faced difficulties with its payment schedules, but reported that it was current on its outstanding obligations through November 13, 2022. The company also expressed a willingness to enter contracts with suppliers, which had been a standard practice in the past. As to equipment and staff, Ryegate stated that its broken truck scale was due to be repaired and recertified on November 29, and confirmed it has a Vermont-licensed forester with plans for a successor. Ryegate also represents that it is not directly involved in the bankruptcy case, although the proceeding has indirectly affected its operations. There is still significant progress to be made on several fronts, and Ryegate has affirmed its commitment to continuing the work. The Department will continue to closely monitor Ryegate's operations under the contract that has been directed by the General Assembly.

2.1.7 Data Organization and Transparency

Section 2.2.1.3 of the 2022 Comprehensive Energy Plan spoke to the critical role data plays in the energy planning process. This ranges from understanding the context in which programs and policies operate, to modeling and analyzing how to achieve renewable energy and climate objectives, and monitoring and assessing progress towards reaching those goals. In recognition of this role, the Department of Public Service has been engaged in an effort alongside numerous stakeholders like the Energy Action Network, the distribution and efficiency utilities, and regional planning commissions, among others, to modernize its data infrastructure and develop a sustainable platform to transparently report on and share data on Vermont's energy system and progress towards meeting state energy objectives. This project has focused on several key objectives:

- Modernize and streamline data collection undertaken by the Department to reduce reporting burdens on implicated stakeholders;
- More efficiently and explicitly manage the data collected by the Department to make it more accessible for internal Departmental planning and regulatory needs; and,
- Provide transparent and objective data to the public through a centralized repository and accessible dashboard able to communicate Vermont's progress towards meeting

CEP objectives and supporting a variety of statewide energy planning and policymaking efforts (e.g., meeting clean energy and equity-related goals).

Over the past three years, the Department has taken several key steps to advance this effort. This includes conducting an effort to review and map energy data flows in the electric sector and working with the state's Agency of Digital Services to identify and document project workflows and core business and technical requirements to support the Department's efforts to streamline energy data collection and management and launch a public dashboard. In late 2022, the Department of Public Service proposed a State Energy Program allocation of $150,000 to support the development of this infrastructure based on the technical specifications developed alongside the Agency of Digital Services. The Department aims to develop a workplan and timeline for development in early 2023 and expects this work will be developed in coordination with the Measuring and Assessing Progress tool required by the Global Warming Solutions Act to assess progress towards meeting the Vermont's climate goals related to emissions reductions, resilience, and equity. Such coordination will be critical to ensure streamlined data reporting and analysis.

2.2 Electricity Demand

The following sections provide data and information on the electricity demand and on select programs that impact demand.

2.2.1 Historic and Forecast Annual and Peak Demand

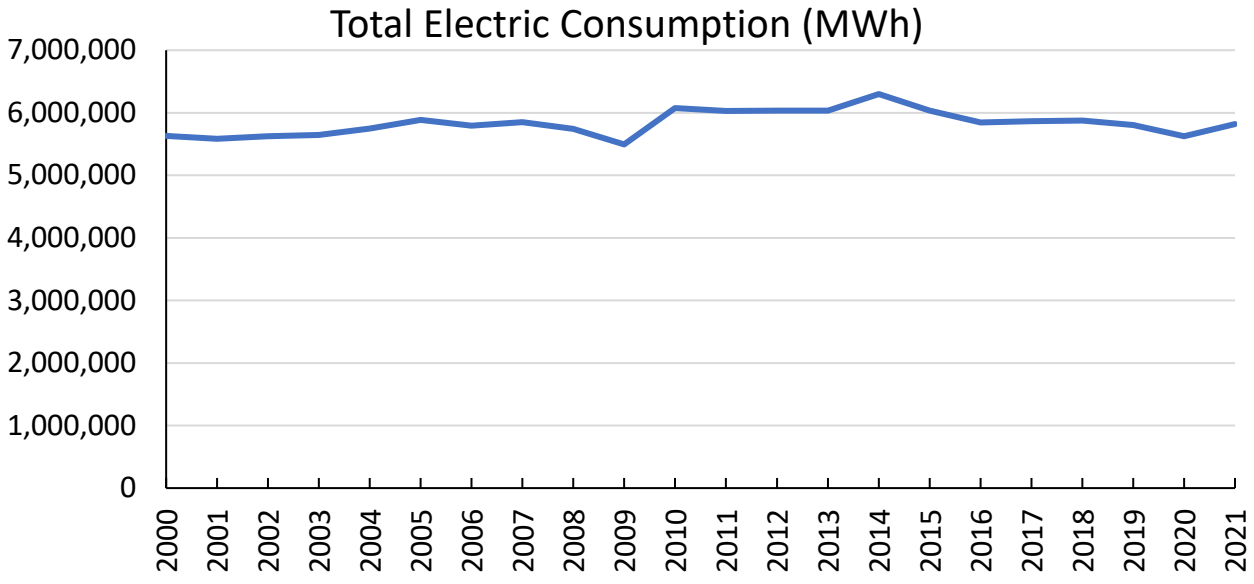


Figure 7: Vermont Annual Electricity Consumption

ISO-NE System					Vermont		
Year	Peak Date	Hour Ending	System Peak Load (MW)	Vermont Coincident Peak (MW)	Peak Date	Hour Ending	System Peak Load (MW)
2016	8/12/2016	15:00	25,111	868	1/4/2016	18	931
2017	6/13/2017	17:00	23,508	849	12/29/2017	18	942
2018	8/29/2018	17:00	25,559	726	7/2/2018	20	935
2019	7/30/2019	18:00	23,929	837	1/21/2019	18	892
2020	7/27/2020	18:00	24,727	792	7/27/2020	20	890
2021	6/29/2021	16:00	25,280	825	8/26/2021	20	962
2022*	*8/4/2022*	*17:00*	*24,471*	*761*			

Figure 8: Historical ISO-NE and Vermont System Peak Demand
*Preliminary data for 2022

The figure above shows forecast annual demand scenarios developed for purposes of the Annual Renewable Energy Standard Report detailed in Appendix B. The baseline forecast references the forecast developed for the 2021 VELCO Long-Range Transmission Plan, with modifications to represent more recent data. This "Central Mitigation Scenario" forecast uses assumptions associated with modeling performed for the Comprehensive Energy Plan and Climate Action Plan to meet greenhouse gas reduction requirements. For more detail, see Appendix B.

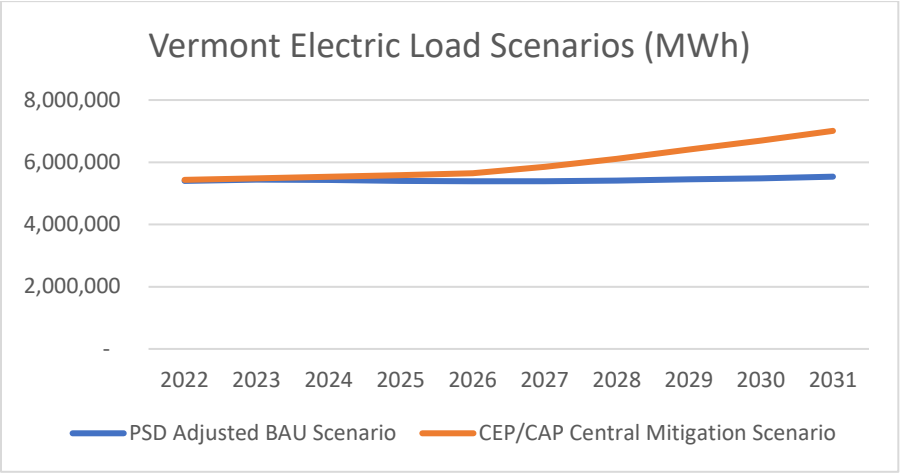


Figure 9: Projected Vermont Annual Energy Consumption Scenarios

The peak demand for electricity forecast below is provide directly from VELCO's Long Range Transmission Plan, with no updates (unlike the annual consumption scenario, above).

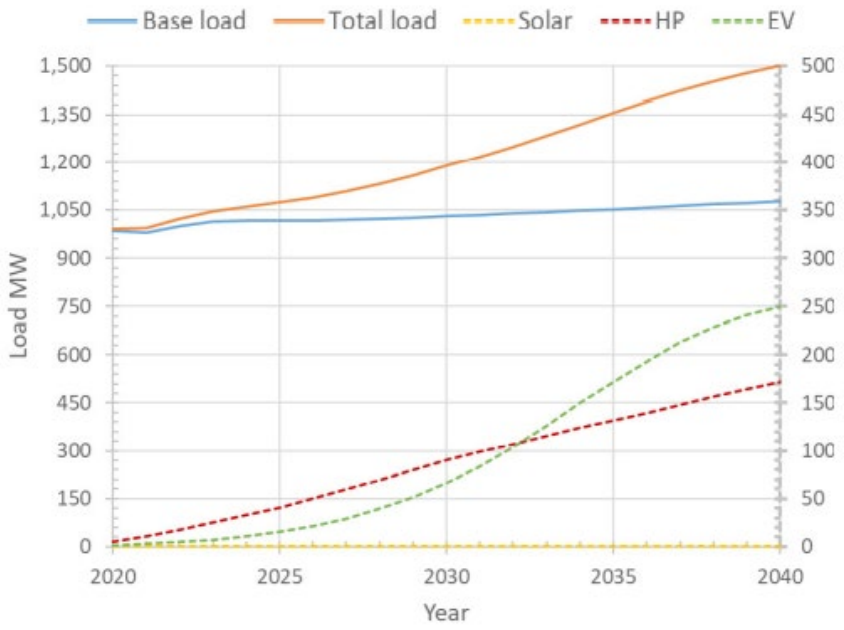


Figure 10: Projected Vermont Winter Peak Load and Component Forecasts[14]

The base and total load lines use the scale to the left. The dashed lines for solar photovoltaics (PV), heat pumps (HP), and electric vehicles (EV) use the scale to the right.

2.2.2 Electric Energy Efficiency

Since 2000, Vermont's energy efficiency utilities (EEUs) have acquired significant electric efficiency resources that have met a significant portion of Vermont's electric needs, at a lower cost than supply resources. Figure 11 shows Efficiency Vermont (EVT) cumulative savings over time, while Figure 12 illustrates the results of Burlington Electric Department (BED) efforts.

[14] VELCO 2021 Long-Range Transmission Plan, p. 21. https://www.velco.com/our-work/planning/long-range-plan.

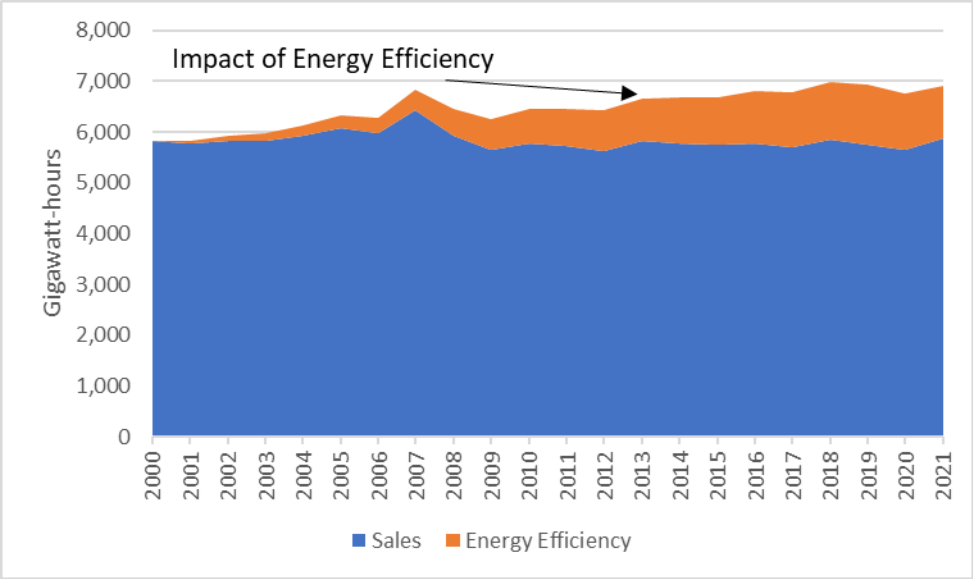


Figure 11: EVT's Electric Energy Efficiency Impacts

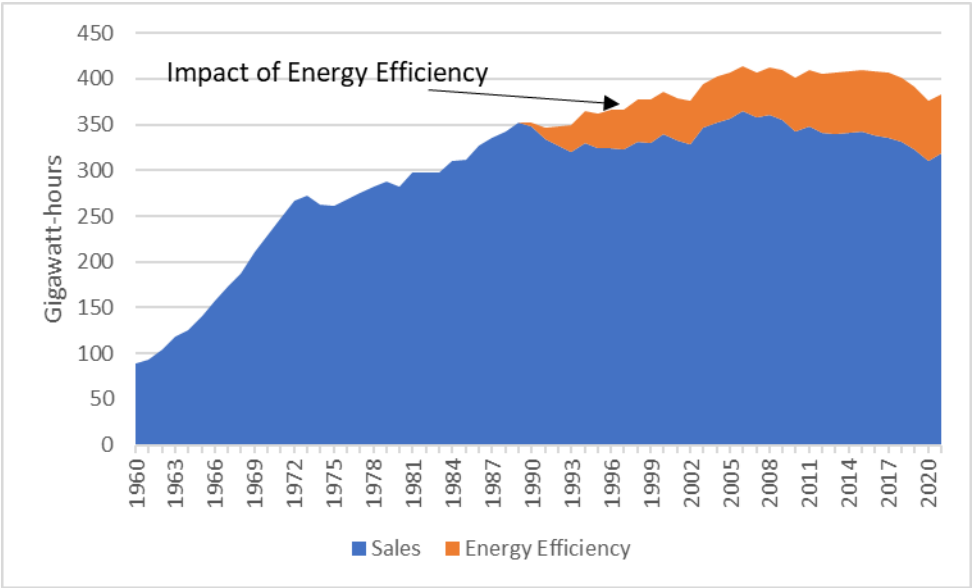


Figure 12: BED's Electric Energy Efficiency Impacts

The Public Utility Commission sets EEU budgets to acquire "all reasonably available cost effective" electric efficiency, pursuant to 30 V.S.A. § 209(d) and least-cost planning principles of 30 V.S.A. § 218c. For Efficiency Vermont, the Commission ordered a statewide electric energy efficiency budget of approximately $45,600,000 annually. For the Burlington Electric Department, the electric energy efficiency budget is approximately $2,600,000 annually.[15]

[15] The energy efficiency utilities are currently operating under the 2021-2023 performance period Demand Resource Plan budgets and performance goals approved by the Public Utility Commission in Case 19-3272-PET.

	2021	2022	2023	Total
EVT Electric Efficiency	$45,583,399	$45,719,158	$45,769,989	$137,072,546
BED Electric Efficiency	$2,661,737	$2,571,530	$2,631,882	$7,865,149
Total	**$48,245,136**	**$48,290,688**	**$48,401,871**	**$144,937,695**

Figure 13: EVT and BED Electric Efficiency Budgets

The Public Utility Commission has opened a docket (Case 22-2954-PET) to determine the budgets for both energy efficiency utilities (as well as Vermont Gas efficiency programs) for the 2024-2026 performance period. As a part of this process, the Department commissioned an updated Energy Efficiency Potential Study.

The scope of this study distinguishes three types of energy efficiency potential: (1) technical, (2) economic, and (3) achievable. Technical potential is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness (including measure costs and program delivery costs) and the willingness of end users to adopt the efficiency measures. Economic potential refers to the subset of the technical potential that is economically cost-effective as compared to conventional supply-side energy resources. Achievable Potential considers real-world barriers to encouraging end users to adopt efficiency measures. The analysis provides two scenarios of achievable potential, maximum and program achievable. Maximum achievable potential is the amount of energy use that efficiency can realistically be expected to displace, assuming the most aggressive program scenario and incentives possible and program achievable potential which estimates achievable potential on EEUs paying incentive levels (as a percent of incremental or total measure costs) that are calibrated to historical levels.

The efficiency potentials for both Efficiency Vermont (Figure 14) and Burlington Electric Department (Figure 15) decrease during the first decade of the forecast, largely reflecting the impact of legislation (Act 120 of 2022) addressing commercial lighting and the increased pace of retrofitting four-foot lamps containing mercury. (These will be replaced with LEDs.) The rise in savings potential later in the forecast reflects renewed savings opportunities from measures adopted early in the forecast after they need replacement.

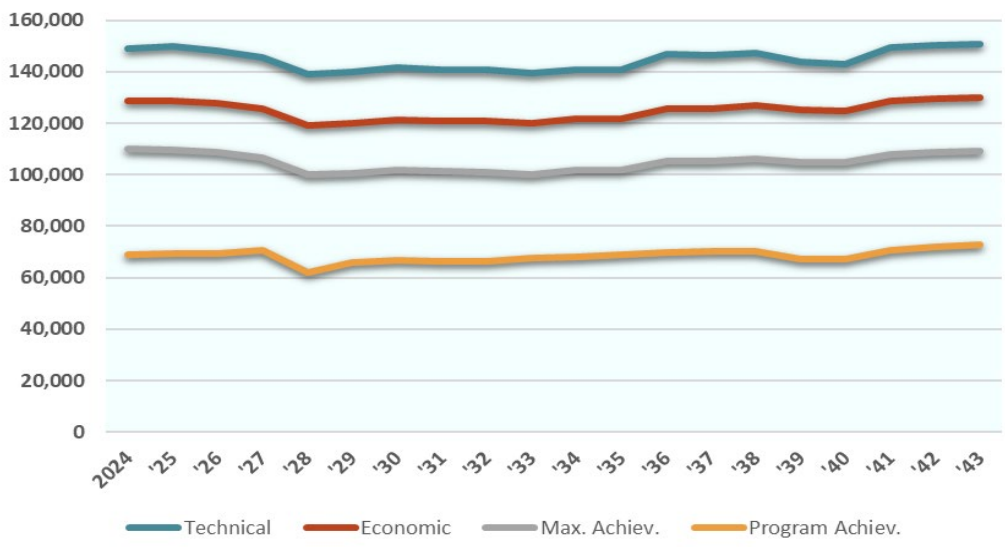


Figure 14: EVT Potential Incremental Annual MWh Savings[16]

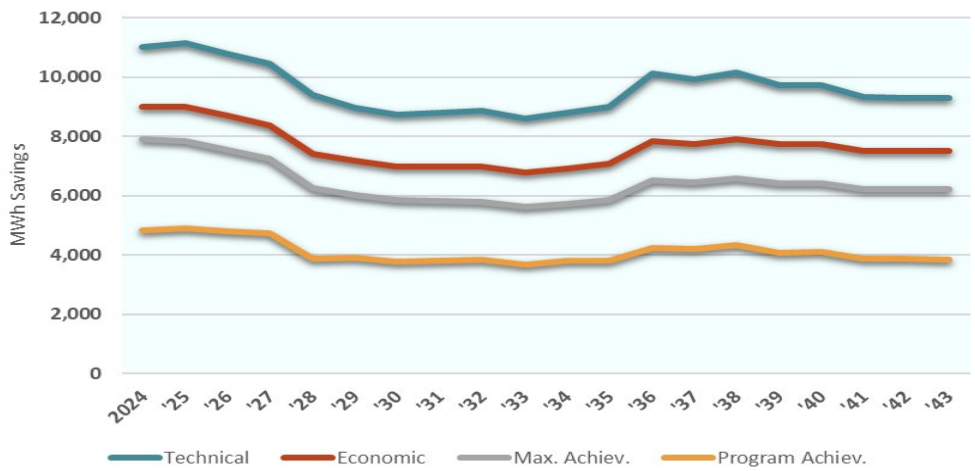


Figure 15: BED Potential Incremental Annual MWh Savings[17]

2.2.3 Electrification - Heat Pump Forecast

Figure 16 below shows both historical and forecasted cumulative and annual cold climate heat pump (CCHP) installations for the state. The forecast represents high efficiency CCHP units supported by EVT and BED efficiency programs (including units supported by DUs through Tier III programs). Not included in the figures below are a forecast of approximately 10,600 units which represent less efficient, lower tier, CCHP units assumed to be increasingly available in the

[16] Results from Energy Efficiency Potential Study prepared by GDS Associates, Inc., for PUC Case 22-2954-PET.
[17] Results from Energy Efficiency Potential Study prepared by GDS Associates, Inc., for PUC Case 22-2954-PET.

market but not energy efficient enough to be supported by EEUs.[18] Starting in 2024, on an annual basis, the number of new CCHP installations reaches approximately 13,000, then gradually increases to peak at 20,700 in 2030 and tapers gradually to 7,200 in 2043.

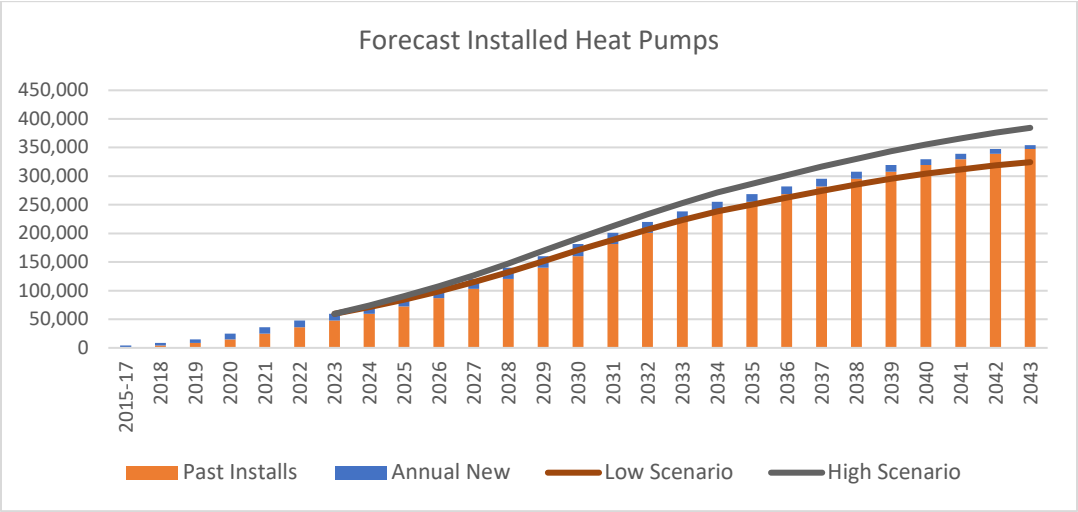


Figure 16: EVT and BED Cold Climate Heat Pump Forecast

2.2.4 Load Management

Flexible load management (FLM) is an essential tool for managing the power supply costs and grid impacts related to the deployment of distributed energy resources (DERs), such as electric vehicles (EVs). The 2021 VELCO Long-Range Transmission Plan, for instance, calls for managing 75% of EV charging load during peak periods, to maintain reliability without building expensive new transmission infrastructure (by keeping statewide loads under 1,470 MW in winter and 1,210 MW in summer). Many utilities have or are currently implementing load management programs; more detail on progress toward flexible load management initiatives in 2022 can be found in Appendix A.

As part of planning for the management of flexible loads, it is essential for utilities to project the type, location, size, and other characteristics of future DERs, including those adopted by customers outside of utility offerings such as Tier III programs. And then, utilities must also develop technology deployment plans to accommodate and manage the expected demands from these DERs. The Department's updated Integrated Resource Plan (IRP) guidance, expected to be available in early 2023, will include detailed recommendations on depicting initiatives and technology deployment flowcharts related to FLM.

One tool in the load management toolbox is the deployment of battery storage. Vermont utilities have approximately 66MW of battery storage either interconnected or proposed. As more storage

[18] The forecast is a product of the Department's 2022 Energy Efficiency Potential Study filed in PUC case number 22-2954-PET. The forecast was prepared before tax credit changes under the Inflation Reduction Act.

is deployed (both utility- and residential-scale) it will be imperative for utilities and others to carefully consider where units are located and how to best deploy capacity to ensure the greatest benefit of ratepayers.

2.3 Electricity Supply

The following sections provide data and information on the supply of electricity and includes information regarding compliance with the Renewable Energy Standard. Many details regarding the supply of renewable electricity can be found in the Renewable Energy Standard program report, included as Appendix B to the Annual Energy Report.

2.3.1 Vermont Power Supply Mix

Figure 17 shows Vermont's power supply portfolio based on contractual or ownership entitlements without regard for disposition of Renewable Energy Credits (RECs). Figure 18 shows Vermont's electric power portfolio after accounting for the purchase and sale of RECs.

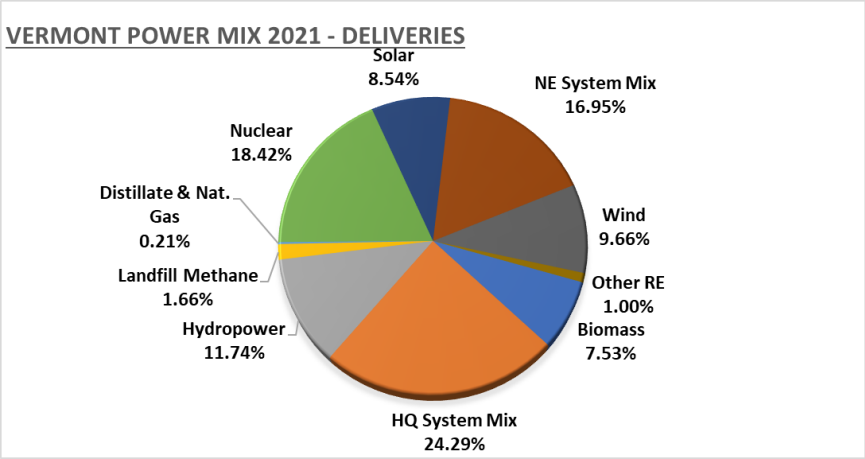


Figure 17: Vermont's 2021 Electric Power Mix Based on Physical Deliveries

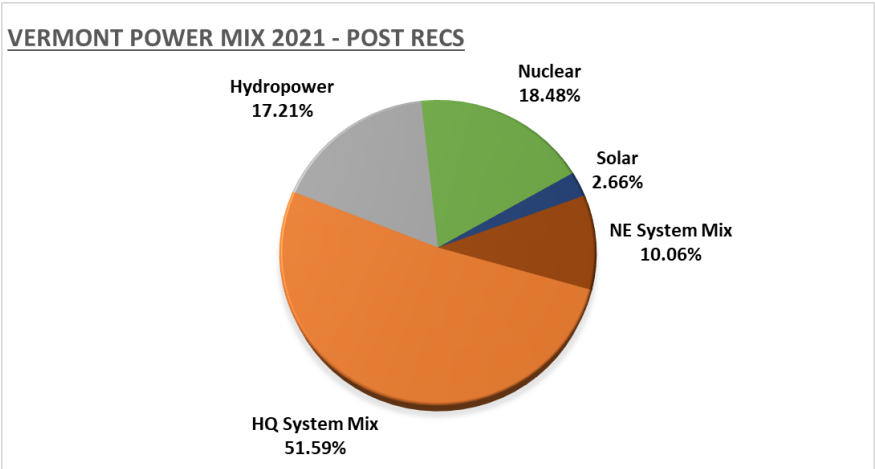


Figure 18: Vermont's 2021 Electric Power Mix After REC Retirements

Since the implementation of the Renewable Energy Standard (RES) in 2017, Vermont utilities have had to meet a certain percentage of their **retail sales** from qualifying renewable electricity resources. From 2017-2020, Vermont reported it's "Post-RECs" fuel mix based on renewable energy certificate retirements, as a percent of retail sales. However, this practice did not account for transmission and distribution line losses from the generating source to the customer's meter where retail sales are measured (a small amount of utility own-use was also unaccounted for). Utilities must purchase more energy than their retail sales in order to serve that load. Those purchases are now accounted for, and assumed in this reporting to be ISO New England system mix, because no other attributes have been retired. This update is now reflected in the reporting for Vermont's Greenhouse Gas Inventory (discussed in Section 1.3). After accounting for these additional purchases, Vermont's electric mix was still approximately 90% carbon free compared to less than 50% in 2016 (the year before RES took effect).

2.3.2 Standard Offer and Net Metering Installations

Additional information on the Standard Offer and Net Metering programs can be found in Appendices B and C.

A total of 80.3 MW of Standard Offer renewable projects have been commissioned as of October 20, 2022. An additional 51.8 MW of projects have been awarded contracts through prior solicitations but have not yet been commissioned.

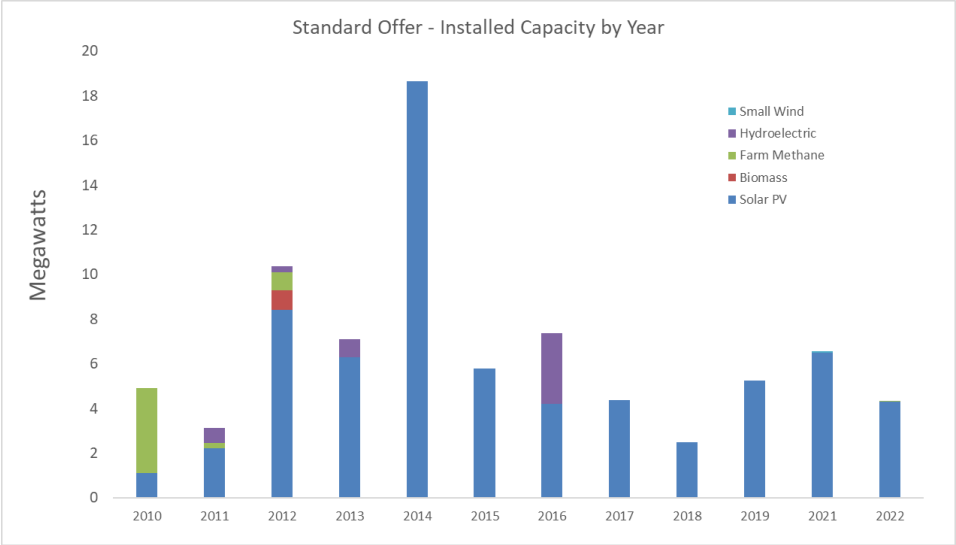


Figure 19: Installed Standard Offer Capacity Annually

Well-over 300 MW of solar has been installed by the Net Metering program.

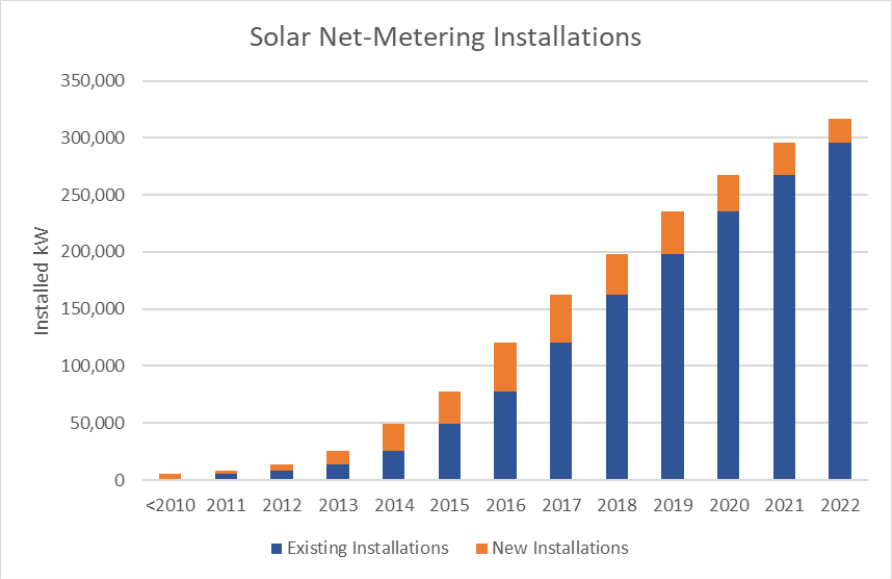


Figure 20: Solar Net-Metering Installations[19]

2.3.3 Renewable Energy Standard Requirements

Vermont's Renewable Energy Standard increases to 75% renewable by 2032, with at least 10% coming from Tier II Distributed Renewable Generation (consisting of generators under 5 MW, located in-state, and commissioned after 2016).

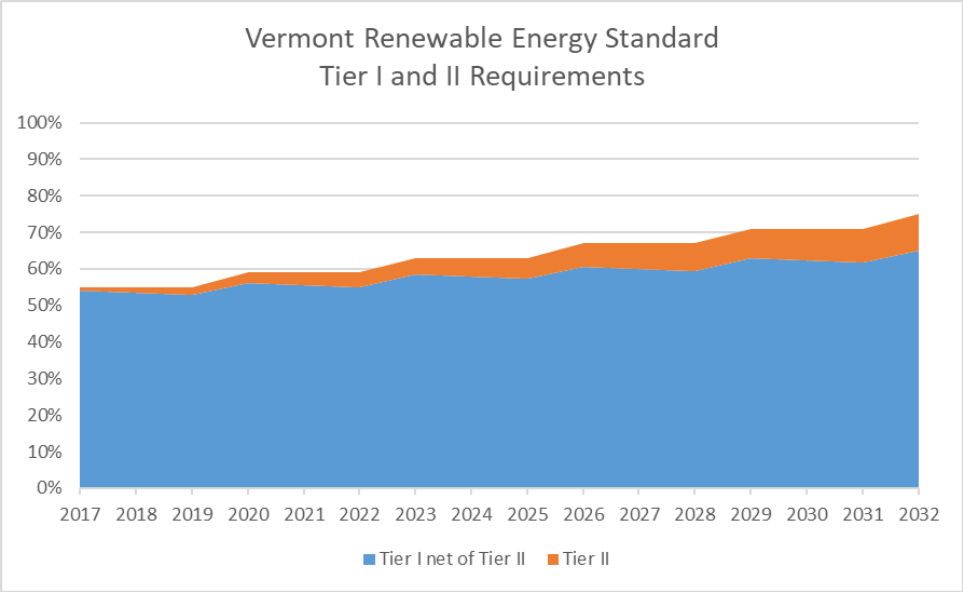


Figure 21: Tier I and II Renewable Energy Standard Requirements

[19] GMP, BED and VEC data are all shown through October 2022; VPPSA and WEC shown through September 2022, HPE and SED updated through 2021

Vermont's Renewable Energy Standard requires electric utilities either procure additional renewable distributed generation eligible for Tier II or acquire fossil fuel savings from energy transformation projects reaching 12% of retail electric sales by 2032.

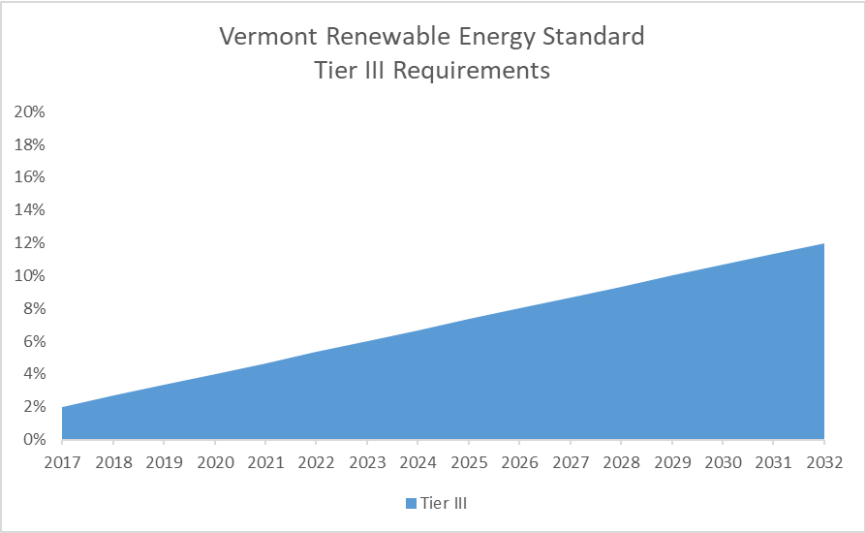


Figure 22: Vermont Tier III Requirements

2.3.4 Renewable Energy Standard Compliance

Figure 23 provides an overview of 2021 RES compliance by Tier for each utility in the state. Figure 24 shows the resources used for compliance.

Utility	2021 REC Retirements and Savings Claims as Percent of Sales		
	Tier I	Tier II	Tier III[20]
Barton	65.3%	3.4%	5.3%
Burlington	102.6%	0.0%	7.3%
Enosburg Falls	65.3%	3.4%	5.3%
Green Mountain Power	78.8%	3.4%	4.7%
Hardwick	65.3%	3.4%	5.3%
Hyde Park	59.0%	3.4%	3.3%
Jacksonville	65.3%	3.4%	5.3%
Johnson	65.3%	3.4%	5.3%
Ludlow	65.3%	3.4%	5.3%
Lyndonville	65.3%	3.4%	5.3%
Morrisville	65.3%	3.4%	5.3%
Northfield	65.3%	3.4%	5.3%

[20] Washington Electric Cooperative and Hyde Park used Tier II RECs for part or all of their Tier III compliance. These RECs are counted towards their Tier III obligation and not their overall renewability as measured in Tier I/II

Orleans	65.3%	3.4%	5.3%
Stowe	59.0%	3.4%	7.5%
Swanton	100.0%	0.0%	5.3%
Vermont Electric Cooperative	59.0%	3.4%	8.7%
Washington Electric Cooperative	107.1%	3.4%	11.4%
Vermont Total	**77.7%**	**3.2%**	**5.3%**

Figure 23: Renewable Energy Standard Compliance

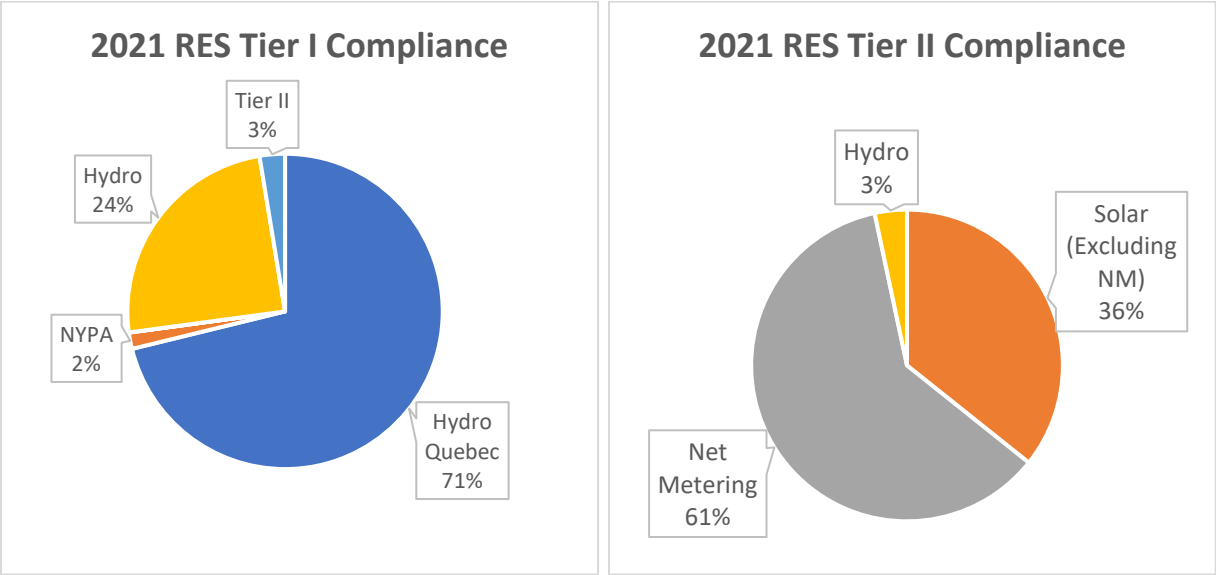


Figure 24: Renewable Energy Standard Tier I (Left) and Tier II (Right) Compliance[21]

Vermont utilities met their Tier III obligations with a variety of measures. Over 50 percent of Tier III savings were derived from cold climate heat pumps.

[21] Tier II is a component of Tier I and many Vermont utilities over-comply with Tier I.

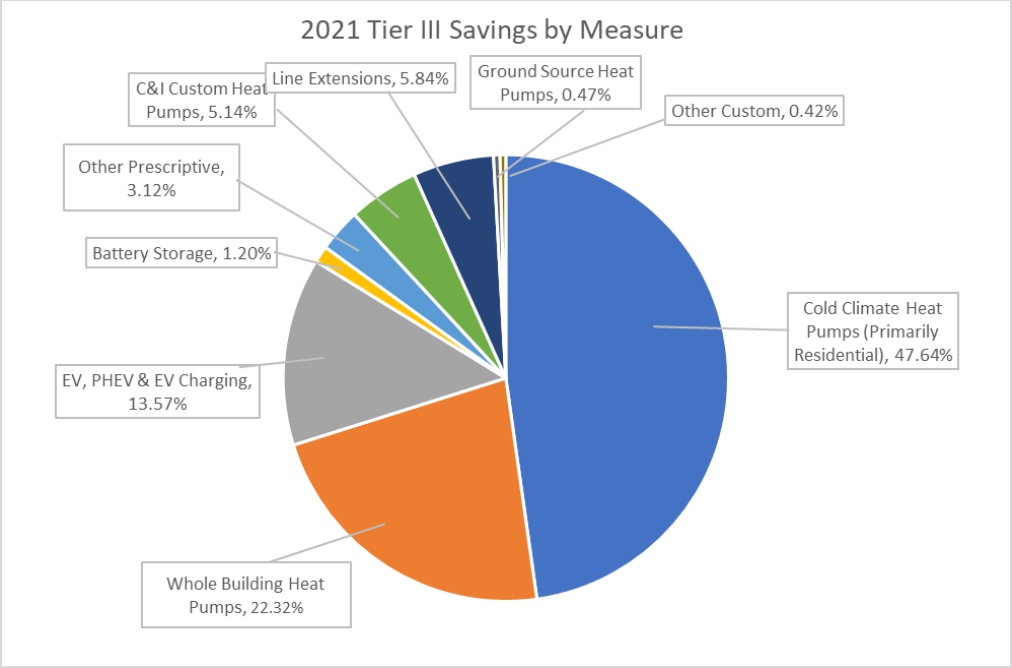


Figure 25: 2021 Renewable Energy Standard Tier III Compliance

2.4 Renewable Energy Credit Prices

Massachusetts Class I renewable energy credit (REC) prices are a useful measure of the value of Tier II RECs from new renewable generation in Vermont. Most utilities have excess Tier II RECs that can be sold into other state's regional compliance markets.

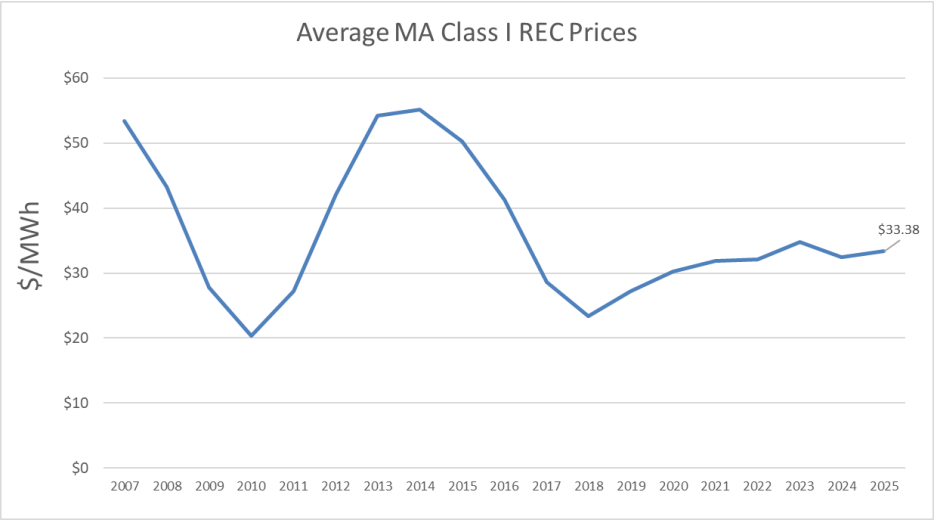


Figure 26: Average Massachusetts Class I REC Prices

Maine Class II REC prices are a useful measure of the value of Tier I RECs from existing renewable generation. Prices have recently increased due to regional demand for compliance with other state clean energy standards.

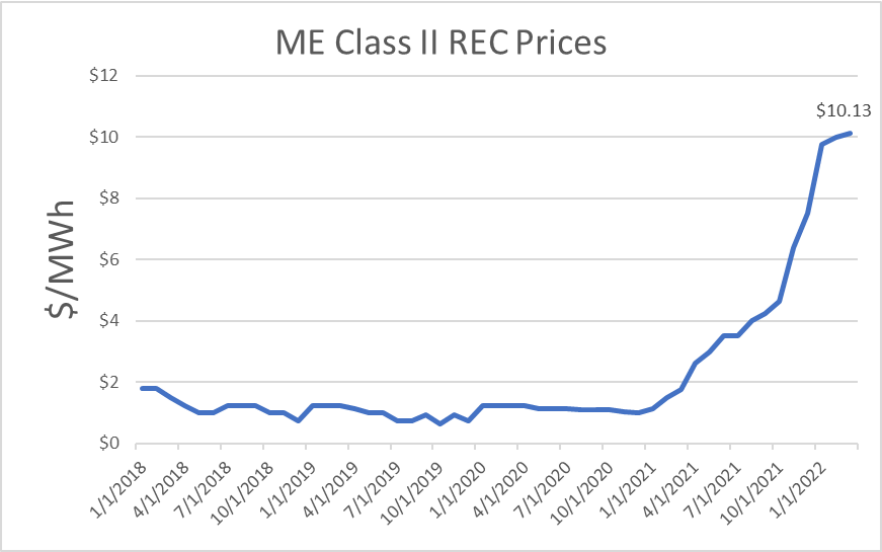


Figure 27: Maine Class II REC Prices

Transportation

Section 3 of this Annual Energy Report covers the Transportation sector. Section 3.1 highlights major trends and initiatives in the transportation sector, while Sections 3.2–3.4 discuss the transportation fuels used in the state, prices for that fuel, and electric vehicle and charging adoption information. Appendix A describes the progress Vermont has made toward recommendations in the Comprehensive Energy Plan.

3.1 Major Trends and Initiatives

3.1.1 Low Emission Vehicle and Zero Emission Vehicle Rules

Consumer demand and regulatory requirements continue to drive electric vehicle adoption.

In 2022, the Agency of Natural Resources amended Vermont's vehicle emissions rules to require vehicle manufacturers to sell an increasing share of low-polluting vehicles. This amendment adopted California's Advanced Clean Cars II, Advanced Clean Trucks, Low NOx (nitrogen oxides), Heavy-Duty Omnibus, and Phase 2 Greenhouse Gas rules, and included requirements related to vehicle durability standards, warranty provisions, battery state of health standardization, battery labeling, and the availability of repair information to independent repair shops. The December 2021 Climate Action Plan deemed adoption of these rules a high priority action. Vermont first adopted California's vehicle emission standards in 1996, and the Agency amends emissions rules periodically.

The Low Emission Vehicle Rules set standards for emissions of criteria air pollutants and greenhouse gases from on-road vehicles that are delivered for sale or placed in service in Vermont. The Zero Emission Vehicle Rules set standards that ultimately require auto manufacturers to deliver more electric vehicles to Vermont. For example, 100% of sales of new light-duty cars and trucks must be zero-emissions vehicles by 2035. Sales requirements for non-emitting medium- and heavy-duty vehicles must rise to between 40% and 75% of new vehicles, depending on the type of vehicle, between model years 2026 and 2035.

3.1.2 Improving Fast Charging Throughout Vermont

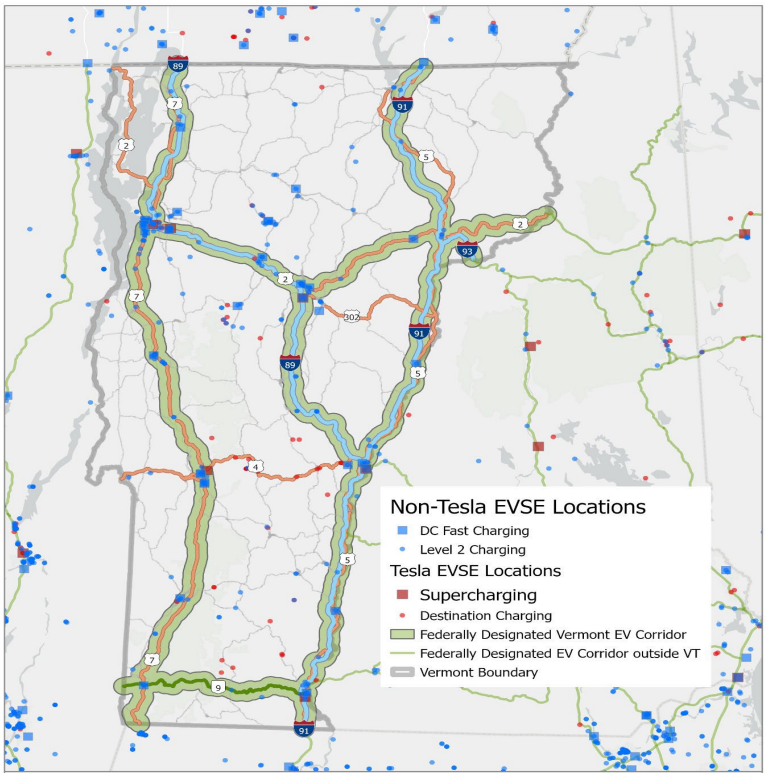
Around 80% of EV charging occurs at home. Ensuring equitable and widespread EV adoption depends on making at-home charging available to all and making fast charging accessible for long-distance travelers.

A recent analysis found that Vermont leads the nation in the number of EV charging ports per capita, a reflection of investments by the state, private businesses and organizations, and certain utilities.[22] State agency efforts to support Electric Vehicle Supply Equipment (EVSE) deployment began in 2014 and continues with Legislative appropriations and Volkswagen settlement mitigation funds.

[22] CoPilot, Inc. November 17, 2022. https://www.copilotsearch.com/posts/states-with-the-most-alternative-fueling-stations.

An interagency working group coordinates state investment in EVSE. This includes ongoing installation of 17 fast chargers along major highway corridors, which—once completed—will ensure that nearly every Vermont resident will live within 30 miles of a fast charger. The federal infrastructure bill, the Infrastructure Investment and Jobs Act, established the National Electric Vehicle Infrastructure (NEVI) Formula Program to provide funding to states for an expanded DC fast charging network. Under NEVI, Vermont will receive $21.2 million through 2026 for additional fast chargers along interstates and major highways.

Fast Charging Corridors and Existing EVSE



Source: VTrans NEVI Plan, August 2022.

3.1.3 Charging at Multiunit Dwellings, Workplaces, and Destinations

Residents of multiunit dwellings, such as apartment buildings and condo complexes, are often unable to charge at home due to practical limitations such as parking areas without electric power. Following an initial $1 million pilot project to support charging station installations at multiunit dwellings, in 2022 the Legislature appropriated $10 million for multiple years of investment in EVSE. At least $3 million will be used to make EV charging accessible at affordable multiunit dwellings. The remainder of the $10 million—up to $7 million—will support charging at workplaces, downtowns, and public attractions, such as parks and museums.

3.1.4 Inflation Reduction Act and EVs

The Inflation Reduction Act significantly altered the existing federal tax credit for new electric vehicles. While the maximum value remains $7,500, the tax credit amount is dependent on where critical minerals are extracted, processed, or recycled, and where battery components are manufactured. Additional vehicle price and income restrictions apply.

Separately, IRA created a new tax credit for used vehicles sold at dealers, valued at $4,000 or up to 30% of the vehicle price. Beginning in 2024, tax credits for both used and new vehicles will be transferrable to others, allow low-income drivers to access the full value of tax credits for the

first time. Additional tax credits now apply to qualifying commercial electric vehicles and to residential and commercial EV charging stations.

3.2 Transportation Fuel Demand

The transportation sector is overwhelming fueled by gasoline and diesel, including small portions of ethanol and biodiesel, respectively. Electricity use for transportation is rapidly growing but remains less than 1% of total fuel use, in part because electric vehicles are more efficient per mile than vehicles with combustion engines.

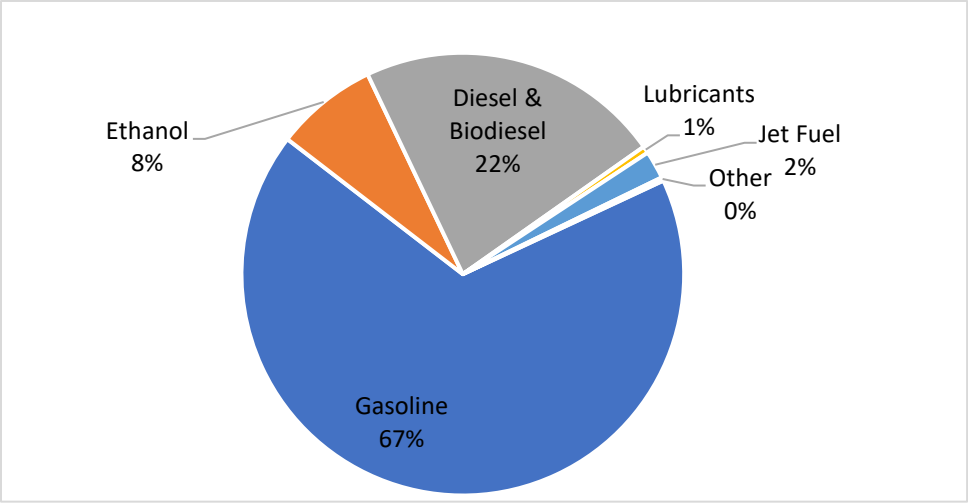


Figure 28: Transportation Energy Consumption by Fuel Type, 2020[23]

Gasoline and diesel sales have decreased slightly between 2012 and 2019 before falling in 2020. Gasoline purchases have not yet returned to level seen before the Covid-19 pandemic.

[23] US Energy Information Administration Estimate (SEDS Table C8) for 2020. "Other" includes electricity, natural gas, and avigation gas.

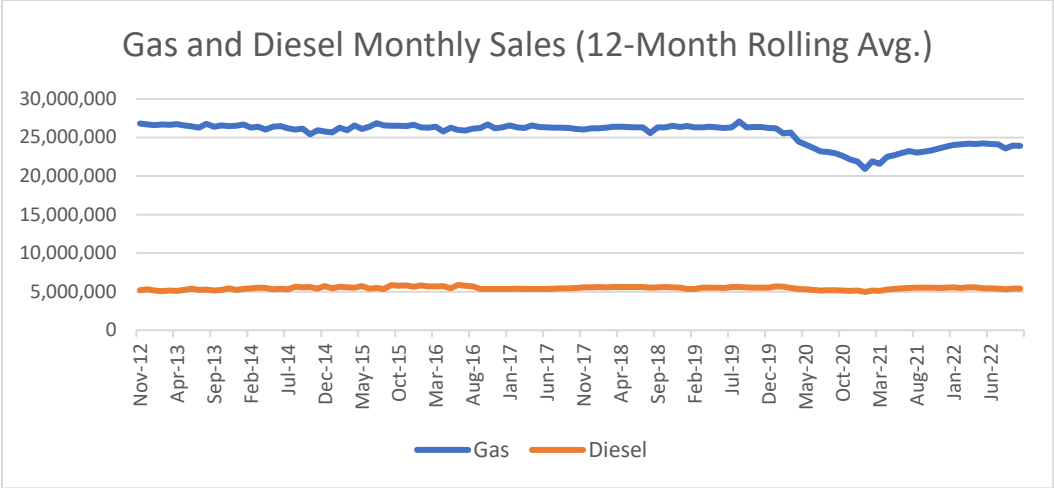


Figure 29: Gas and Diesel Sales, 2012-2022[24]

3.3 Transportation Fuel Prices

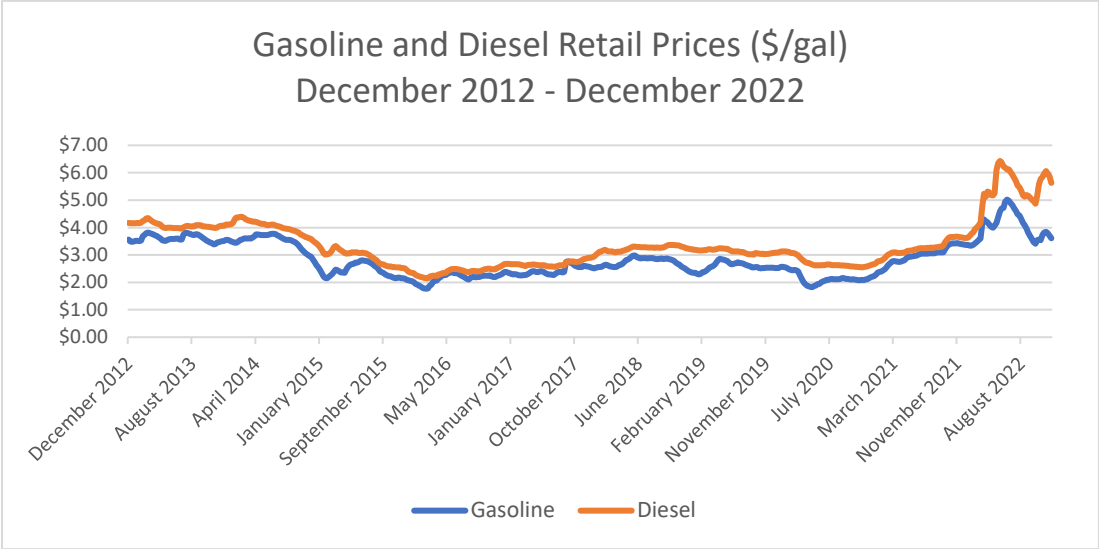


Figure 30: Gasoline and Diesel Fuel Prices, 2012-2022[25]

[24] Vermont Joint Fiscal Office Monthly Updates through October 2022. Non-taxable fuel purchases are excluded.
[25] US Energy Information Administration retail prices for New England, Retail Gasoline (Regular All Formulations) and Retail Diesel (ULSD), through December 5, 2022.

3.4 Electric Vehicle Adoption and Charging

Most Vermont electric customers have access to EV rates that save on at-home charging by shifting vehicle charging away from peak periods. These programs typically use internet-connected Level 2 charging cables to monitor when charging occurs, with discounts offered outside particular hours of the day or outside expected high-cost periods (called "events").

Utility	Standard Rate Above Base Block	Off-Peak Effective EV Rate	Savings	Comment
Burlington Electric Dept.	$0.158815/kWh	$0.086/kWh	46%	Prohibits charging 12 noon to 10 pm to realize lower charging rate each month
Green Mountain Power Rate 72	$0.18035/kWh	$0.14274/kWh	21%	Event-based on-peak charging penalty rate of $0.73388/kWh
Green Mountain Power Rate 74	$0.18035/kWh	$0.13726/kWh	24%	Off-peak occurs outside weekdays, 1 pm to 9 pm
Vermont Electric Coop	$250 one-time bill credit for avoiding on-peak charging (event-based or schedule-based options)			
Vermont Public Power Supply Authority	Free charger and $500 one-time rebate for avoiding on-peak charging (schedule-based)			

Figure 31: Utility Electric Vehicle Tariffs[26]

The pace of EV adoption grows as auto manufacturers offer more electric options for purchase and lease. Among Vermont's EVs, there is a nearly even split between all-electric and plug-in hybrid models.

[26] Utility tariffs as of December 1, 2022. Note: Standard rate is tail block (if applicable), energy-only charge for default residential service. Excludes other charges, such as fixed customer charge and energy efficiency charge. See utility tariffs for details, terms, and conditions.

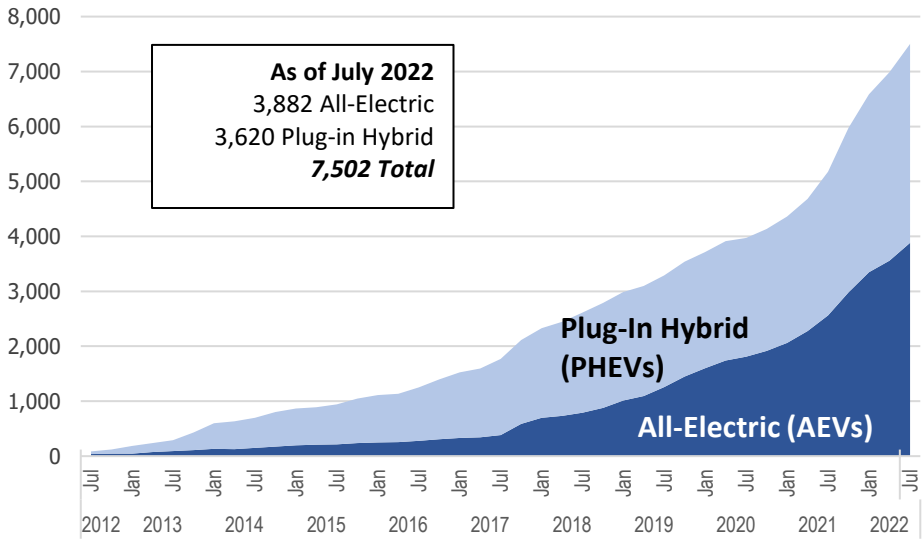


Figure 32: Vermont Electric Vehicle Registrations, 2012-2022[27]

A November 2022 analysis found that **Vermont leads the nation in per-capita EV charging ports**. These include both manufacturer proprietary and open-access locations, although manufacturers appear to moving towards a single common plug shape for the US and Canada.

Rank	State	EV chargers per 100k residents	Total EV chargers	Level 1 chargers	Level 2 chargers	DC fast chargers
1	Vermont	139.7	871	71	725	75
2	California	104.7	41,225	676	33,690	6,817
3	Massachusetts	70.7	4,871	74	4,369	428
4	Colorado	68.5	3,978	89	3,307	582
5	Utah	60.9	1,978	17	1,722	239
6	Rhode Island	59.4	628	82	509	37

Figure 33: Electric Vehicle Charging by State[28]

[27] Courtesy Drive Electric Vermont, with data from Vermont Department of Motor Vehicles registration data processed by VEIC (2012-2013) and Vermont Agency of Natural Resource (2013-2022).

[28] Chart courtesy CoPilot, November 2022, https://www.copilotsearch.com/posts/states-with-the-most-alternative-fueling-stations, using data from US Department of Energy Alternative Fuels Data Center.

Thermal

Section 4 of this Annual Energy Report covers the Thermal Sector. Section 4.1 highlights major trends and initiatives in the sector, while Sections 4.2 and 4.3 discuss the thermal fuels used in the state and prices for those fuels. Section 4.4 discusses the State's weatherization programs. Appendix A describes the progress Vermont has made toward recommendations in the Comprehensive Energy Plan.

4.1 Major Trends and Initiatives

4.1.1 Building Energy Standards

Vermont has both Residential (RBES) and Commercial (CBES) Building Energy Standards, which set minimum efficiency requirements for new and renovated buildings. Building Energy Standards serve to avoid lost efficiency opportunities in long-lived infrastructure, using best-available established technology. They are appropriately applied when cost-effective on a lifecycle basis, locking-in savings for consumers over time.

In April 2022, the Department initiated an extensive public stakeholder engagement process to update Vermont's Building Energy Standards. The Department held two online meetings to gather input from the public for modifying the draft RBES and CBES, attended by builders, architects, multi-family housing developers, low-income housing advocates, electric and gas utilities, energy efficiency utilities, state agency staff (State Historic Preservation Office, Department of Fire Safety), modular home manufacturers, and log home industry representatives. The Department also convened RBES and CBES advisory committees to review technical aspects of the code. The Department modified the proposed RBES and CBES to incorporate changes recommended by the stakeholders and advisory committees. Proposed rules for RBES and CBES were filed with the Interagency for Administrative Rules (ICAR) in September 2022 and with the Secretary of State in October 2022. The Department expects to file the proposed rules with the Legislative Committee on Administrative Rules (LCAR) in January or February of 2023, following additional public hearings held in December. [29]

The adoption of the RBES is expected to save homeowners approximately $900 to $2,000 annually on energy costs, with positive cashflows after investment costs are considered. The adoption of CBES is expected to save commercial building owners approximately $3,800 to $17,000 annually on energy costs, depending on building type and size, with positive cash flow after investment costs are considered.

[29] Code update documents, including proposed rule documents and public hearing transcripts can be found on the Department's webpage at: https://publicservice.vermont.gov/efficiency/building-energy-standards/building-energy-standards-update

4.1.2 Renewable Natural Gas

Vermont Gas Systems has begun incorporating alternative fuel supplies into their portfolio and has set a corporate goal to increase their alternative supplies to 20% of retail sales by 2030, including from Renewable Natural Gas (RNG). RNG can come from many sources including landfills and farms; each source brings different carbon intensity levels. Recently, the Public Utility Commission adopted the Department's position that approval of RNG contracts should reflect the carbon intensity of the source, and keep the cost paid for avoided greenhouse gas emissions below the social cost of carbon.[30]

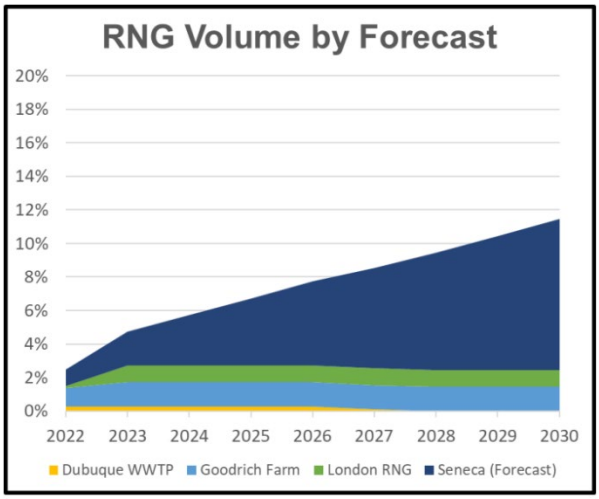


Figure 34: Vermont Gas Alternative Supply Forecast by Source[31]

4.1.3 Weatherization Repayment Assistance Program (WRAP)

The Weatherization Repayment Assistance Program (WRAP) is an innovative new program to help moderate-income Vermonters participate in comprehensive home efficiency projects.

WRAP will allow Vermont households to pay for qualifying weatherization projects as well as heat pumps, advanced wood heating systems, and health and safety measures through a monthly charge on their utility bill that can be paid back over time. Both homeowners and renters can participate in the program. Although the program is open to Vermonters of all incomes, the majority of program funding is targeted to households earning 80% to 120% of the area median income.

WRAP began through the collaborative vision of the Weatherization at Scale coalition of Vermont energy partners. The WRAP pilot, proposed by the Governor in 2021, was funded by $9 million in State appropriations in June of that year. After working with utility partners to develop the program, prepare tariffs, and create program agreements, WRAP was launched at the State House in December 2022.

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[30] Per the Vermont Climate Council's 2021 Climate Action Plan, Appendix 11, the adopted Damages-Based SCC at a 2% discount rate was adopted, which equates to a 15-year levelized value of $128/short ton CO_2 in 2021 dollars

[31] https://publicservice.vermont.gov/efficiency/building-energy-standards/building-energy-standards-update

WRAP's on-bill payment mechanism intends to address challenges commonly encountered in weatherization, including high upfront costs and limited access to credit. WRAP will not run credit checks on customers, instead verifying a clean utility bill payment history. If a customer moves, the next occupant of the property will pay the surcharge for the time they occupy the property and experience the benefits of the measures. WRAP projects are reviewed to ensure that calculated annual savings exceed the customer's WRAP repayment charge by at least 10%.

WRAP will be offered through its Program Administrators: Vermont Gas Systems, Efficiency Vermont, and Burlington Electric Department. They will connect customers with approved contractors, who will perform energy audits and recommend weatherization projects to customers. The Program Administrators will confirm that the measures meet energy savings targets and will determine the incentives that the customer is eligible for and whether an initial customer contribution is needed. Vermont Housing Finance Agency will provide capital and incentives for the remaining upfront costs of the project using state funding. After work is completed, the WRAP charge will be added as a separate line item on the customer's utility bill by their gas or electricity provider. At this time, Green Mountain Power, Ludlow Electric, Vermont Electric Cooperative, VGS, and Burlington Electric Department plan to offer the program to their customers.

4.1.4 Federal Funding

As discussed in Section 1.4, the State has received a large influx of funding through the American Rescue Plan Act (ARPA) that has been appropriated for energy related projects and is in the process of receiving additional funds through the Infrastructure Investment and Jobs Act (IIJA), also called Bipartisan Infrastructure Law (BIL). The Inflation Reduction Act, passed in August 2022, also contains additional funds for energy programs. Much of Section 1.4 is repeated here for convenience.

In 2021 and 2022 Vermont appropriated $150 million in ARPA funds to support efforts in the thermal sector:

- $80 million for weatherization programs, including $45 million to the Office of Economic Opportunity for low-income weatherization programs and installation of heat pumps and other devices, and $35 million to grant to Efficiency Vermont for weatherization incentives to Vermonters with moderate incomes. This funding, proposed by the Governor and passed by the Legislature in 2022, follows $7 million in ARPA funding allocated the year prior to Efficiency Vermont for moderate income weatherization and workforce development initiatives.
- $15 million to the Department of Public Service, $10 million of which was intended for "the Affordable Community-Scale Renewable Energy (ACRE) Program…to support the creation of renewable energy projects for Vermonters with low-income," and $5 million to be "allocated by the Clean Energy Development Board:"
    - The ACRE Program will deliver on-bill credits to eligible customers coming from the generation of renewable energy. Credits will come via participating distribution utilities, each offering a unique program with a range of credits of

$12-45 for 5-10 years. These programs will serve as pilots, offering insight into different models of what an "Affordable Community-Scale Renewable Energy Program" can be, perhaps leading to a statewide program in the future and/or an alternative to net-metering.

- The Clean Energy Development Fund developed several programs to allocate $5 million:
  - The School Heating Assistance with Renewables and Efficiency Program (SHARE) offers support to schools in need of financial assistance for heating repair, improvement, and upgrade projects. SHARE was initially funded with $2.5 million of the CEDF Board's $5 million allocation. An additional $1.25 million was transferred to the program following the discontinuance of the Whole-Home Clean Energy Assistance Program and the Interest Rate Buydown Program. There has been significant interest in this program with funding requests for eligible projects totaling more than $11 million.
  - The Hospitality HVAC Assistance Program offers assistance to hospitality, tourism and travel services businesses that were negatively affected by the pandemic. The program is funded with $250,000, offering grants of $10,000-25,000 for HVAC repair, improvement and upgrade projects that were delayed due to the pandemic.
  - Several other programs were developed but ultimately not moved forward: The Whole-Home Clean Energy Assistance Program was designed to deliver $1 million of ARPA funding to households with low-income for efficiency measures and heating system improvements, but was duplicative of other state programs. An interest rate buydown was not allowed under the ARPA rules.

- $20 million to provide financial and technical assistance for low- and moderate-income Vermonters to upgrade home electrical systems, enabling installation of energy saving technologies.
- $5 million for a "Switch and Save" program to provide financial and technical assistance for Vermonters with low and moderate income to install, at low- or no-cost, heat pump water heaters, with a focus on replacing water heaters near the end of their useful life.
- $7 million for load management and storage efforts to assist Vermonters with low- and moderate-income customers to purchase electric equipment for heating, cooling, and vehicle charging. In addition, investments will be made in load control and management platforms to enable smaller municipal and cooperative utilities to capture and share benefits of load management and funding for municipal back-up electricity storage installations.
- $45 million for the Municipal Energy Resiliency Grant program to extend services and support to under resourced municipalities across Vermont. The funding provides $5 million in investment grade building assessments, $1 million for the creation of four limited-service staff positions, $2.4 million for Regional Planning Commissions (RPCs) support or program operations, and $36.6 million in project funds capped at $500,000 per

municipality. Further funds are assigned via IIJA funds (see below) to establish a revolving loan fund for use by municipalities beyond the scope of ARPA monies.

Through the Inflation Reduction Act passed in August 2022, the Department of Public Service will receive direct funding via two programs: Home Energy Performance-Based Whole House Rebates (HOMES) and High-Efficiency Electric Home Rebate Program. The Department anticipates receiving approximately $29 million for each of the programs.

The HOMES program will provide rebates for whole-house energy saving retrofits. Additional incentives may be provided to households earning less than 80% of the area median income.

The High-Efficiency Electric Home Rebate Program will provide up to $14,000 per household including $8,000 for heat pumps, $1,750 for heat pump water heaters, and $840 for electric stoves. This program may also include rebates for improvements to electrical panels or wiring and home insulation or sealant. Eligible recipients must fall below 150% of the area median income.

4.2 Thermal Fuels Demand

The US Department of Energy's Energy Information Administration (EIA) provides data on most thermal energy consumption. (An exception is biomass, such as wood, used for heating purposes.) Because EIA data is often delayed by two years to ensure data quality, most data in this section reflects 2020.

4.2.1 Heating Degree Days and Impact on Demand

How much energy Vermont needs to meet its thermal needs depends on the weather. Heating fuel use increases noticeably during particularly cold winters, and electricity similarly increases for cooling during unusually hot summers. "Heating Degree Days" and "Cooling Degree Days" are metrics allow adjustments to fuel consumption to understand usage independent of weather.[32] Over the last twenty years, the amount of Cooling Degree Days in New England has increased by 30% and the amount of Heating Degree Days has decreased by 6.5%.

[32] Heating and Cooling Degree Days compare the mean (the average of the daily high and low) outdoor temperatures recorded for a location to a standard temperature, usually 65° Fahrenheit (F) in the United States. The more extreme the outside temperature, the higher the number of degree days. A high number of degree days generally results in higher levels of energy use for space heating or cooling.

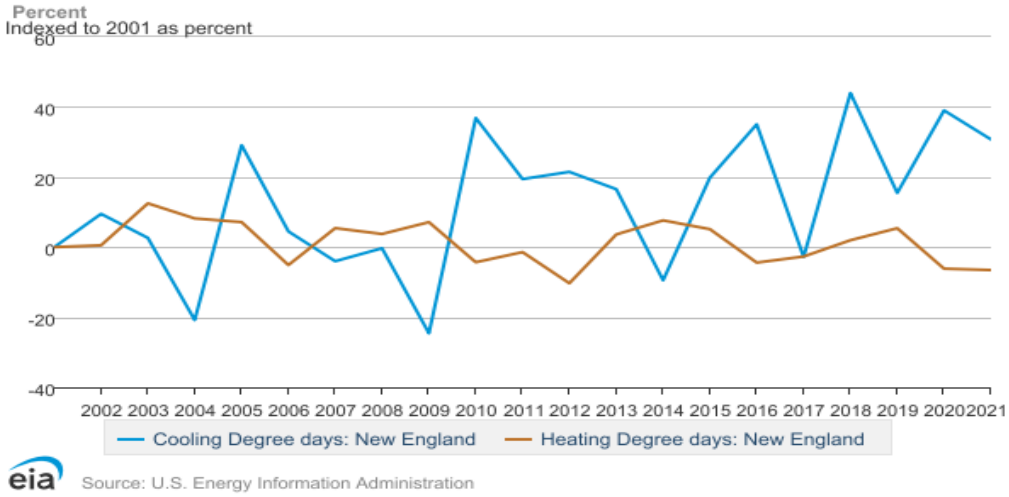

Figure 35: Heating and Cooling Degree Days Relative Change, 2002-2021[33]

The amount of oil, kerosene, and propane sold has slight variations based on the number of heating degree days and reactions to price effects.

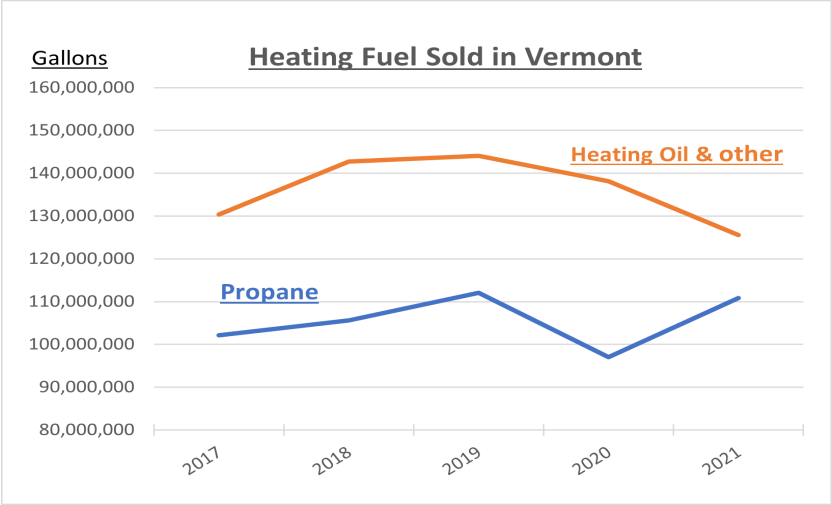

Figure 36: Heating Fuels Sold in Vermont, 2017-2021[34]

4.2.2 Thermal Energy Usage by Fuel Type

Fuel sources of thermal energy for 2020 are basically unchanged from 2019. Fossil fuels are still the dominant heating source in Vermont. Traditional wood stoves and advanced wood heating

[33] Energy Information Administration, https://www.eia.gov/outlooks/steo/data/browser/#/?v=28&f=A&s=&start=2001&end=2021&chartindexed=1&linechart=ZWCD_NEC~ZWHD_NEC&maptype=0&ctype=linechart&map=&id=

[34] Data from Department of Taxes on Fuels Delivered to a Business or Residence. Heating oil & other includes Kerosene, and other small amounts of dyed diesel that may not be used for heating fuel.

system have increased slightly. Electric heating via heat pumps has increased but is still a small fraction of the overall thermal energy. Figure 37 shows the sources of all thermal energy in Vermont in 2020.

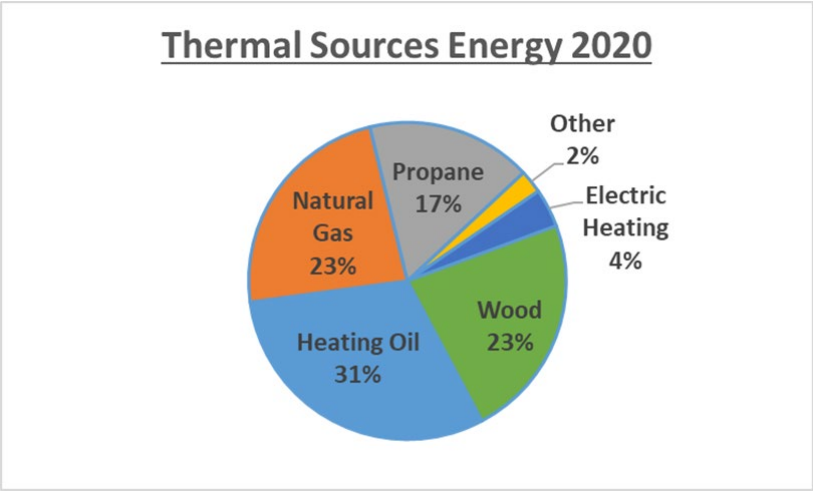

Figure 37: Vermont Thermal Energy Sources by Fuel[35]

Vermonters often use more than one fuel for their thermal needs. The *primary* source of residential fuel use in Vermont remains fuel oil, although it has had a slow and steady decline over the last decade. Wood as a primary fuel dropped surprisingly in 2019 and 2021 (no data was collected in 2020) and electricity as a primary fuel had a significant increase since 2019.

[35] Energy Information Administration for 2020. Vermont Data & PSD estimates for amount of electricity used for heating and adjustments made on wood based on historical Vermont data for wood used for heating, such as the 2019 Residential Heating Fuel Assessment published by the Vermont Department of Forests, Parks and Recreation.

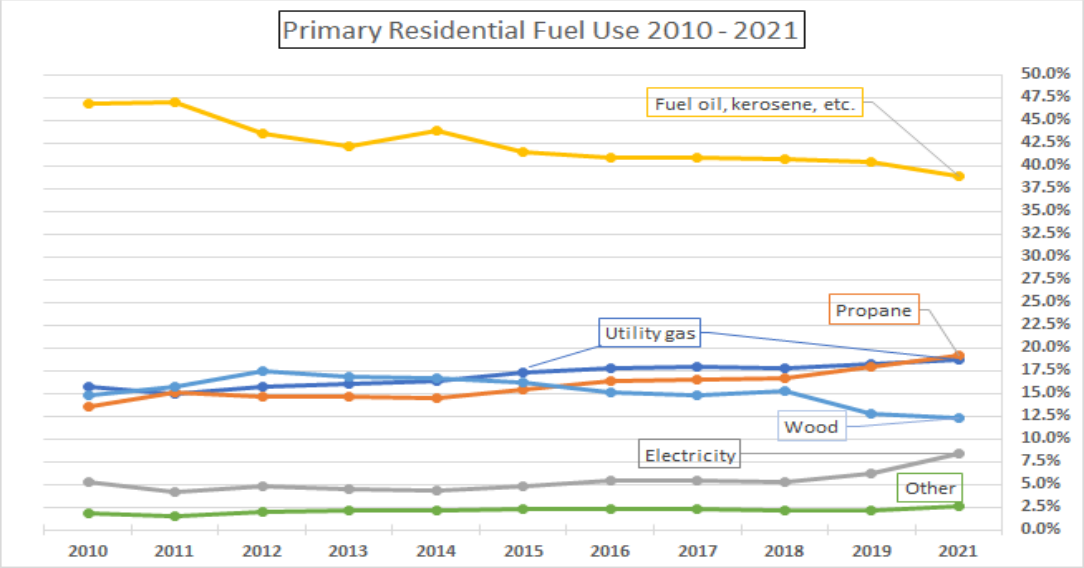

Figure 38: Primary Residential Fuel Use[36]

Despite the decline in wood heating reported by the EIA data, Vermont-specific data shows an increase in the number of Advanced Wood Heating systems installed in Vermont. The Clean Energy Development Fund incentive program has been promoting advanced pellet boilers and furnaces over the last seven years, providing incentives for 420 central pellet heating systems in Vermont buildings, mainly homes. With the recent increase in fossil fuel prices, the program saw a rapid increase in activity during the third quarter of 2022. It is estimated there are over seven hundred pellet fueled heating systems in Vermont, not including the thousands of pellet stoves in use.

[36] US Census Bureau, 2021 American Community Survey, House Heating Fuel. "Which fuel is used most to heat this house, apartment, or mobile home?" https://data.census.gov/table?q=Vermont/heating&t=Heating+and+Air+Conditioning+(HVAC)&tid=ACSDT1Y2021.B25040

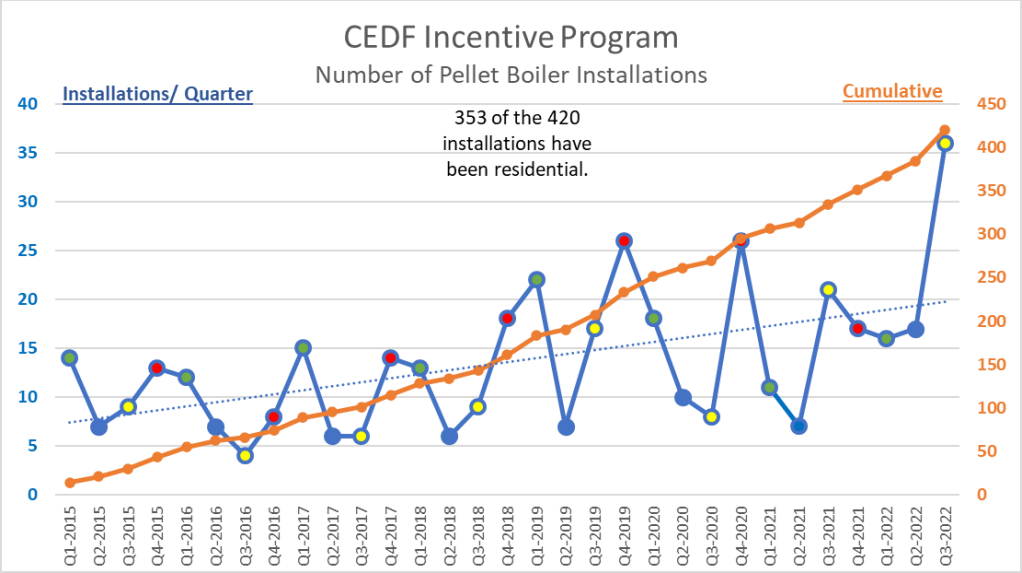

Figure 39: Pellet Boiler Installations in Vermont[37]

4.2.3 Thermal Energy by Sector

Residential heating accounts for the largest use of thermal energy in Vermont.

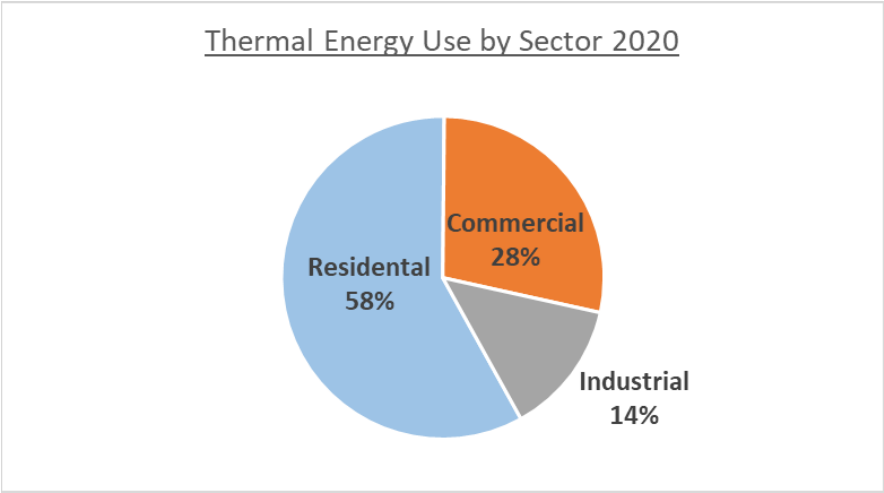

Figure 40: Thermal Energy Use by Sector, 2020[38]

[37] Data from Clean Energy Development Fund as of October 1, 2022

[38] Energy Information Administration, State Energy Data System for 2020.

4.2.4 Fuel Use by Housing Type

The American Community Survey (ACS) conducted by the US Census Bureau asks residents what fuel they use most to heat their house, apartment, or mobile home. Below are two charts showing the ACS five-year estimate based on survey results of Vermonters that own and rent their homes/apartments/mobile homes. Vermonters that rent rely more on electricity and utility-supplied natural gas then do those that own their homes.

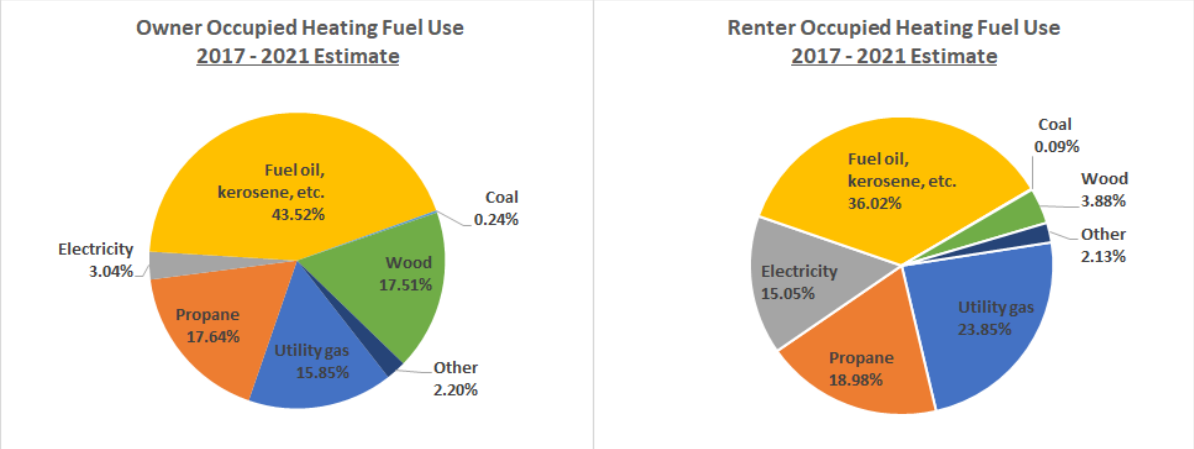

Figure 41: Heating Fuel Source by Housing Type [39]

4.3 Thermal Fuel Prices

All heating fuel prices rose during 2022, but unregulated fossil fuels have increased the most. (Natural gas is the only regulated fossil fuel delivered in Vermont.) Fuel oil prices rose 86% and kerosene rose 102% between October 2021 and October 2022.

[39] American Community Survey, 2021 Tenure by House Heating Fuel; Five-Year Estimates. https://data.census.gov/table?q=Vermont/heating&t=Heating+and+Air+Conditioning+(HVAC)&tid=ACSDT1Y2021.B25117

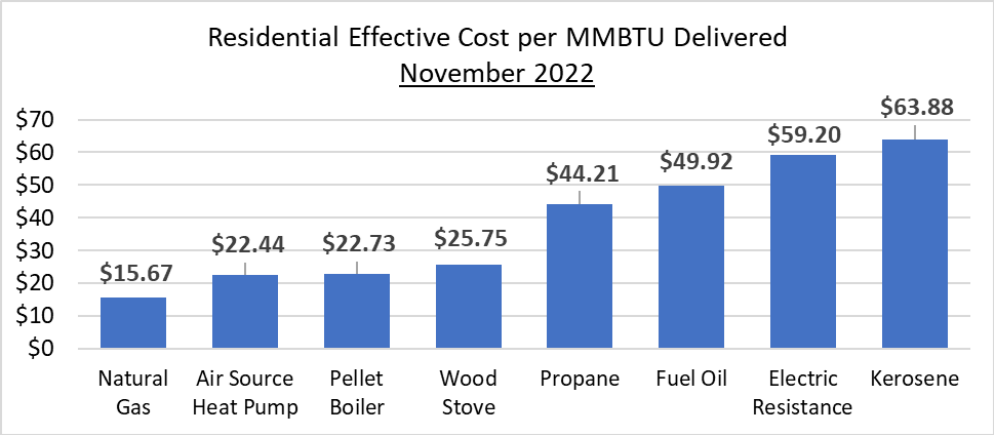

Figure 42: Cost of Residential Heating Fuels, November 2022 [40]

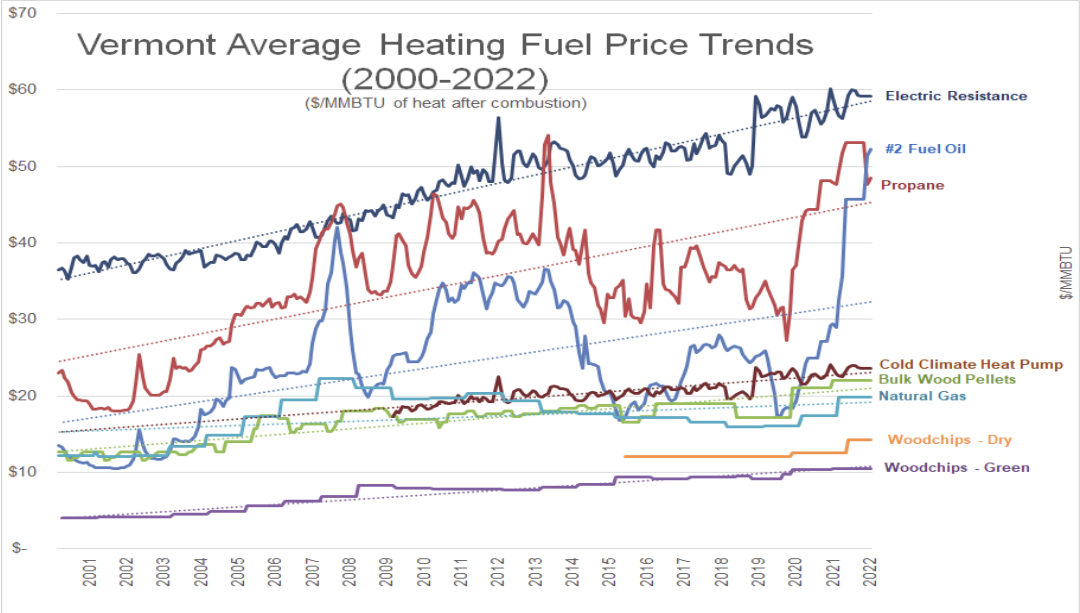

Figure 43: Average Heating Fuel Price Trends, 2000-2022 [41]

Figure 44 below shows what the average household in Vermont would spend on heating costs for each fuel, assuming that each fuel met 100% of the thermal demand of the average household (which the PSD estimates to be 83 MMBTU/year).

[40] Fuel price data collected by the Department of Public Service in November 2022

[41] Data collected by PSD and VEIC, last updated in November of 2022.

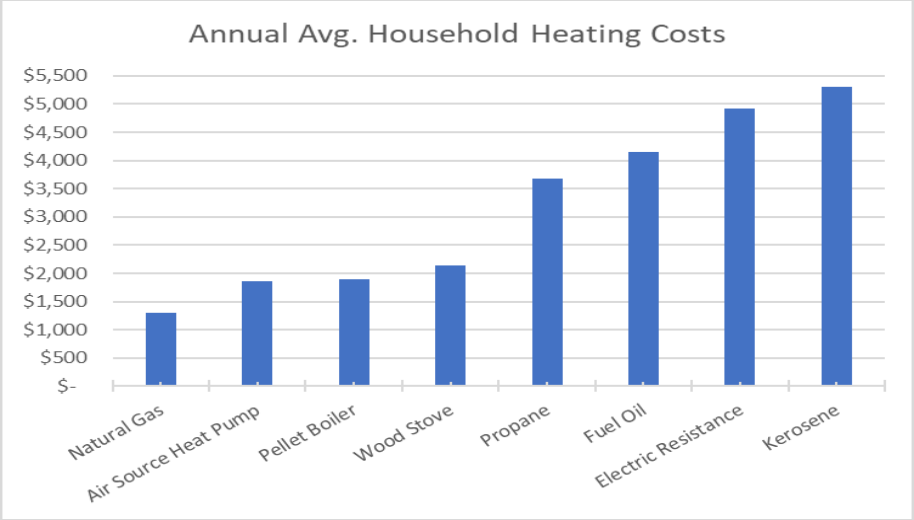

Figure 44: Annual Average Household Heating Costs by Fuel Type [42]

All fuels have taxes and fees associated with them—some more than others. The figure below shows the taxes or fees of select energy sources, compared to the relative CO_2 emissions per MMBtu of energy provided. A much greater percent of total cost of electricity is charged fees (including efficiency charges that support reduced energy use) than fossil fuels.

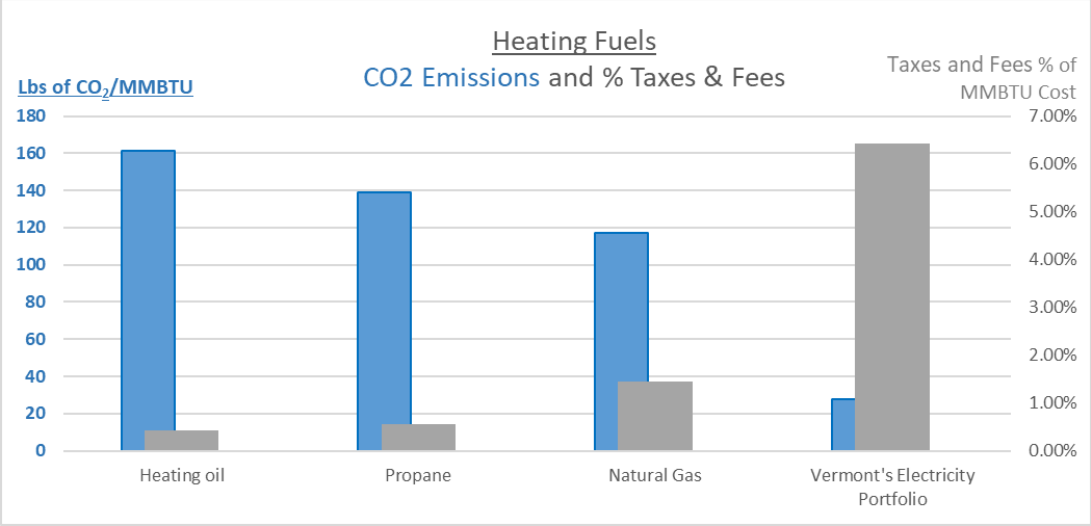

Figure 45: Taxes and CO_2 Emissions for Select Fuels [43]

[42] Annual average cost based on fuel price data collected by the PSD in November 2022

[43] Based on heating fuel market price collected by the PSD in November 2022

4.4 Weatherization

Vermont's housing stock is composed of a high proportion of older buildings that require more energy weatherized and newer buildings. Weatherization programs focus on improvements to building insulation and air sealing to reduce the energy required to heat and cool indoor spaces, homeowner costs, and the carbon emissions from burning of fossil fuels for space heat. Most weatherization programs also offer incentives to retrofit heating and ventilation equipment to further reduce energy costs and improve indoor air quality. Act 89 of 2013 (10 V.S.A. § 581) set residential building energy efficiency goals including the goal to weatherize 80,000 homes by 2020. The 2022 Comprehensive Energy Plan set a new target of comprehensively weatherizing a total of 120,000 homes by 2030.

There are five major weatherization programs in Vermont that are contributing to meeting the building energy goals of the state: Efficiency Vermont's Home Performance with ENERGY STAR program, Vermont Gas Systems' Home Retrofit program, the Burlington Electric Department, the Weatherization Assistance Program agencies coordinated by the Office of Economic Opportunity (OEO), and 3E Thermal. For this year's report, OEO project completions will be reported as the sum of the regional Weatherization Assistance Programs, which serve mostly single-family homes, and 3E Thermal, which performs deeper energy retrofits on multifamily buildings and is largely funded through OEO.

The five weatherization organizations' 2021 accomplishments are summarized below. The average fuel usage reduction is 22% for the 2,789 comprehensive energy retrofit projects completed in 2021.

Metric	Amount	Description
Total projects (# of units served)	**2,789**	Total number of housing units weatherized, including all comprehensive projects completed through the five participating organizations (EVT, VGS, BED, OEO, and 3E Thermal).
Average % fuel usage reduction	**22%**	Average fuel usage reduction for projects completed. Fuel use reductions measured using actual fuel usage data when available and estimates when fuel usage data is unavailable.
Carbon emissions reductions (pounds) **Carbon emissions reductions (tons)**	**5,343,556** **2,672**	Carbon reductions use a uniform calculation method based on Federal standards published on the EIA website for fossil fuels, and Department of Public Service values for electricity savings.
Incentive costs	**$16,775,379**	Direct financial incentives to the homeowner or building owner
Participant costs	**$7,990,071**	Participant contributions to the cost of building improvements
Total project costs	**$24,765,450**	Total costs

Figure 46: 2021 Weatherization Accomplishments

Vermont has weatherized approximately 33,000 units through 2021. Meeting the new target established in the 2022 CEP will be challenging given the current economic conditions and workforce availability, although substantial funding increases through ARPA and IRA (see Section 1.4) will presumably draw more contractors and workers to the weatherization industry. The figure below shows the cumulative completed weatherization retrofits through 2021.

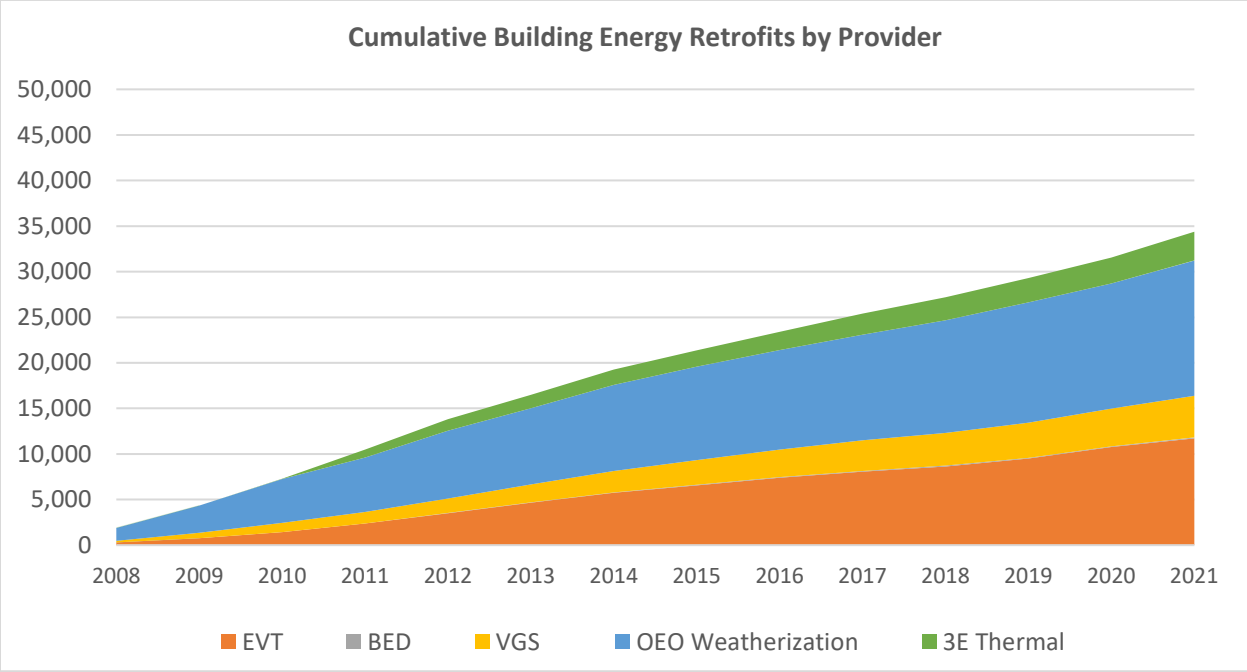

Figure 47: Historical and Forecasted Building Energy Retrofits

State Agency Energy Plan Update

In fiscal year (FY) 2021, the Department of Buildings and General Services (BGS) successfully audited over 376,261 square feet of building space, equal to 13% of BGS's total space. The increase in audited square feet, from 246,303 square feet in FY2020, was a result of concerted efforts on the part of BGS Operations and Maintenance staff to work with the Energy Office and their audit vendors to adjust energy audit procedures to accommodate COVID-19 site safety protocols. While the square feet audited in FY2021 increased, the program saw a decrease in project savings because of the difficulty imposed by COVID-19 in initiating and completing construction projects across state facilities. Figure 48 provides the results from the results from SEMP Activities for FY2021.

Site	Project Focus	Cost	KWH*	MMBTU	First-year $ Savings	Lifetime $ Savings	Pay back Period
Numerous locations	Efficiency VT Prescriptive Projects				$6,031.60	$90,215	
Numerous locations	Solar Net Metering				$75,809		
Barre Courthouse Lighting	LED Lighting and Controls	$341,169	58,561		$17,894.83	$268,420	4.3
Middlebury Mahady Courthouse	LED lighting, Building Heating, Ventilation, Air Conditioning (HVAC)	$81,323	63,794	13,519	$36,071	$541,076	2.3
Burlington 108 Cherry St	Exterior LED Lighting	$2,773	29,415		$286.30	$4,294	9.6
Montpelier 120 State Street Can Lights	LED Lighting	$1,080	5,610		$634.95	$9,524	1.7
Montpelier 120 State St Rm 103 & 105	LED Lighting	$780	19,650		$174.16	$2,612	4.5
Royalton Police Barracks	LED Lighting	$6,516	12,337		$2,089.23	$31,337	3
Newport Hebard State Office	LED Lighting	$49,151	94,766		$17,417.37	$348,347	2.8
Pittsford Fire & Training Academy	Boiler Burner Replacement	$13,714		1,991	$1,958.39	$29,374.73	7
Totals		**$496,509**	**284,133**	**15,510**	**$158,366**	**$1,325,203**	

Figure 48: 2021 Buildings and General Services Projects

Site	Project Focus	Cost	KWH	MMBTU	First-year $ Savings	Lifetime $ Savings	Payback Period
Numerous Locations	Efficiency Vermont Prescriptive Projects				$37,295	$459,035	
Numerous Locations	Solar Net Metering***				$76,251		
Brattleboro State Office Building	Window Replacement	$7,035		37	$709	$21,269	9.9
Montpelier 120 State Street CVO Area	LED Lighting	$720	1,584	5.4	$210	$1,053	3.41
Flexible Load Management (FLM) Pilot, Waterbury Office Complex, Bennington Court, Brattleboro State Office Building	Building controls updates	$56,842		1.4	$12,819	51,276	1.6
Rutland Garage	LED Lighting	$690	7,450		$1,118	$16,763	.6
Totals		**$65,288**	**9,034**	**43.8**	**$128,402**	**$549,396**	

Figure 49: 2022 Buildings and General Services Projects

As provided in their annual report for FY2022, BGS successfully audited over 118,151 square feet of building space, equal to 4% of state-owned space under the jurisdiction of BGS. The decrease in audited square feet, from 376,261 square feet in FY21, was a result of staffing shortages within the Program following the departure of the State Energy Management Program (SEMP) Manager. In FY2022, project implementation continued to be impacted by the difficulties imposed by COVID-19 in initiating and completing construction projects across state facilities as well as restrictions in available funds and increases in contractor costs. In FY2022, the BGS team began work on the SEMP Expansion pilot utilizing the $600,000 two-year matching grant supplemental resources from Vermont Low Income Trust for Electricity (VLITE) and the Clean Energy Development Fund. Program staff successfully recruited and hired the first technical support position to coordinate data collection and assessments for municipalities. Figure 49 provides the results from the results from SEMP Activities for FY2022.

In June 2022, Governor Scott signed Act 172, creating the Municipal Energy Resiliency Grant program as an extension of the SEMP to extend services and support to under resourced municipalities across Vermont. The legislation assigned $45 million in American Rescue Plan Act State Fiscal Recovery (SFR) funds to the Program to provide $5 million in investment grade building assessments, $1 million for the creation of four limited-service staff positions, $2.4 million for Regional Planning Commissions (RPCs) support or program operations, and $36.6 million in project funds capped at $500,000 per municipality. The legislation further assigns $2.8 million in Infrastructure Investment and Jobs Act funds to establish a revolving loan fund for use

by municipalities beyond the scope of ARPA SFR monies. SEMP staff will be working with program partners Efficiency Vermont, the Vermont League of Cities and Towns, and the RPCs to design and stand up the program. Staff anticipate a program launch in the fall of 2023.

Appendix A: Progress Toward 2022 Comprehensive Energy Plan Recommendations

This appendix is intended to provide a quick reference to all 2022 Comprehensive Energy Plan recommendations and progress toward their achievement. Recommendations may be edited slightly for brevity and clarity from the versions in the Energy Plan. This table is expected to be updated regularly.

Chapter 3: Equity	
Recommendation	**Progress**
The Department of Public Service should develop a diversity, equity, and inclusion strategy to advance the transition to a just and equitable energy system for Vermonters and to guide actions moving forward, including staff training.	The Department has proposed a State Energy Program-funded budget to support staff training on issues of energy equity and facilitate the development of a DEI strategy. The Department expects to develop a workplan and begin implementing this step in 2023.
Equity should be considered as core criteria in all decision-making, alongside least-cost and environmentally sound principles as defined within the statutes that guide energy policy in Vermont, including 30 VSA 202(a), 209, 218(c), 225, 248, 8005, and 8010, among others.	Act 154, in establishing an environmental justice policy for Vermont, requires that "covered agencies" defined in the statute (including the Department) shall consider cumulative environmental burdens and access to environmental benefits "when making decisions about the environment, energy, climate, and public health projects; facilities and infrastructure and associated funding."[44] The statute requires the Agency of Natural Resources to adopt rules on or before July 1, 2025 on how the covered agencies should implement consideration of cumulative environmental burden. The Department of Public Service added equity-related provisions to the draft revised Integrated Resource Plan (IRP) Guidance which guides these plans that articulate the decision-making frameworks utilities utilize.
All strategies to promote the energy system transition should be designed to collect the robust and reliable data required to better understand baseline and historical inequities, and to measure progress towards remediation.	The Climate Action Office, in coordination with the Climate Council, is developing a Measurement and Tracking tool toward this end. In addition, the Department of Public Service proposed to allocate $150,000 in State Energy Program funding to support the next phase of its data project, which aims to modernize the Department's data infrastructure and transparently share data and report on progress towards meeting clean and renewable energy goals (see Section 2.1.7 for more details). This project will also look to develop and include data and metrics related to advancing energy equity.
The Department of Public Service should complete a review of existing practices and procedures for energy-related public processes and recommend changes, as warranted, to encourage more inclusive and transparent engagement with Vermonters.	In 2022, the Department proposed to allocate State Energy Program funding to support the development of a community engagement plan as required by Act 154. The Department expects this effort to include a review of existing practices and procedures of engaging with the public on issues related to energy and that this work will commence in 2023. See also Section 2.1.1 of this Annual Energy Report.

[44] https://legislature.vermont.gov/Documents/2022/Docs/ACTS/ACT154/ACT154%20As%20Enacted.pdf

The Department of Public Service should continue working with sister agencies to establish and implement frameworks for consistently addressing issues of equity and justice across Vermont energy policy.	The Department's Data and Equity Policy Manager continues to engage with and support the Just Transitions Subcommittee of the Vermont Climate Council, which involves close coordination with the Climate Action Office and other state agencies with staff participating in that work. The Department will participate in the Interagency Environmental Justice Committee established by Act 154.
Act 174 enhanced energy plans completed by regional planning commissions and towns should include analyses of the potential equity impacts of proposed policies, objectives, and goals in the plans.	With the 2022 CEP, the Department of Public Service published a revised set of standards that regional planning commissions and municipalities must meet in order to receive an affirmative determination under Act 174. The revisions require RPCs and municipalities consider potential equity-related impacts of policies and objectives aiming to achieve energy-related goals. Several RPCs and municipalities are in the process of updating their enhanced energy plans to meet these standards.

Chapter 4: Grid Evolution	
Recommendation	**Progress**
Load Flexibility	
Utilities who have not yet done so should develop smart rates and begin exploring direct DER control	• Act 55 of 2021 requires utilities to implement EV rates by June 30, 2024 • Act 13 of 2021 enables municipal and cooperative utilities to pilot smart rates
Load flexibility initiatives should be codified in policies, regulations, and programs so they can be relied on as inputs to grid planning efforts	• See Acts 55 and 13, above • Several utilities, including GMP, WEC, and VPPSA members, have pilots or programs in place to provide EV chargers to customers in exchange for the ability to manage time of charging • Several utilities, including GMP and VEC, are piloting Flexible Load Management (FLM) initiatives that have the potential to become tariffed offerings • VELCO has studied and will continue to evaluate the penetration of load management needed to avoid or mitigate transmission buildout
Grid & Communications Infrastructure	
The state, utilities, Communications Union Districts (CUDs), and others should continue the multi-pronged push to expand broadband statewide	• Unprecedented investments using ARPA and IIJA funds are currently being made to expand broadband statewide[45] • CUDs and utilities are cooperating to efficiently use shared infrastructure[46]
Municipalities, regions, emergency management professionals, communication providers, DER developers, transportation planners, and utilities should have forums to plan collaboratively toward an optimized grid	• The Vermont System Planning Committee (VSPC) – which includes utilities as well as environmental, planning, residential, and commercial representatives – meets regularly to discuss transmission planning issues

[45] https://publicservice.vermont.gov/vt-community-broadband-board-vcbb/broadband-resources-towns/broadband-funding; https://publicservice.vermont.gov/press-release/vt-community-broadband-board-announces-116-million-broadband-construction-grant

[46] https://greenmountainpower.com/news/vermont-electric-co-op-and-green-mountain-power-announce-new-broadband-deployment-program/; https://vcgi.vermont.gov/document/vermont-utility-pole-gis-data-standard

	• The PSD is developing a tool for regional planners to assess "headroom" for additional generation on distribution and transmission systems, to be released early 2023.
Utilities should develop or expand hosting capacity maps for solar and other DERs that will inform locational pricing, DER programs, and land use planning	• GMP has a circuit/substation capacity map it updates regularly, and has created additional grid siting tools for use by developers [47] • BED has a distributed generation map indicating hosting capacity that it updates regularly[48] • VEC has a web-based generation constraint map it updates monthly[49] and intends to develop a physics-based modeling tool to help generators understand potential needed infrastructure upgrades and costs • VELCO has a static transmission capacity map based on the Long-Range Transmission Plan[50], and has begun coordination with utilities to overlay hosting capacity data as information policies allow
Public Utility Commission Rule 5.500 should be updated to incorporate: storage, collective impacts and cluster studies; distributed aggregations; smart inverters; interoperability; and DER cybersecurity	The Public Utility Commission (PUC) has made significant draft revisions to Rule 5.500 that encompass many of these items, and will likely formalize these updates in 2023[51]
Stakeholders should work toward adoption of open communication standards to advance equitable and scalable flexible load management capabilities	The PSD has initiated a Technical Working Group affiliated with the VSPC to tackle complex topics such as interoperability, communication standards, full implementation of IEEE 1547, UL 1741 Supplement B, etc.
DER Market Integration & Customer Programs	
DER programs should incorporate time- and locational pricing, informed by and aligned with system costs and benefits	• The PSD has recommended in the Rule 5.100 rulemaking that excess generation from net-metering systems be paid an avoided-cost-based rate • The PUC in its draft of updates to Rule 5.100 enables utilities to develop tariffs to address generation interconnecting in constrained areas of the grid with fees to potentially be assessed based on likely future grid upgrade costs or economic damages • See also PSD electricity engagement process, Section 2.1.1
Utilities should make real-time usage and rate data available to and actionable by customers	Utilities without Advanced Metering Infrastructure (AMI) now have plans and funding to deploy it (including $8million appropriated in FY23 budget), in part for the ability to implement rate-driven load management responses. Several utilities make hourly demand data available to customers.
Forums that allow utilities to effectively coordinate and facilitate a shared approach to DER standards should be developed	The VSPC and Technical Working Groups as described above provide one such forum. The VELCO Operating Committee is another.

[47] https://gmp.maps.arcgis.com/apps/webappviewer/index.html?id=4eaec2b58c4c4820b24c408a95ee8956

[48] https://burlingtonvt.maps.arcgis.com/apps/Embed/index.html?webmap=bb1b9156d8294e308ecfe803131e8c00&extent=-73.2731,44.4574,-73.1094,44.5091&zoom=true&scale=true&legend=true&disable_scroll=false

[49] https://www.arcgis.com/apps/mapviewer/index.html?webmap=3d526efbc62b4ab78aa5d2b56b3b8fef

[50] https://www.velco.com/assets/documents/2021%20VLRTP%20to%20PUC_FINAL.pdf, page 43

[51] https://puc.vermont.gov/about-us/statutes-and-rules/proposed-changes-rule-5500

Chapter 5: Transportation and Land Use	
Recommendation	**Progress**
Pathway: Vehicle Electrification ***Strategy: Expand Electric Vehicle Market Share Through Incentives***	
The Agency of Transportation should lead research to examine the optimal vehicle incentives that should be offered for each income category	VTrans-funded analysis planned for 2023 by Center for Sustainable Energy.
Continue and enhance new and used EV purchase incentives, with a focus on ensuring equitable distribution of the burdens and benefits support.	Ongoing through Tier III and State incentives
Fund MileageSmart at levels that meet customer demand. Incentives for AEVs and PHEVs should reflect their contribution toward customer affordability and greenhouse gas reductions, and should aim to help assure equitable participation in EV deployment.	The Legislature appropriated $3 million for MileageSmart in 2022
Vermont should establish an incentive program for electric medium- and heavy-duty (MHD) vehicles to help move that market, and should consider making this program available to both individuals and commercial enterprises, including farms.	Ongoing via limited available DERA and VW settlement grant funding. Funding available via Inflation Reduction Act grant programs and tax credits will facilitate creation and implementation of an incentive program for MHD electric vehicles.
Based on a VTrans study of technical feasibility and costs and the outcome of ANR's Electric School and Transit Bus Pilot Program, determine the viability and cost-effectiveness of converting Vermont's diesel transit bus fleet to electric, and implement recommendations of that study.	Transition plan completed and available at https://vtrans.vermont.gov/sites/aot/files/publictransit/documents/VTrans%20Zero-Emission%20Transition%20Plan_Final01312022.pdf. Implementation ongoing among transit agencies, especially (although not exclusively) Green Mountain Transit.
Pathway: Vehicle Electrification ***Strategy: Facilitate Increased EV Market Share through Supporting Infrastructure and Policy***	
Advance the implementation of the EVSE Deployment Plan currently under development by VEIC for VTrans, including public fast charging, workplace charging, and — especially — charging for residents of multi-unit dwellings (such as apartments and condos).	Ongoing through state funds and federal National Electric Vehicle Infrastructure (NEVI) Formula Program under Infrastructure Investment and Jobs Act
Advance the goal as articulated in Act 55 of 2021 to have, as much as practicable, a DCFC EVSE charging port available to the public within five miles of every Interstate interchange and every 50 miles along state highways.	Ongoing through IIJA NEVI funds, prioritizing interstates, US Route 2 and Route 7, and Vermont Route 9
This CEP sets a target for 100% of sales of all light-duty vehicles to be Zero Emission Vehicles by 2035.	Rules adopted in December 2022 by Agency of Natural Resources. See Section 3.1.1
Vermont should undertake the rulemaking process pursuant to ANR's existing authority and adopt amendments to adopt amendments to California's Advanced Clean Cars II and Advanced Clean Trucks regulations.	Completed; rules adopted in December 2022 by Agency of Natural Resources. See Section 3.1.1
Provide staffing and testing equipment to the Agency of Agriculture, Food, & Markets to develop, implement, and enforce the EV charging program by implementing NIST Handbook 44 and NIST Handbook 130 requirements, and by training staff on	Funding requested by Agency of Agriculture.

the use of meters in preparation for NIST to finalize protocols.	
Determine how to manage legacy EV charging infrastructure that does not meet NIST Handbook 44 and NIST Handbook 130 requirements, including a timeline for compliance or replacement of EVSE equipment.	Agency of Agriculture is focused on education and early replacement to achieve compliance.
Encourage distribution utilities to include utility load management for all new home and workplace EV charging. This is best accomplished by establishing load management as the default for new EVs.	In progress, with focus on 2024 EV rate offering requirement. See also PUC report on EV rate development. See https://puc.vermont.gov/news/report-vermont-legislature-act-55-2022-report-electric-rates-electric-vehicles for the 2022 report.
Pathway: Vehicle Electrification ***Strategy: Managing Electric Grid Impacts of EVs***	
Encourage regional and municipal planning to identify preferred locations for public-serving DC fast chargers, such as downtowns and village centers.	2022 updates to the Act 174 enhanced energy planning standards and guidance for meeting those standards now encourage regions and municipalities to plan for preferred siting locations of charging infrastructure as a way to support the shift towards electric transportation options (see Standard 7b).
Encourage distribution utilities to offer appropriate alternatives to standalone demand charges for public-serving fast chargers. Vermont utilities should consider offering rates that relieve fast charging load from traditional demand charges, provided that the rate covers marginal costs and reasonably protects the system from the burdens of new coincident system peak loads.	One utility currently offers an alternative to standalone demand charges for public-serving EV chargers. In addition, the Department of Public Service is providing support to VPPSA to develop rates for public charging on behalf of its 11 member utilities. It is not yet clear whether VPPSA will recommend alternatives to standalone demand charges.
Pathway: Cleaner Vehicles and Fuels ***Strategy: Increase Targeted Use of Low-Carbon Fuels***	
Continue to work with other jurisdictions on implementing the TCI-P cap-and-invest program for transportation fuels. Once a viable regional market exists, consider participating in TCI-P, with viability based on a clear evaluation of the societal, Vermont-specific, and customer benefits and costs of TCI-P and the uses of potential revenue from the program.	Ongoing. Regional market viability for the TCI-P program does not currently exist
Pathway: Support Land Use Patterns that Increase Transportation System Efficiency ***Strategy: Integration of Land Use Planning into Transportation Decision-Making Frameworks***	
With consultant support, ACCD should develop and execute a shared research agenda to build collective knowledge and understanding about the impact that land use decisions can have on achieving state goals.	Ongoing; completion expected in spring 2023. Funded through AOT, consultants are investigating how compact, mixed-use land use patterns affect vehicle miles travelled (VMT), mode share, and GHG emissions
ACCD should simplify the programs that designate Vermont's settlement areas, and support local policies and programs that provide a mix of equitable housing choices for both renters and homeowners.	Ongoing, with consultant support. Preliminary report expected July 2023
ACCD, in partnership with other state agencies, should estimate the range of benefits, including energy and climate benefits, associated with land use planning and transportation demand management investments.	Primary activity related to this is the research being pursued through the AOT research program (see above)

The Agency of Transportation, in collaboration with ACCD, should commission a thorough study of all of the costs and benefits associated with Transportation Demand Management, including but not limited to climate and energy impact.	Addressed, in part, through ongoing AOT Carbon Reduction Strategy on capital investments
Transportation and Land Use Pathway: Increasing Transportation Choices ***Strategy: Provide Safe, Reliable, and Equitable Public and Active Transportation Options***	
AOT should evaluate the impact, including benefits and challenges, of the Complete Streets program to ensure that it is working as intended.	No update
Carry out the policies recommended in the Vermont Rail Plan for both freight and passenger rail.	Ongoing
Encourage ridership on Amtrak service through continued marketing.	Ongoing, with $50,000 allocated by Legislature in 2022
Continue to improve rail infrastructure to reduce rail travel times.	Ongoing, with over $35 million allocated by Legislature in 2022 for service and improvements

Chapter 6: Thermal and Process Energy Use	
Recommendation	**Progress**
Pathway: Reduce Thermal Energy Demand ***Strategy: Weatherization at Scale***	
Support Increased funding with a mix of state and federal funds, consider a Weatherization carve out in any "Clean Heat Standard" (see below), and explore other sustainable funding solutions.	• See Section 4.1.4 regarding Federal Funding recently devoted to Weatherization • See below regarding consideration of a Clean Heat Standard • See Section 4.1.3 regarding on-bill financing mechanisms
The Department of Public Service, the Department of Financial Regulation, and insurance industry stakeholders should explore opportunities for collaboration on programs, such as weatherization, that reduce energy use and reduce risk.	Not started
Pathway: Reduce Thermal Energy Demand ***Strategy: Encourage Efficient Buildings and Equipment***	
The Department of Public Service's energy code updates should put Vermont on a path for all newly constructed buildings are net-zero ready by 2030.	A pathway to net zero ready over the next three code update cycles was established during the building code updates that will take effect in 2023. See Section 4.1.1.
The Department should consider both societal and customer cost effectiveness in analysis of code updates, starting immediately.	Both societal and customer cost-effectiveness estimates were included in the Rulemaking filings for both RBES and CBES.
The Legislature should pass a builder registry requirement, with a goal that 100% of builders are registered with VT OPR and aware of the building energy standards and training opportunities by 2025.	Act 182 of 2022 established Vermont Builder Registry and is being implemented by the Office of Professional Regulation.
The Legislature should authorize the Department to adopt the CBES stretch code by 2023 and authorize municipalities to adopt it.	No action was taken by the Legislature in 2022
The Department of Public Service should consider requiring residential new construction to install a minimum of 200-amp service to a home.	200-Amp service requirement was contemplated for the Residential Building Energy Standards update but was not adopted due in part to concerns over cost.
Municipalities should consider requiring permitting and certificate of occupancy for building construction. They should also provide information on the RBES	Municipalities may be considering these code related recommendations.

and CBES when these types of permits are being applied for per statue requirement.	
Municipalities should consider hiring a code official to review construction documents, receive RBES and CBES certificates, and enforce the building energy standards.	
Municipalities should consider adopting beyond base code standards	
Collaborate with other states with similar appliance standards to create a publicly accessible online database of qualifying equipment.	Ongoing
Pathway: Enhance Low-Carbon Technology and Fuel Choices ***Strategy: Consider a Clean Heat Standard***	
Consider the adoption of a Clean Heat Standard, including a Public Utility Commission Study of potential cost and equity implications under different design parameters and expected measures, including expected resource necessary to administer such a program. Then, the legislature should consider whether to authorize the Commission to adopt a Clean Heat Standard.	The 2022 General Assembly considered the adoption of a Clean Heat Standard, without the recommended Commission study of potential cost/benefit and equity implications under different design parameters. The Agency of Natural Resources, in coordination with the Department of Public Service, is studying the costs of a Clean Heat Standard as well as other policy design options to understand their relative impact.
The Department of Public Service should continue to evaluate equity and cost-effectiveness while verifying measure savings of Tier III programs in its RES reports.	Ongoing
Consider whether Tier III should become a part of any Clean Heat Standard.	Ongoing
Pathway: Enhance Low-Carbon Technology and Fuel Choices ***Strategy: Encourage Cleaner Technologies and Fuels***	
Continue to encourage the installation of heat pumps, particularly in weatherized or already high-performing buildings	Ongoing. Federal funding for Office of Economic Opportunity includes heat pump deployment and facilitation of deployment through support for upgrades of electric panels. Efficiency Vermont and electric distribution utilities continue to offer heat pump incentives.
Encourage innovative rate designs that encourage heat pumps and manage their operation consistent with requirements of the grid	Ongoing. See Grid Evolution section of Appendix A, as well as Section 1.2
Enable Efficiency Vermont to continue to pursue refrigeration management alternatives for the heat pump market in Vermont, to lower GWP refrigerants.	Enabled in Efficiency Vermont's Demand Resource Plan. Further support is being considered by Agency of Natural Resources.
When replacing end-of-life fossil fuel systems or building new buildings, full cost-benefit analysis of replacement sources, including advanced wood heat should be considered. Separately from the benefit-cost analysis, the state should also consider the health of the forest products industry in its decision making.	Under consideration
The state should support the conversion of as many of our schools as feasible to Advanced Wood Heat systems. To help address upfront costs of AWH systems, continue the sales tax exemption for advanced wood heat equipment that expires in June of 2023.	ARPA funding was provided by the legislature to the PSD and over $3 million was allocated for renewable and energy efficiency HVAC upgrades at schools with high levels of poverty.

The Clean Energy Development Fund should encourage local manufacturing and processing of advanced wood heat fuels and other products in the wood heat supply chain, including all forms of wood fuel including cord firewood, pellets, green chips, and dry precision chips; and it should support development of wood delivery infrastructure	The CEDF has been encouraging the supply side of advanced wood heating fuels but has not have the funds to provide incentives for this part of the advanced wood heating market. It has continued to provide incentives for installations of advanced wood systems that should build demand and that, in turn, should encourage more local supply to be built.
To develop the advanced wood heating workforce, training and education should be provided on AWH systems for HVAC professionals.	Ongoing
The Clean Energy Development Fund should continue to operate, and municipalities should avail themselves of, advanced wood heating programs to promote efficiency, decrease emissions and avoid impacts on vulnerable populations or places. An education campaign on best practices in selecting cordwood and wood pellet fuel, stove, and boiler/furnaces; storing wood fuel; and operating and maintaining wood-burning appliances should also be considered.	The CEDF has continued to provide incentives for advanced wood heating systems to residential and commercial customers. Few municipalities have made taken advantage of these incentives recently. Education campaign has not begun.
The Clean Energy Development Fund should continue to support wood stove change-out programs	The CEDF has continued this work for income qualified households with the addition of ARPA funds.
Municipalities should consider inclusion of the change-out of old wood heating systems for advanced wood heating as part of their Act 174 energy plans.	Municipalities should be considering this recommendation when updated their town and regional energy plans.
Vermont should continue to support the development of cost-effective district heating systems that are supplied by sustainably harvested biomass, to equitably distribute the benefits of district heating as well as the costs.	Ongoing
Compare a biomass-based diesel blending requirement to a clean energy heat standard or other sector-wide requirement, to determine whether one of these would be practical and effective. Such comparison should include a regional fuel market impact analysis.	Ongoing
Advocate for reporting requirements for percentages of BBD in heating fuels, to allow measurement of progress toward any implemented requirements and state renewable energy goals.	Ongoing
In partnership with fuel dealers and others, transition heating fuel supplies to an appropriate level of renewable fuels, particularly for customers that will have difficulty transitioning to electric sources or lack access to capital to make an energy transition.	State has taken no action.
Support fossil fuel dealers in a diversification and eventual transition of their businesses into energy service providers that sell a range of energy efficiency services and products.	See workforce development initiatives, for example Section 4.1.4

Chapter 7: Electric Resources	
Recommendation	**Progress**
Pathway: Further Decarbonization of the Electric Sector ***Strategy: Consider Design Options for a Carbon-Free or 100% Renewable Energy Standard***	
Consider adjustments to the Renewable Energy Standard and complementary renewable energy programs comprehensively, through a transparent an open process	See Section 2.1.1 regarding Department's Renewable and Clean Energy Policy Review
State Agencies should work collaboratively to ensure environmental justice and equity are incorporated consistently across siting policy in Vermont	Ongoing. See Section 1.1
Siting of energy infrastructure should avoid or minimize conversion of natural lands, and should seek to maintain the ecological functions of the land.	Ongoing
Re-evaluate Energy Efficiency Charge low-income definition and seek to expand to BIPOC individuals and communities, as appropriate.	Ongoing in current Demand Resources Plan proceeding before the Public Utility Commission.
Evaluate and build on successes of current Energy Efficiency Utility pilots for Flexible Load Management and refrigeration management.	Ongoing in current Demand Resources Plan proceeding before the Public Utility Commission.
The State should work collaboratively to modify the net-metered preferred site incentive structure.	Ongoing. See Section 2.1.1

Chapter 8: Finance	
Recommendation	**Progress**
Vermont's state finance institutions "FIs" (VEDA, VHFA and VBB) should investigate the optimal structure(s) needed to deploy low-cost capital at the scale and pace needed to meet energy and greenhouse gas emission reduction goals.	Three state FIs are working together to form a clean energy finance collaborative. There is a new opportunity for states to pursue clean energy financing via the Greenhouse Gas Reduction Fund under the Inflation Reduction Act of 2022. This new fund will be administered by the US Environmental Protection Agency, guidance for which should be available in late 2022 or early 2023. PSD and the Climate Office are engaged in conversations with the FIs to explore options for linking the state energy office's expertise with energy policy and technology with the FIs finance expertise.
Clean energy and climate-related finance tools and tactics used in Vermont should be reviewed to find economies of scale, cost savings, and opportunities to expand participation by marginalized and under-served communities. The state should continue using existing finance products and developing new tools, such as tariffed on-bill repayment, as vehicles to address key market problems or barriers.	Underway in connection with the opportunity presented by the Inflation Reduction Act's Greenhouse Gas Reduction Fund. See also Section 4.1.3 regarding the Weatherization Repayment Assistance Program.
Within the existing financial partners, the state should build the capacity to access energy financing opportunities at the federal level, with a dedication to finding and knowing how to obtain and deploy federal funds	PSD staff are working with the State and FI partners listed above to explore how to access federal resources under the IIJA and IRA.

Appendix B

REPORT ON VERMONT RENEWABLE ENERGY PROGRAMS

A Report to the Vermont General Assembly Pursuant to 30 V.S.A. § 8005b(b) and § 8005b(c)

Prepared by the Department of Public Service

January 15, 2023

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Introduction

In 2017, Vermont began implementation of the Renewable Energy Standard ("RES"), the first requirement in the state for electric utilities to provide renewable energy to their customers. Prior to this, programs were in place to support development of renewable resources, but the renewable attributes could be sold out of state, and therefore the energy from these resources did not provide renewable power for Vermonters. In addition, there are two current programs that predate the RES: The Standard Offer program and net metering. The Standard Offer program began in 2009 and has facilitated contracts for its statutory program capacity of 127.5 megawatts ("MW") of renewable energy. This program underwent several changes since its implementation, with the most notable being an expansion of the initial 50 MW cap and a transition to a competitive procurement process. It is scheduled to sunset after 2023. Net-metering has been available to Vermont electric customers for over 20 years; it started as an avenue for electric customers to reduce electric purchases from the utility with their own on-site generation, but over the years has transitioned to a mechanism that allows electric customers who are able to invest in generation resources and reduce their electric bills. The output from projects built under these programs can be used for RES compliance, depending on the date the project was built.

Based on the experience to date, RES has been successful in reducing GHG emissions while limiting cost implications. This is in part due to program design, and also the fact that the regional framework for tracking renewable attributes was put into place years ago by other New England states that had already adopted similar requirements. In addition to the power supply mandates, the RES requires electric utilities to reduce fossil fuel usage of their customers.

Pursuant to 30 V.S.A. § 8005b, the Department of Public Service ("Department") provides this report addressing:

> (1) The retail sales, in kilowatt-hours ("kWh"), of electricity in Vermont during the two preceding calendar years (§ 8005b(c)(1)).
>
> (2) RES requirements for the two preceding calendar years (§ 8005b(c)(2)).
>
> (3) A summary of the Renewable Energy Credit ("REC") retirements and energy transformation projects costs and benefits for the two preceding calendar years (§ 8005b(c)(3)).
>
> (4) A summary of the Standard Offer program including the technology, number, capacity and average annual generation of the participating projects, and the prices paid. The report also shall identify the number of applications received, the number of participating plants under contract, and the number of participating plants in service (§ 8005b(c)(4)).
>
> (5) An assessment of the energy efficiency and renewable energy markets and recommendations to the General Assembly regarding strategies that may be necessary to encourage the use of these resources to help meet upcoming supply requirements (§ 8005b(c)(5)).
>
> (6) An assessment of whether Vermont retail electric rates are rising faster than inflation, and a comparison of Vermont's electric rates with electric rates in other New England states and in New York. If statewide average rates have risen faster than inflation over the preceding two or more years, then additional assessments shall be included with any recommended statutory changes (§ 8005b(c)(6)).

(7)(A) Commencing with the report to be filed in 2019, an assessment of whether strict compliance with the requirements of sections 8004 and 8005 (RES) and section 8005a (Standard Offer) of this title:

(i) has caused one or more providers' rates to rise faster than the statewide average;

(ii) will cause retail rate increases particular to one or more providers; or

(iii) will impair the ability of one or more providers to meet the public's need for energy services in the manner set forth under subdivision 218c(a)(1) of this title (least-cost integrated planning).

(B) Based on this assessment, consideration of whether statutory changes should be made to grant providers additional flexibility in meeting requirements of sections 8004 and 8005 or section 8005a of this title (§ 8005b(c)(7)).

(8) Any recommendations for statutory change related to sections 8004, 8005, and 8005a of this title (§ 8005b(c)(8)).

Background

Renewable Energy Standard

Section 8 of Act 56 of 2015 created Vermont's Renewable Energy Standard, requiring Vermont's electric distribution utilities ("DUs") to retire a minimum quantity of renewable energy credits ("RECs") or similar attributes, and to achieve fossil-fuel savings from energy transformation projects.[52] [53] The structure of the RES is divided into three tiers.

Tier I requires DUs to retire qualified RECs or attributes from any renewable resource capable of delivering energy into New England to cover at least 55% of their annual retail electric sales starting in 2017. The Tier I obligation increases by 4% every third January 1 thereafter, up to 75% in 2032. Tier II requires DUs to retire qualified RECs equivalent to 1% of their annual retail sales starting in 2017. Tier II-eligible resources include renewable generators with a nameplate capacity of less than 5 MW, commissioned after June 30, 2015, and connected to a Vermont distribution or subtransmission line. The Tier II requirement increases by three-fifths of a percent each year, up to 10% in 2032. Pursuant to Section 8005(a)(1)(C), Tier II resources also count towards a DU's Tier I requirement. Additionally, to the extent that a DU is 100% renewable as of 2018, the DU is not required to meet the annual

[52] 30 V.S.A. § 8005(b).

[53] A REC is the renewable attribute associated with a MWh of generation from a qualified renewable resource. With each MWh of electric generation, an environmental attribute is also created. An eligible renewable resource can qualify its generation in different states such that attributes associated with that resource receive a "REC" designation. The energy (MWh) and attributes (RECs) can be separated and traded independent of each other so that a DU can achieve RES compliance by purchasing RECs and does not necessarily need the physical energy from the renewable resources. RECs are the currency used to demonstrate renewable energy compliance in all New England states. NEPOOL Generator Information System (NEPOOL GIS) is the platform used in New England that tracks the characteristics of all generators in the region. It is in this system that all RECs in the region are created, traded and retired.

requirements set forth in Tier II but is required to accept net-metering systems and retire the associated RECs.[54] [55]

Some existing Vermont renewable programs such as net-metering and Standard Offer help utilities achieve Tier II compliance. Specifically, any net-metering[56] and Standard Offer projects commissioned after June 30, 2015, may qualify as Vermont Tier II resources. The Department estimates that each year roughly 28 to 30 MW of new distributed generation will be needed to meet Tier II between now and 2031 under a business-as-usual load forecast, assuming that Tier II continues to be met primarily with solar resources. Using the Vermont Climate Council's "Central Mitigation Scenario" load forecast where electrification ramps up significantly towards the end of the decade, Vermont would require similar amounts of new distributed generation in the first half of the decade but that quickly ramps up to as much as 57 MW by 2031 to meet Tier II. Given the limited eligibility criteria for Tier II there is not a liquid market for these RECs to date, the necessary Tier II RECs have come from net-metering, Standard Offer, and resources owned by or under contract to utilities. To date, projects associated with existing programs have provided sufficient RECs for Vermont utilities to meet their RES requirements. As RES requirements increase and the Standard Offer program ends, there will be a need for additional Tier II resources. Given the limited eligibility for Tier II projects and lack of a market for Tier 2-eligible RECs, most DUs have chosen to over-procure Tier II resources to avoid paying the ACP.

The implementation of REC retirements for RES Tier I and Tier II compliance is consistent with the rest of the New England states. Starting in 2003, other states in the region began implementing renewable portfolio standards ("RPS"). By 2008, all other states in the region had an RPS to be met with REC retirements or an ACP. During that time, Vermont encouraged renewable development through the Sustainably Priced Energy Enterprise Development ("SPEED") program which required DUs to enter into stably priced long-term contracts, but did not require utilities to serve their load with renewable energy or to retire RECs.[57] The resources built or contracted for through SPEED continue to be in Vermont's power supply mix, and although many do not provide RECs for RES compliance, Vermonters are still paying for the energy and capacity procured under this program.

The REC markets in New England are all related to and driven by state renewable policies and eligibility criteria. "Existing" REC markets (e.g., Vermont Tier I, and Class II or "existing" in other states) are intended to provide incentives to existing resources to remain operational. "New" REC markets (e.g., Vermont Tier II, and regional Class I or "new" in other states) are designed to stimulate renewable development and provide a greater incentive than existing RECs. Vermont Tier I resources include any renewable generator in the region and imports from neighboring control areas (e.g., Hydro Quebec – "HQ" – and New York Power Authority – "NYPA" – hydro). Vermont Tier I RECs are

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[54] Net-metering RECs must be retired per Section 5.127(B)(1) of Rule 5.100 and 30 V.S.A. § 8010(c)(1)(H)(ii).

[55] A utility can also make an Alternative Compliance Payment ("ACP") in lieu of retiring Tier I or Tier II RECs. ACP payments are made to the Clean Energy Development Fund ("CEDF"), which "promotes the development and deployment of cost-effective and environmentally sustainable electric power and thermal energy or geothermal resources for the long-term benefit of Vermont consumers." See 30 V.S.A. § 8015(c).

[56] Net-metering customers elect whether to transfer the RECs to the utility in exchange for a higher compensation rate. The vast majority of customers choose to transfer the RECs to the utility. However, prior to the PUC's change to the net metering rule, there was no provisions regarding the RECs from these facilities and therefore net metering facilities constructed prior to July 1, 2017, are not counted toward Vermont's renewable requirements.

[57] The use of RECs to track renewability is the generally accepted standard across the country.

generally consistent with regional Class II or "existing" RECs in neighboring states, and in their short history, Tier I RECs have traded at similar prices to regional Class II RECs. Since the implementation of renewable standards in the region, there has been excess supply of these types of resources in the region, resulting in prices around $1/REC, however, recent changes in policies such as Massachusetts Clean Energy Standard – which does value existing hydro (including that imported from neighboring control areas transferring power from HydroQuebec, New York Power Authority, or others), has led to notable increases in these REC prices into the high single digits and even low double digit prices ($8-$10/MWh for Maine Class II in 2022). In the region, regional Class I RECs have unique eligibility criteria by state, but generally, new renewable resources qualify, regardless of size, except in Vermont. Vermont Tier II, however, has a much narrower eligibility criteria than other states, and a resource that qualifies as regional Class I in neighboring states will not necessarily qualify as Vermont Tier II.

When there is sufficient supply of Tier II RECs, it is expected that Tier II and regional Class I RECs will trade at similar prices. However, if there is a shortage of Tier II RECs, then Vermont Tier II will trade at a premium to regional Class I in other states. Many Vermont utilities have resources in their portfolio that qualify as regional Class I (high-priced) and Vermont Tier I (low-priced), but not Vermont Tier II, resulting in the out-of-state sale of regional Class I RECs from Vermont resources (e.g., McNeil biomass, Kingdom Community Wind, pre-July 2015 Standard Offer projects, etc.) and the purchase of lower-priced Vermont Tier I RECs from out of state.

Act 56 also created Tier III, which requires DUs to achieve fossil-fuel savings from energy transformation projects or retire additional Tier II RECs. For Tier III, the RES requires savings equivalent to 2% of a DU's annual retail sales in 2017 increasing to 12% by 2032, except for municipal electric utilities serving less than 6,000 customers, which had a delayed start and began their obligation until 2019. Energy transformation projects include weatherizing buildings, installing air source or geothermal heat pumps, biomass heating systems and other high-efficiency heating systems, switching industrial processes from fossil fuel to electric, increased use of biofuels, and deployment of electric vehicles or related charging infrastructure. The Tier III requirements are additional to the Tier I requirements and Tier III compliance can also be met through the retirement of Tier II RECs or payment of an ACP.

To date, Tier III measures have focused on electrification measures—both custom and programmatic. In 2021, 75% of Tier III requirements were met with residential and commercial heat pumps and another 6.5% with electric vehicles. Utilities have reduced fossil fuel usage through various means including line extensions,[58] weatherization, industrial compressed natural gas burners and electric boilers.

Standard-Offer Program

The Standard Offer program, established in 2009, was designed to provide a financing mechanism for small-scale renewable energy projects of 2.2 MW or less by offering renewable resources long-term fixed price contracts with the state, through the Standard Offer program administrator (currently VEPP, Inc.). This requirement was imposed before Tier II and before the above-retail rate solar adder for net metering, when there was a limited amount of distributed renewable generation in Vermont.

[58] Many of these line extensions are related to providing sufficient electric service for a sugaring or sawmill operation to switch away from diesel generators.

The Standard Offer program initially had a 50 MW program capacity that was expanded to 127.5 MW in 2012. 2012 statutory changes set an annual schedule that require the PUC to issue standard offer contracts for varying amounts until the cap of 127.5 MW is reached.[59] Prior to 2012, there was a centralized procurement process and an administratively determined fixed price for all resources within a particular technology category. This approach resulted in rapid deployment of solar resources at a significant cost, with early solar projects receiving $0.30/kWh. In 2012, the program was modified to allow for a market mechanism to set the contract price. Contracts are now awarded to generators annually through a Request for Proposal ("RFP") process which includes a price cap for each technology type including solar, wind, biomass, landfill gas, and food-waste methane digesters, and hydroelectric facilities of up to 2.2 MW.[60] This market mechanism significantly lowered the cost of the program, with projects in 2021 awarded contracts as low as $0.0818/kWh.[61]

Under the program, the Standard Offer facilitator is required to enter into fixed price, long-term contracts for the output of awarded projects. The costs associated with the program, as well as the energy, capacity and RECs from the projects, are allocated to each DU based on their pro-rata share of load.[62] Vermont utilities may use RECs from Standard Offer projects commissioned after July 1, 2015, to satisfy Tier II of the RES. RECs from Standard Offer projects built before this date may be used to satisfy Tier I. However, RECs from Standard Offer projects commissioned prior to July 1, 2015, are generally qualified as regional Class I resources in neighboring states. As described earlier, regional Class I prices are typically similar to Vermont Tier II and therefore significantly more valuable than Vermont Tier I. Therefore, those RECs would most likely be sold out of state as regional Class I RECs rather than used for Tier I compliance in Vermont.

Ryegate

Ryegate is a 20 MW biomass (wood-fired) generator that qualifies for Vermont's Baseload Renewable Energy Standard. Under 30 V.S.A. § 8009, utilities must purchase their pro rata share of the output from Ryegate under a 10-year contract administered by VEPP, Inc. Given the size and age of the plant, RECs generated by Ryegate are not eligible for Tier 2 and are sold outside of Vermont. The current contract was set to expire November 1, 2022; however, Act 155 (S. 161) temporarily extended this obligation for 2 years and also gave the opportunity for a further extension out to 2032 provided Ryegate owners make improvements to the plant efficiency. The fate of this plant is not yet known and contingent on improved heat utilization for another beneficial purpose (also known as co-generation).[63]

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[59] Pursuant to 30 V.S.A. § 9005a(c)(1)(A), "The amount of the annual increase shall be five MW for the three years commencing April 1, 2013, 7.5 MW for the three years commencing April 1, 2016, and 10 MW commencing April 1, 2019."

[60] Standard Offer rates are also available for farm methane digesters. These projects do not count toward the 127.5 MW programmatic cap.

[61] See Public Utility Commission Case 21-4085-INV Order Re: Standard Offer Award Group, 6/28/22. Available at https://vermontstandardoffer.com/wp-content/uploads/2022/06/Case-No.-21-4085-INV-Investigation-to-review-the-2022-implementation-of-the-standard-offer-program.pdf

[62] A utility may seek exemption from the standard-offer program if during the previous year it had renewable energy, through either ownership or contracts, that was not less than its amount of retail sales.

[63] S.161 (Act 155) *An act relating to extending the baseload renewable power portfolio requirement*

As a wood-fired plant, the Ryegate Facility relies upon a consistent supply of biomass from the forest economy. Likewise, many fuel suppliers rely on Ryegate to fill an essential role in the market for forest products – a market with significant impacts on businesses and livelihoods. Several fuel suppliers have recently expressed significant concerns about the state of operations at the Ryegate Facility. The most prominent issues include (1) payment and contracting practices, with some commenters reporting that they are not being paid for deliveries or are owed substantial sums; (2) lack of a certified scale to weigh incoming deliveries; (3) lack of qualified forestry staff; and (4) the impacts of ongoing bankruptcy proceedings associated with Solar Enterprises, Series LLC ("Stored Solar"), Ryegate's owner. The Department has engaged with Ryegate since learning of these issues, to express its concern and underline the importance of addressing the issues, fully and transparently, without delay. Ryegate has acknowledged that it had been behind on payments, and faced difficulties with its payment schedules, but reported that it was current on its outstanding obligations through November 13, 2022. The company also expressed a willingness to enter contracts with suppliers, which had been a standard practice in the past. As to equipment and staff, Ryegate stated that its broken truck scale was due to be repaired and recertified on November 29, and confirmed it has a Vermont-licensed forester with plans for a successor. Ryegate also represents that it is not directly involved in the bankruptcy case, although the proceeding has indirectly affected its operations. There is still significant progress to be made on several fronts, and Ryegate has affirmed its commitment to continuing the work. The Department will continue to closely monitor Ryegate's operations under the contract that has been directed by the General Assembly.[64]

Renewable Energy Standard

RES Performance to Date

Pursuant to the PUC's *Order Implementing the Renewable Energy Standard*, issued in Docket 8550 on June 28, 2016, Vermont utilities must submit annual RES filings by August 31st each year to demonstrate compliance with their obligations. To date, in each year the RES has been in effect, the PUC has found all the utilities to be in compliance with RES obligations[65]. On December 28th, 2022the PUC issued an order in Case No 22-0604-INV concluding all utilities had again met their obligations, noting that utilities demonstrated compliance with Tiers I and II of the RES by retiring RECs in the NEPOOL GIS. For Tier III, utilities submitted compliance claims to the Department on March 15; the Department evaluated and verified Tier III performance and presented those findings in a Tier III Report filed on June 1, 2022 (with a revised report filed July 1, 2022). Table 1 provides an overview of 2021 RES compliance by Tier for each utility in the state.

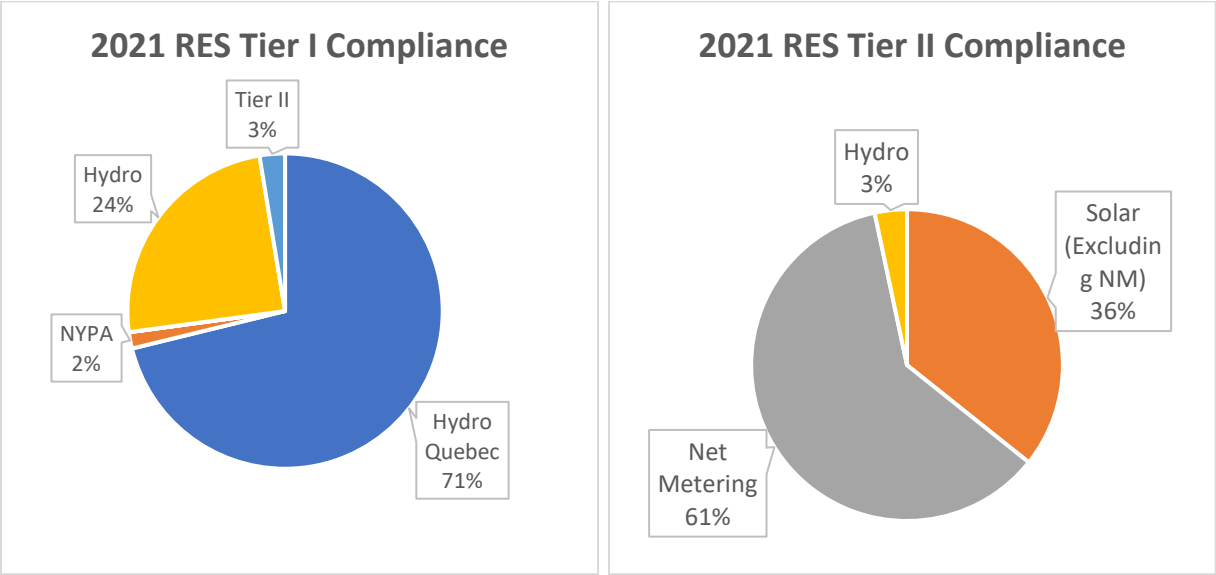
[64] See Public Utility Commission Case No. 22-3944-PET for public comments and more information regarding Ryegate's response.

[65] See Commission Orders in Dockets 17-4632-INV, 19-0716-INV, 20-0644, and 21-1045-IV for 2017, 2018, 2019, and 2020 compliance years.

Utility	2021 REC Retirements and Savings Claims as a Percent of Sales		
	Tier I	Tier II	Tier III[66]
Barton	65.3%	3.4%	5.3%
Burlington	102.6%	0.0%	7.3%
Enosburg Falls	65.3%	3.4%	5.3%
Green Mountain Power	78.8%	3.4%	4.7%
Hardwick	65.3%	3.4%	5.3%
Hyde Park	59.0%	3.4%	3.3%
Jacksonville	65.3%	3.4%	5.3%
Johnson	65.3%	3.4%	5.3%
Ludlow	65.3%	3.4%	5.3%
Lyndonville	65.3%	3.4%	5.3%
Morrisville	65.3%	3.4%	5.3%
Northfield	65.3%	3.4%	5.3%
Orleans	65.3%	3.4%	5.3%
Stowe	59.0%	3.4%	7.5%
Swanton	100.0%	0.0%	5.3%
Vermont Electric Cooperative	59.0%	3.4%	8.7%
Washington Electric Cooperative	107.1%	3.4%	11.4%
Vermont State Total	77.7%	3.2%	5.3%

Table 1. REC retirements as a percentage of retail sales 2020 by utility and RES Tier

In 2021, utilities met their Tier I obligation by retiring RECs from a variety of resources including owned hydro facilities, long-term Hydro-Quebec bundled purchases, regional hydro REC only purchases among others. In 2021, utilities satisfied their Tier II obligations through primarily solar resources including continued growth in net-metering, commissioning of standard-offer projects, and in-state solar, both utility and merchant owned. Figure 1 illustrates REC retirements by resource for both Tier I and II.



[66] Washington Electric Cooperative and Hyde Park used Tier II RECs for part or all of their Tier III compliance. These RECs are counted towards their Tier III obligation and not their overall renewability as measured in Tier I/II

Figure 1. 2021 Tier I and Tier II REC retirements[67]

Vermont utilities met their Tier III obligations with a variety of measures. Over 50 percent of Tier III savings were derived from cold climate heat pumps. The remainder of savings came from custom commercial and industrial projects which were both cost effective and delivered significant fossil-fuel savings, line extensions, and programs to promote electric vehicles and battery storage, among others. Additionally, a small number of Tier II RECs were retired to meet the obligation. Figure 2 shows the breakdown of measures used to meet Tier III requirements in 2021.

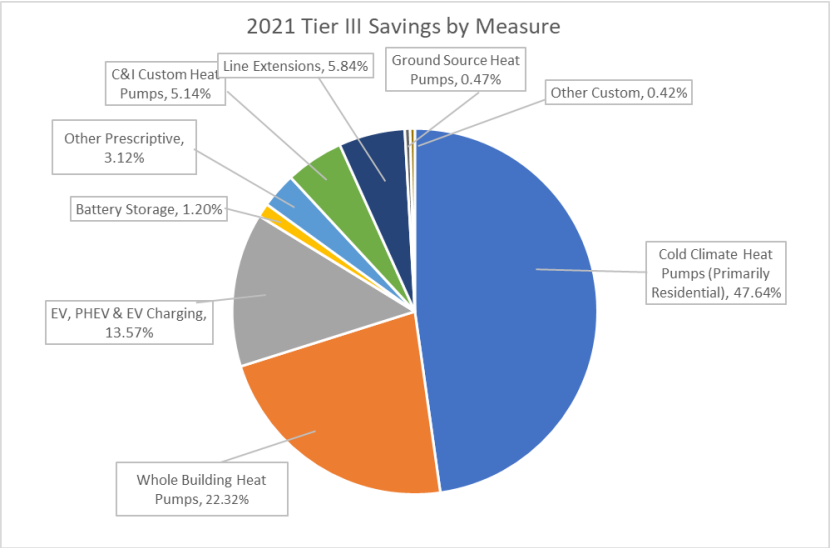


Figure 2. 2021 Tier III compliance measures

Table 2 summarizes key metrics on 2021 RES performance. Compliance costs for 2021 were estimated to be about $17 million, compared to maximum potential costs of $67 million.[68] Carbon Dioxide (CO2) emissions were reduced by approximately 717,019 tons from 2016 emissions.[69] This shift to more owned renewable attributes combined with an increased share from nuclear energy brings Vermont's average emissions rate down to 78.3 pounds of CO2 per MWh compared to the regional New England average of 654 pounds per MWh in 2020.[70]

[67] Tier II is a component of Tier I and many Vermont utilities over-comply with Tier I.

[68] Maximum potential costs reflect what the costs would have been if ACP was paid to meet all 2021 RES requirements.

[69] In addition to CO2 reductions directly resulting from RES, Vermont's electric mix was 18.5% nuclear in 2021 compared to 12.8% in 2016. This increase may be a result of utilities being incentivized to decrease their share of fossil fuel energy for Tier III purposes, but for purposes of this report, the reduction in emissions from increased nuclear has not been categorized as being attributable to RES, except as accounted for in the Tier III credit calculation.

[70] https://www.iso-ne.com/static-assets/documents/2022/05/2020_air_emissions_report.pdf

	2021 RES Performance		
	REC Retirements		*Compliance Cost*
Tier I	4,182,857	RECs	$1,534,625
Tier II	173,623	RECs	$6,208,135
Tier III	283,959	Mwh(e)	$9,198,203
Total Cost of Compliance			$16,940,963
Retail Sales	5,382,695	kWh	
Rate Impact of RES Compliance	1.9%		
CO2 Reduction from RES	717,019	tons of CO2	

Table 2. 2021 RES Performance Metrics

Projections of Future Program Performance

Methodology and RES Model Overview

As in previous years, the Department utilizes a spreadsheet-based scenario-analysis tool (the "Consolidated RES model" or "RES model"). The model was developed by the Department and has been refined over recent years based on market developments and stakeholder input. The RES Model is capable of modeling a range of assumptions regarding energy and REC prices, net-metering deployment, technologies used to meet Tier III requirements and the impact of new Tier III load on peaks.[71] The model is not a forecasting tool, but instead designed to facilitate scenario analyses to explore the range of potential impacts of the Vermont RES, as assessed by criteria such as cost, carbon emission reductions, and rate impact. This section provides a high-level explanation of the key assumptions that the model includes and their influence on the results of the model, which are reported in *Section 4.2 Projected Program Impacts*. Appendices II and III to this report provides additional documentation of the key variables used by the RES model and the values assigned to them in the Department's scenario analyses. Vermont's 2022 Comprehensive Energy Plan recommended that the State "Consider adjustments to the Renewable Energy Standard and complementary renewable energy programs comprehensively, through a transparent and open process." That process is underway, and in doing so Department staff have collected a wide range of interested stakeholders who have an interest in the RES. Department staff sent out the draft model to this stakeholder list of over 400 and received feedback from over a dozen different individuals and organizations. Given the technical nature of this model, staff spent extra time explaining the RES model inputs, definitions, and outputs and provided information on additional opportunities for stakeholders to learn more about renewable markets and regulations to help them better understand the RES in general, and this modeling exercise.

[71] The RES Model is available on the Department's website at: https://publicservice.vermont.gov/content/renewable-energy-standard-reports

Key Model Outputs

The RES Model assesses the potential impact of the RES in Vermont against several key criteria. These include total cost of the RES, rate impact of compliance with the RES requirements, total CO2 reductions (i.e. The cumulative greenhouse gas (GHG) emission reductions derived from meeting RES obligations), and impacts on consumption of electricity, fossil fuels, and total energy. These metrics are estimated under a range of scenarios for the next ten years (i.e., 2022-2031 for this reporting period).

Within the model, compliance costs map to each tier of the RES. Utility payments to acquire RECs from eligible renewable generation resources drive the costs of compliance with Tiers I and II. Tier III compliance costs include incentives paid by utilities to encourage customer adoption of fossil fuel reduction measures, program administration overhead, and the cost to serve any new electric load associated with customer adoption of fossil fuel reduction measures, less the revenue received from additional retail sales. These costs (for Tiers I, II, and III) provide an estimate for the cost of the RES from the utility perspective. Reduced GHG emissions reported are a result of Tiers I, II and III, and do not include other changes in Vermont's energy portfolio.[72]

Loads

Annual RES obligations are based on a utility's retail sales in the compliance year. For the 2022 RES Modeling effort the Department included a modeling sensitivity around load forecasts, developing two forecasts to project potential impacts of the RES: a baseline load forecast and high load forecast.

The **baseline load forecast** references the forecast developed for the 2021 VELCO Long-Range Transmission Plan (LRTP), which includes existing efficiency, net metering and load from electrification measures through 2019 [73]. The baseline LRTP forecast was developed by estimating customer class sales and end-use energy requirements. For the purpose of the RES Model, the Department has made slight modifications to the electrification forecasts to represent more recent data. To forecast additional load from electric vehicle deployment, the Department utilizes the VELCO LRTP high case and for heat pump adoption the Department utilizes data based on analysis done by the Stockholm Environment Institute (SEI) in support of the Comprehensive Energy Plan and Climate Action Plan. This data is consistent with electrification forecast data recently provided to ISO-New England to inform their regional load forecast, and the Department believes it represents both short term expectations and a reasonable expectation of potential expected growth accounting for current policy and programs.

The **high load forecast** references the modeling conducted by SEI using the Low Emissions Accounting Platform (LEAP) model to understand mitigation pathways to achieve Vermont's carbon reduction requirements pursuant to the Global Warming Solutions Act (GWSA). The high load forecast used by the Department is based upon the Central Mitigation Pathway developed to support the Climate Action

[72] Some Vermont utilities over-comply with RES requirements and are 100% renewable, in part, to eliminate Tier II costs and increase emissions savings claims from Tier III. These reduced emissions are included for 2021 emissions accounting because they are known, but the model's 10-year estimates do not assume continued over-compliance

[73] The LRTP can be found at: 2021 LRTP to PUC_FINAL.pdf. Further information can be found at: https://www.velco.com/our-work/planning/long-range-plan.

Plan (CAP)[74]. Similar to the baseline load forecast, the LEAP forecast is developed by estimating customer class sales and end use energy requirements and includes expected demand for electricity from CAP mitigation measures, including electrification of electric vehicles and cold climate heat pumps.[75]

Both the baseline and high load forecasts are adjusted for estimated net-metering growth.

Net Metering Forecast

To model net-metering installation scenarios, the VELCO LRTP forecast was utilized. This results in high net metering deployment rates in the near-term that slow quickly in the mid-2020s as the market becomes saturated and net-metering compensation is reduced. The Department considers this forecast to be a reasonable base case (or "mid" scenario as described in the model). For the "low" scenario, the Department has assumed 50% of this base, and for a "high" scenario, the Department takes the same base scenario out to 2025 but rather than a sharp decline, shows a much more gradual tapering of incremental annual capacity additions out to 2031.

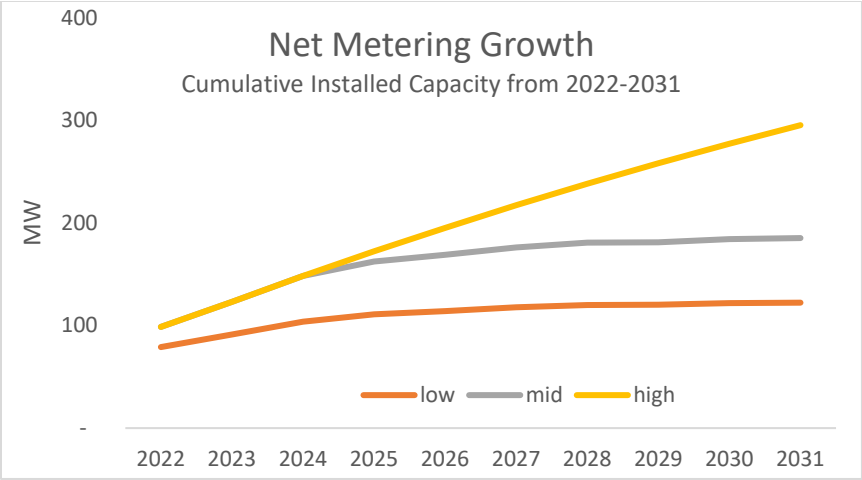


Figure 3. Net-metering growth scenarios

Final Forecast and RES Obligations

Figure 4 shows the comparison between the baseline and high load forecast scenarios under the mid net metering deployment scenario.

[74] Information on the LEAP modeling conducted and the different pathways assessed are available in the *Vermont Pathways Analysis Report*, prepared for the Agency of Natural Resources by EFG and Cadmus. Available here: Draft Vermont Pathways Report. The initial Climate Action Plan can be accessed here: https://climatechange.vermont.gov/readtheplan

[75] The LEAP model has been updated since adoption of the CAP in 2021, and this year's model reflect the latest LEAP modeling Central Mitigation Pathway as of December 14th, 2022.

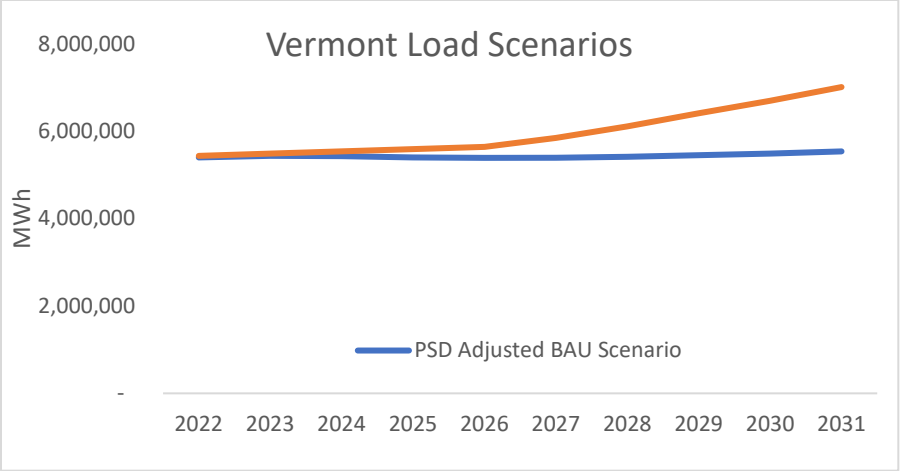


Figure 4. Baseline and high load forecast, 2021-2030

Based on the forecasted loads, the forecasts for Tier I, II and III requirements follow. Figure 5 below shows Vermont's projected retail sales based on the baseline forecast and "mid" net-metering scenario and the related Tier I and II RES requirements through for the 10-year projection period and Figure 6 shows the same data under the high forecast scenario based on the LEAP Central Mitigation Scenario, under the "mid" net-metering scenario.

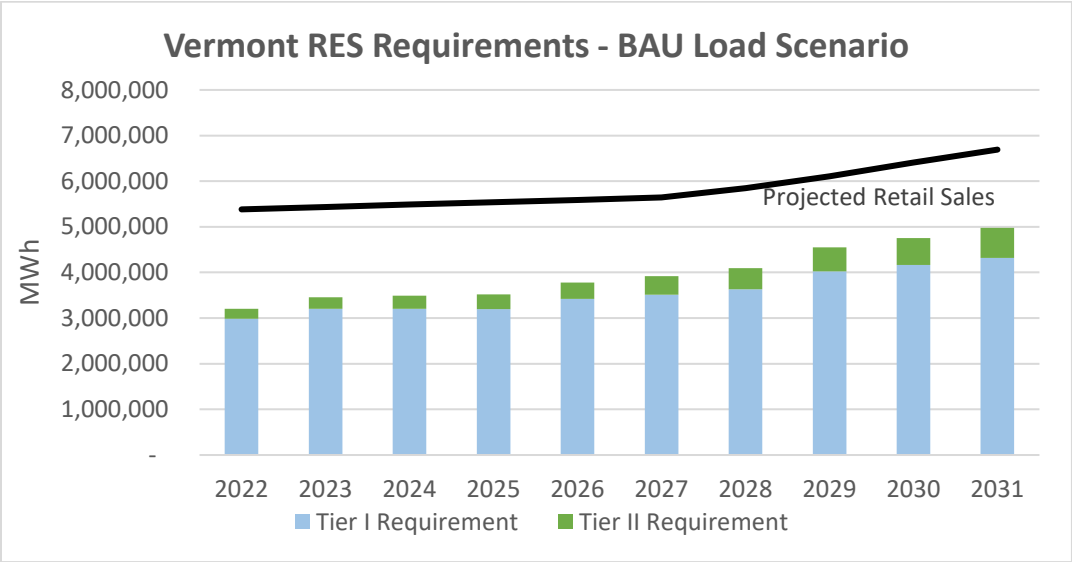


Figure 5. Projected retail sales and RES requirements under the baseline load forecast

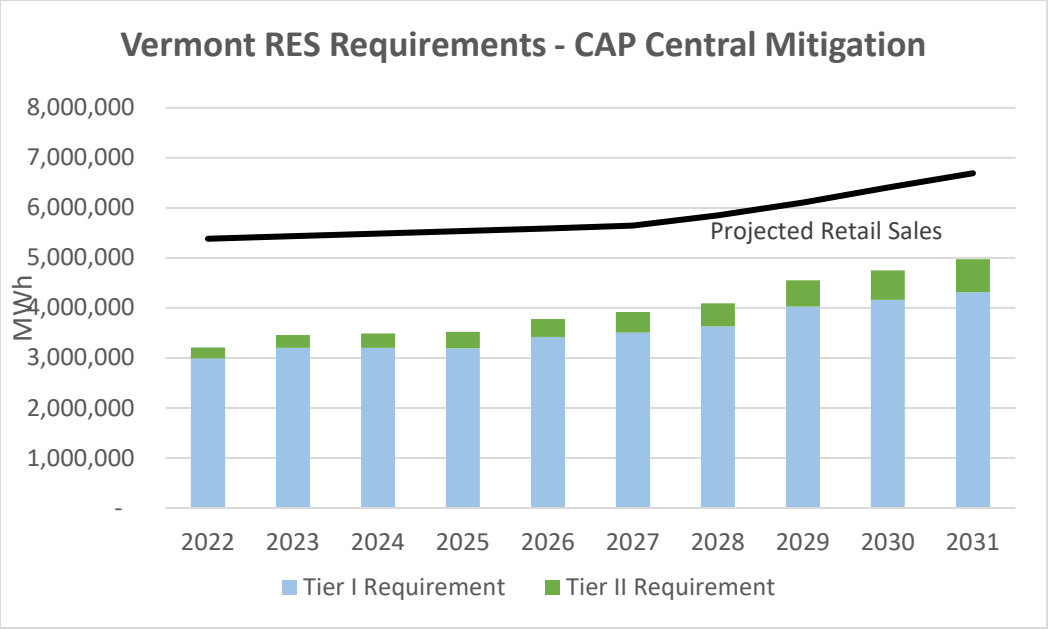


Figure 6. Projected retail sales and RES requirements under the high load forecast

Tier I and Tier II Compliance Costs

Utilities must demonstrate Tier I and Tier II compliance with the retirement of qualified RECs. Absent sufficient RECs, an ACP must be paid to the CEDF. The RES Model makes assumptions about the price utilities will pay to procure RECs to estimate the cost of compliance. For each MWh of generation from qualified renewable resources, a REC is also created. The Department expects Vermont utilities to have sufficient RECs to meet their Tier I and Tier II requirements from a combination of:

1. Net-metered projects that transfer RECs to the utility;
2. Standard-Offer projects, where RECs are transferred to the Standard-Offer Facilitator and then to the distribution utilities;
3. Utility-owned renewable generation;
4. Long-term "bundled" (e.g. Energy, capacity and RECs) Power Purchase Agreements (PPA); and
5. REC-only market purchases.

If a utility does not have sufficient RECs to cover its obligation, in the near-term, PSD expects RECs will be available for purchase at prices less than or equal to the ACP and consistent with premium RECs in other New England states.

The relationships among different regional REC markets informs Vermont REC price forecasts. Vermont Tier I RECs are generally equivalent to Class II or existing RECs in neighboring states, with the exception that imports from Quebec and New York are eligible in Vermont and are only recently included in clean energy standards in other states. Vermont Tier I prices have historically been similar to Class II prices in other states, but that relationship is becoming less obvious as states change what qualifies as renewable and add in other categories of "clean" energy resources for clean energy standards. Vermont Tier II resources are a small subset of Class I or premium resources in other states. As a result, when there is

sufficient Tier II supply in Vermont, excess RECs will be sold as Class I to neighboring states, which results in Tier II prices that are very similar to Class I prices. However, if a shortage of Vermont Tier II resources develops, then prices will diverge with Tier II prices approaching the ACP while Class I prices trade at a different market price.

REC markets provide the opportunity to claim renewability without having to make a long-term commitment of purchasing or generating physical power. However, REC markets can be volatile and illiquid. The ACP, or the price paid when insufficient RECs are retired, acts as a price ceiling for trading prices. The Tier I ACP was $11.97/REC and Tiers II and III were $71.83/REC in 2021; each will escalate annually with the Consumer Price Index. The RES Model includes three REC price forecasts each for Tier I and Tier II markets with the intention of capturing the supply-side volatility.

Tier I REC Prices

Under the current RES, Tier I resources include any renewable generator in ISO-NE and imports from neighboring control areas (e.g., Hydro Quebec, New York Power Authority hydro). This category of RECs has consistently been in excess supply since the inception of renewable standards in the region, as there is no requirement that the eligible resources be new or limited to a certain size, and the RES requirements have been well below available supply. Historically, the demand for these RECs stem from state policy. In recent years, New England has seen an increased drive towards decarbonization, resulting in increased demand for renewable and low- or zero-carbon emitting energy resources. As one result of this shift, additional states are beginning to allow large existing hydropower imports to count towards clean energy requirements and create carve-outs within clean energy and renewable requirements to maintain existing resources. For example, both New York[76] and Massachusetts[77] have modified their Clean Energy Standards to allow utilities and other obligated entities to use existing hydroelectric and nuclear resources to meet clean energy requirements. Further, the Massachusetts Clean Energy Standard – Existing (CES-E) seeks to maintain the contribution of existing clean energy generation units to meeting the state's clean energy and carbon reduction requirements. This, along with increasing demand from the voluntary REC market has begun to drive higher prices for Tier I RECs in 2021. While Tier I RECs have traded around $1/REC in past years, prices have risen to $8-$12/REC in recent months with significant uncertainty regarding the extent to which this trend will persist in the short- and long-term.

Despite the current uncertainty, the Department continues to expect utilities will be able to meet most of their obligations in the near-term with the RECs produced by their owned resources, those they are entitled to by long-term contracts, and the balance from short-term REC only purchases. Figure 7 illustrates the Tier I price forecast utilized in the RES Model. The Tier I base case assumes an average price of around $8.38/REC over the 10-year period, with prices starting at $7.50/REC in 2022 and escalating to $9.14/REC in 2031. The low case starts at the same $7.50/REC price in 2022 then declines to about $5.65/REC in 2031 based on the possibility of new high-voltage transmission lines bringing low-cost hydro power from Quebec down to Southern New England helping those states comply with their Clean Energy Standards.

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[76] State of New York Public Service Commission Clean Energy Standard, Oct. 15, 2020. https://www.nyserda.ny.gov/All-Programs/clean-energy-standard

[77] Massachusetts Department of Environmental Protection 310 CMR 7.75: Clean Energy Standard (CES) Frequently Asked Questions (FAQ) Version 2.1 (October 2022), available from: frequently-asked-questions-massdep-clean-energy-standard/download

The high case averages about $13.78/REC over the period, essentially moving with the Alternative Compliance Payment rate. This scenario represents a future where no high voltage transmission lines bringing Canadian hydro power to Southern New England are completed, driving significant cost increases for these RECs due to scarcity of compliant resources used to meet these state's Clean Energy Standard requirements.

Figure 7. Tier I price scenarios

Tier II REC Prices

Tier II of the RES defines eligible resources as renewable generators with a nameplate capacity of less than 5 MW, commissioned after June 30, 2015, and connected to a Vermont distribution or subtransmission line. These narrow criteria will be a limiting factor on tradable Tier II REC supply going forward and could result in Vermont Tier II RECs trading at a slight premium to other comparable REC markets in the region. The Department expects there to be limited opportunity for utilities to purchase unbundled Tier II RECs. In the near term, utilities will likely continue to meet their Tier II obligations through retiring net-metering and Standard Offer RECs, filling the gaps with RECs trading at similar prices to Massachusetts or Connecticut Class I markets. As RES requirements increase, additional in-state resources will be needed, which may lead to price separation between Vermont and other states. Figure 8 illustrates the Tier II price forecast used in the modeling, showing a range of potential future scenarios. The Tier II base-case assumes an average prices of about $33/REC. The low-case averages $28/REC with significant tapering in the later 5-years reflecting expected new offshore wind projects coming online and helping other New England states meet their obligations. The high-case averages $37/REC for 10 years. This scenario also represents a future where no high voltage transmission lines bringing Canadian hydro power to Southern New England are completed. If large markets such as Massachusetts cannot meet their Clean Energy Standard requirements with hydro power, their next best alternative will be to retire RECs which qualify for both their Clean Energy Standard and Renewable Portfolio Standards (such as solar or offshore wind), which would increase demand and price for these resources.

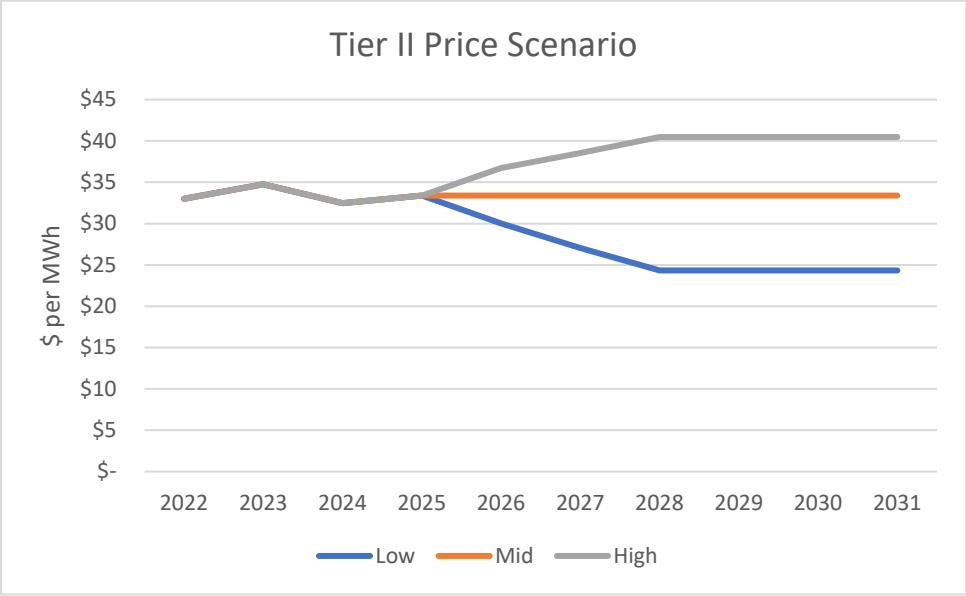

Figure 8. Tier II price scenarios

Calculating the Cost of Tiers I and II

In the RES model, total compliance costs for Tiers I and II are calculated as the product of the assumed cost per REC and the total utility obligation (MWh). The utility obligation quantity is determined by applying the relevant statutory percentage to the annual retail sales forecast. Much of Vermont's Tier I obligation will be satisfied with RECs from existing long-term purchases from Hydro-Quebec (HQ) and the New York Power Authority (NYPA) Niagara Project[78] that come at no additional cost. The forecasted Tier I REC price is then applied to the balance of the obligation.[79] A similar method was applied to Tier II costs, with expected RECs from net-metering being assigned the REC adjustor spread associated with the program, standard-offer RECs assigned a $25/REC price[80], and the balance (purchases or sales) assigned Tier II price forecast. Assuming all else equal, when the load forecast is higher, it follows that the obligations are higher, and therefore compliance costs will also be higher. The factors that most significantly impact obligations and costs are REC prices, net-metering deployment and increases to retail sales, including the extent to which utilities comply with Tier III obligations with measures that increase electric load.

While the RES allows for the banking (of up to 3-years) of excess RECs to then be used for compliance in future years, for simplicity, the Department's analysis disregards banking and assumes that excess RECs in a given year will be sold at market prices to offset total compliance costs. The RES model

[78] The Niagara contract expires September 1, 2025.

[79] Tier I obligations are expected to be met with RECs from owned and purchased renewables. It is assumed that absent RES, utilities would sell the RECs from owned generation at the associated price, so the cost represents the lost opportunity of REC revenue.

[80] This represents the estimated imputed price between the wholesale energy and capacity value and the PPA price paid to the generator.

projects costs assuming that Vermont utilities will meet the RES requirements. However, several Vermont utilities have exceeded RES requirements in the first several years of the RES. Three utilities have continuously demonstrated 100% renewability with the retirement of Tier I RECs, resulting in exemption from their Tier II requirements, and at least one utility has elected to exceed Tier I requirements and achieve a carbon-neutral power supply portfolio voluntarily. The retirement of excess Tier I RECs has come at a low cost, to date. These deviations from explicit RES requirements are not captured in the forward-looking modeling of the RES Model.

Effect of Net-Metering on Obligations and Costs

Net-metering is a financial arrangement whereby a participating customer purchases, leases, or otherwise subscribes to receive credits (currently tied to retail rates with adjustors for siting and REC disposition) for production from a renewable resource—almost always solar—and can use those credits to help offset their electric bills, including carrying them over from season to season for up to a year. Net-metering reduces the volume of electricity that utilities would otherwise sell to ratepayers. Larger volumes of generation from net-metering results in lower load and lower RES obligations for Tiers I, II and III. High net-metering also results in higher power supply costs, lower retail sales revenues, and more RECs from high-priced net-metering projects. Vermont utilities are required to retire RECs associated with net-metering generation, which effectively makes net-metering a carve-out for Tier II. In other words, Tier II requirements are first met with net-metering RECs, and the remaining requirement is met with other Tier II resources. RES could be satisfied at a lower cost with RECs from other resources.

As outlined in PUC Rule 5.100, in 2017 net-metered customers received $0.06 per kWh ($60 per MWh) more for their generation when they transferred their RECs to the host utility, compared to if the customer elected to retain the RECs. In July 2019 the REC adjustor differential decreased to $40 per MWh, where it remains today. Table 3 shows adjustments made to net-metering since 2017.

			RECs		CATEGORY				
Program	CPG Application Date	Statewide Blended Rate	Transfer to Utility	Retain Ownership	I	II	III	IV	Hydro
NM 1.0[81]	before 1/1/2017	$0.149	n/a		n/a				
NM 2.0	1/1/2017 - 6/30/2018	$0.149	$0.03	-$0.03	$0.01	$0.01	-$0.01	-$0.03	$0.00
NM 2.1	7/1/2018 - 6/30/2019	$0.154	$0.02	-$0.03	$0.01	$0.01	-$0.02	-$0.03	$0.00
NM 2.2	7/1/2019 – 2/1/2021	$0.154	$0.01	-$0.03	$0.01	$0.01	-$0.02	-$0.03	$0.00
NM 2.3	2/2/2021 – 8/31/2021	$0.164	$0.00	-$0.04	$0.00	$0.00	-$0.03	-$0.04	$0.00
NM 2.4	9/1/2021 – 8/31/2022	$0.164	$0.00	-$0.04	-$0.01	-$0.01	-$0.04	-$0.05	$0.00

[81] After 2011, and before NM 2.0 (beginning January 1, 2017), systems received overall compensation of $0.19/kWh - $0.20/kWh and retained the RECs. Additionally, other up-front capacity-based incentives were also available.

NM 2.5	9/1/2022 – 6/30,2024	$0.17141	$0.00	-$0.04	-$0.02	-$0.02	-$0.05	-$0.06	$0.00

Table 3. History of net metering compensation, REC adjustors, and project category adjustors

Given the favorable economics of transferring RECs to utilities, the Department expects the majority of future net-metering customers will continue to choose to transfer their RECs, which will then be used by host utilities towards Tier II obligations. Because most DUs expect to have excess Tier II RECs and REC forecasts are currently lower than the REC adder, any sale of excess RECs will come at a net cost to the DUs. The unpredictable pace of net-metering deployment can be difficult to forecast (in large part due to changing rules and tax credits), which has made it difficult for utilities to strategically procure other Tier II resources. As a result, in preparation for the RES, many DUs invested in Tier II-eligible projects or entered into long-term bundled PPAs which, when combined with net metering penetration has resulted in over procurement of Tier II RECs in the short-term. This leads them to sell excess Tier II RECs out of state, sometimes at a loss. Currently, regional premium REC markets are trading around $33/REC so DUs are acquiring net-metered RECs for $40 at a price above what these attributes trade for in other compliance markets. In the scenarios analyzed by the Department for this report, RECs from net-metering generation are more expensive than RECs from all other Tier II sources, which is in line with historical trends and futures projections.

Effect of Tier III Electrification on Tier I and Tier II Obligations

Several eligible Tier III measures offer sources of new load for utilities.[82] The RES model allows the user to specify which Tier III measures utilities will incentivize to meet their obligations. [83] If utilities are assumed to incentivize Tier III measures that build electric load, their retail sales will be higher and thus their Tier I and Tier II obligations will also be higher, but those costs could be offset by increased retail sales revenue. For example, a single passenger electric vehicle that displaces a standard internal combustion engine might use around 2 MWh per year. Higher costs for utilities to serve the additional load would be offset by additional retail revenues from increased electric sales especially if that electric vehicle charges off-peak when cost of serving that load is lower. It should be noted that much of Tier III savings are met with cold climate heat pumps, which contribute new retail sales revenue but can be more costly to serve the same temperature extremes that drive higher heat pump consumption correlate with high energy market prices.

The Department has assumed the following constant allocation of technologies will be used to meet Tier III requirements in each year of the projections:

Tier III Technology Allocation

[82] Tier III measures are represented in the RES Model consistent with the characterizations in the Technical Reference Manual (TRM). The TRM is developed and maintained by the Technical Advisory Group (TAG), of which the PSD is a member. Since the establishment of the RES in 2015, the TAG has been developing calculations that prescribe the amount a given Tier III measure will be credited toward a DU's Tier III obligation, informed by a variety of primary and secondary empirical and engineering studies.

[83] The current version of the RES model includes CCHPs, EVs, weatherization and custom projects as Tier III compliance measure options, in addition to Tier II RECs. For all projections, the technology allocation has been kept constant.

Cold Climate Heat Pumps	50%
Electric Vehicles and Charging Stations	35%
Weatherization	2%
Custom	11%
Tier II RECs	2%

This allocation is intended to be a proxy for the State over 10 years and does not represent forecasted adoptions of each technology. Each utility will likely have a different allocation of measures based on its service territory and customers' needs that will evolve over time. This allocation has been informed by actual Tier III savings performance by measure the previous several years as well as VELCO's 2021 long-range transmission plan's electric vehicle and heat pump adoption modeling.

As an indicative model, this allocation does not consider any other State goals such as those for weatherization, electric vehicles, or the Comprehensive Energy Plan pathways, strategies, or actions, Climate Action Plan pathways, strategies, or actions, recently adopted pursuant to the GWSA[84]. The Department does not expect this to be the actual allocation in each year but uses this illustrative allocation of measures in an effort to quantify the associated additional load and costs. In the first two years of compliance, more than 70% of obligations were met with custom measures and by year three, only 14% of obligations were met with custom projects. In the 2020 and 2021 compliance years, a large percentage of savings were derived from the installation of cold climate heat pumps and electric vehicle adoption as a been relatively lower portion of Tier III savings claims but is expected to grow in the next 10 years. With the current calculation method for Tier III credits where a heat rate is applied to fossil-fuel offset measures, utilities have generally not focused on weatherization because the credits are discounted, and no additional load is gained.

Tier III Compliance Cost Components

Incentive Payments

Fossil-fuel price levels and project incentives are primary influences of customer adoption of Tier III measures. In general, the model assumes the benefits of a Tier III measure must outweigh the costs to justify the investment from the customer perspective. When fossil fuel prices are low, then the cost to own and operate standard fossil fuel equipment (furnaces, boilers, internal combustion engines, etc.) is also low relative to the cost to install, own and operate a substitute Tier III measure. Therefore, in a low fossil-fuel price environment, utilities may need to offer a greater financial incentive to encourage Tier III measures. Conversely, when fossil fuel prices are high, then the cost to operate traditional fossil fuel equipment relative to alternative Tier III measures is also high, and customers may not need as significant of a financial incentivize to invest in a Tier III measure.

The RES model allows for different assumptions about the future price of fossil fuels. In the scenarios analyzed by the Department for this report, three possibilities were explored: a base case assuming current fossil fuel prices will persist in real terms over the next ten years, and high-price and low-price cases that assume by 2031, prices will be 63% higher or 10% lower than they are today. The low fossil-fuel price

[84] https://climatechange.vermont.gov/readtheplan

scenario features utility incentive payments that are 30% higher than the base case, while the high fossil-fuel price case scenario decreases incentives by 10%.

Retail rates are also affected by the fossil fuel scenario. For this analysis, retail rates are assumed to be tied to the market, inflation and depreciation. The portion that is tied to the market is assumed to be 20% of rates, and includes costs associated with energy, capacity, and transmission.[85] Energy prices in New England tend to track closely with natural gas prices such that in the high fossil fuel scenario, wholesale electricity prices reflect higher natural gas prices which then flow through to higher retail electric rates. The opposite is true for the low fossil fuel scenario, which results in lower retail rates.

Program Administration Overhead

Utilities will incur new costs to design, administer and document their Tier III programs. The scenarios the Department analyzed for this report assume these costs will total $1,000,000 in 2022, escalating by 3% thereafter.[86] This represents a small share of the total compliance expenditure in any scenario.

Costs and Revenues of New Tier III Loads

If the Tier III measures incentivized by utilities are sources of new electric load, utilities will incur additional costs to supply and deliver that power to customers, which may be offset by revenues from retail sales at higher rates. The RES model captures the cost of service for new load in energy, capacity, and regional transmission costs. The costs included in this model do not include investments in T&D infrastructure that may be both significant and required to accommodate additional loads. The 2 primary Tier III measures, heat pumps and electric vehicles, have different energy consumption profiles which drive the cost of energy to serve them. Utilities are increasingly deploying time-of-use or managed electric vehicle charging rates to encourage off-peak charging, which help keep the cost of serving these new loads low. Conversely, cold climate heat pumps are highly efficient, but their power consumption tends to peak during high or low temperature extremes – which also correlate with higher energy prices. For this reason, electric vehicles are assumed to have a lower cost of service (0.83 price multiplier) while cold climate heat pumps are assumed to have a higher cost of service (1.10 price multiplier). The incremental costs to provide capacity and transmission is determined by the operations of the Tier III equipment. If Tier III equipment increases peak loads, capacity and transmission costs will be incurred, increasing the cost to serve. Conversely, Tier III loads that are controllable or do not add to peak demand will have much lower costs associated with them. From a policy perspective, most new load associated with Tier III measures should be controllable and not increase peak loads so that they will help to offset other RES compliance costs. The contribution of new Tier III load to peak loads is a variable in the RES model used to test the financial implications of load management. In the Department's base case, 25% of the new load associated with Tier III measures occurs at the peak. The scenario resulting in the low incremental cost of RES assumed 10% of the new load is present at the time of the peak, and the high incremental cost scenario assumed 75% of new load would add to the peak.

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[85] No T&D investments associated with upgrades to accommodate Tier III loads have been included in this analysis.

[86] Actual 2021 overhead costs were reported to be $806,378, however, as programs scale up to meet increasing requirements it is anticipated that overhead will also increase. See Case No. 22-0604-INV for 2021 RES compliance filings made by utilities.

RES Model Results

Considering the variables highlighted in the methodology section, the Department utilized the RES Model to assess future implications of the RES under three different scenarios: a low-cost, base or mid-cost, and high-cost scenario. These three scenarios were each run under the baseline and high load forecast sensitivities, resulting in six scenarios total, which together offer a range of credible outcomes of implementing the RES over the next 10 years. The following sections summarize the results of these modeling efforts with regards to impacts on total energy consumption and CO2 reductions (Section 4.2.1) and total cost of RES and related rate impacts (Section 4.2.2).

Projected Impacts on Total Energy Consumption and CO2 Reductions, 2021-2030

In 2016, before the implementation of the RES, Vermonters directly consumed around 103,000,000 mmBtu of fossil-fuel energy for heating buildings and transportation[87]. Additionally, Vermonters indirectly consumed around 22,000,000 mmBtu of fossil fuel through electric usage.[88] Meeting the RES Tier III obligations requires ongoing reductions in direct fossil fuel consumption (or end-use consumption) of several tens of thousands of mmBtu each year. At this trajectory, the Department estimates that, under the baseline load forecast, end-use consumption of fossil fuels will be about 4,300,000 mmBtu lower in 2031 attributable Tier III, a reduction of 3.4% relative to 2016 levels. Meeting Tiers I and II of the RES will result in ongoing reductions in utility procurement of non-renewable resources, translating to annual reductions of fossil fuel-based electricity. Based on the RES Model, the Department expects the amount of Vermont's electric mix served by fossil fuel will be lower by nearly 15,400,000 mmBtu in 2031, a reduction of 12.4% relative to 2016 levels.[89] Under the high load forecast scenario, the Department estimates the reduction in end-use consumption of fossil fuels attributable to Tier III in 2031 would be around 4,800,000 mmBtu and that consumption of fossil-fuel based electricity in the Vermont mix would have been reduced by nearly 19,500,000 mmBtu, reductions of roughly 4% and 16% compared to total 2016 levels, respectively. Additionally, across both the baseline and high load forecast scenarios, Vermont's portion of electricity from nuclear has increased from 13% in 2016 to 18% in 2021; that share has decreased from a high of 26% with contract expirations, and the Department has assumed that 18% will continue to come from nuclear or other non-fossil fuel sources for the entire projection period.

Overall, across all energy using sectors, the Department estimates that by 2031, on an annual basis, Vermont will consume around 16% less fossil-based energy than it does today in the baseline load forecast scenario, or approximately 20% less in the high forecast scenario, as a direct result of RES, with an additional 1.9% reduction resulting from the increased share of nuclear. Similarly, annual carbon dioxide emissions could be reduced by nearly 1,003,000 tons (baseline load forecast) or 1,224,000 tons (high load forecast scenario) in 2031 as a direct result of RES, a reduction on the order of 12% and 14%, respectively, relative to recent levels across all sectors (estimated to be around 8,600,000 tons[90]), with approximately

[87] http://eanvt.org/wp-content/uploads/2018/06/EnergyActionNetwork_AR_2017_AA_final.pdf

[88] Based on 52% of load from ISO-NE residual mix at an average heat rate of 8,000 mmbtu/MWh

[89] Much of the Tier I savings are a result of purchasing RECs from existing resources, so while Vermont is reducing its fossil fuel consumption, the regional impact on incremental renewable energy is limited.

[90] Vermont Greenhouse Gas Emissions Inventory and Forecast: 1990-2017, published the Agency of Natural Resources, available at: https://dec.vermont.gov/sites/dec/files/aqc/climate-change/documents/_Vermont_Greenhouse_Gas_Emissions_Inventory_Update_1990-2017_Final.pdf

an additional 300,000 tons or 330,000 tons of carbon saving resulting from the assumed increased share of electricity from non-fossil generators in the baseline and high load forecast scenarios, respectively. Valuing these emissions using a Social Cost of Carbon[91] results in approximately $138 million (baseline load forecast) or $169 million (high load forecast) of annual societal benefit in 2031, calculated based on the difference between the amount of electricity attributed to the residual mix in 2016 and 2021. On a cumulative basis, over the period of 2022-2031, under the most likely cost scenario, the Department estimates the RES could lead to over 8,500,000 or 9,200,000 tons of CO2 saved in the baseline and high load forecast scenarios, respectively. This has a net-present value (NPV) of $910 million or $995 million based on the Social Cost of Carbon. Figure 9 illustrates annual estimated carbon reductions for 2022 to 2031 under each of the load forecast scenarios.

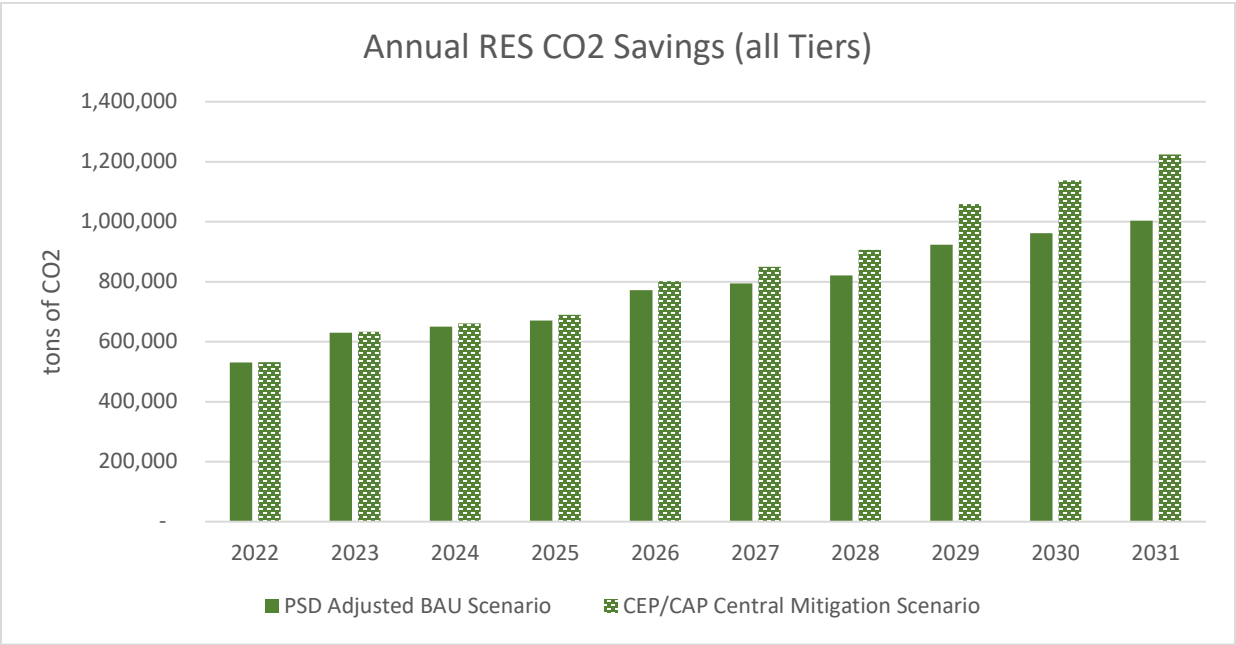

Figure 9. Annual CO2 savings due to the RES from all Tiers, 2022-2031.

Projected Costs of RES, 2021-2030

Using the RES model, the Department finds there to be a wide range of credible outcomes of the total incremental cost of the RES requirements over the next ten years (2022-2031) under the baseline and high load scenarios. Under the baseline load scenario, costs could be as low as $137 million or as high as $271 million (NPV). Under the high scenario projected to meet GWSA requirements, these costs estimates

[91] In 2021, the Science and Data Subcommittee of the Vermont Climate Council recommended that the Social Cost of Carbon under a 2% discount rate would be an appropriate method of reflecting the value of emissions reductions in benefit cost and other economic analyses when assessing mitigation strategies to meeting GWSA requirements. The report and recommendations prepared by the VCC technical consultants, EFG can be accessed here: SCC and Cost of Carbon Report revised.pdf, and Appendix C, *New York Department of Conversation Social Cost of GHG Estimates* provides a reference for the values utilized by the Department for this analysis.

increase to $159 million and $325 million, respectively (Net-Present-Value). These range of costs, for each load scenario, are illustrated in Figure 10, with the baseline (BAU) scenario results presented in lighter color bars and the high results in the darker bars. Based on analysis of the modeling results, the high load scenario generally increases the expected cost of the RES, particularly under the high-cost scenario.

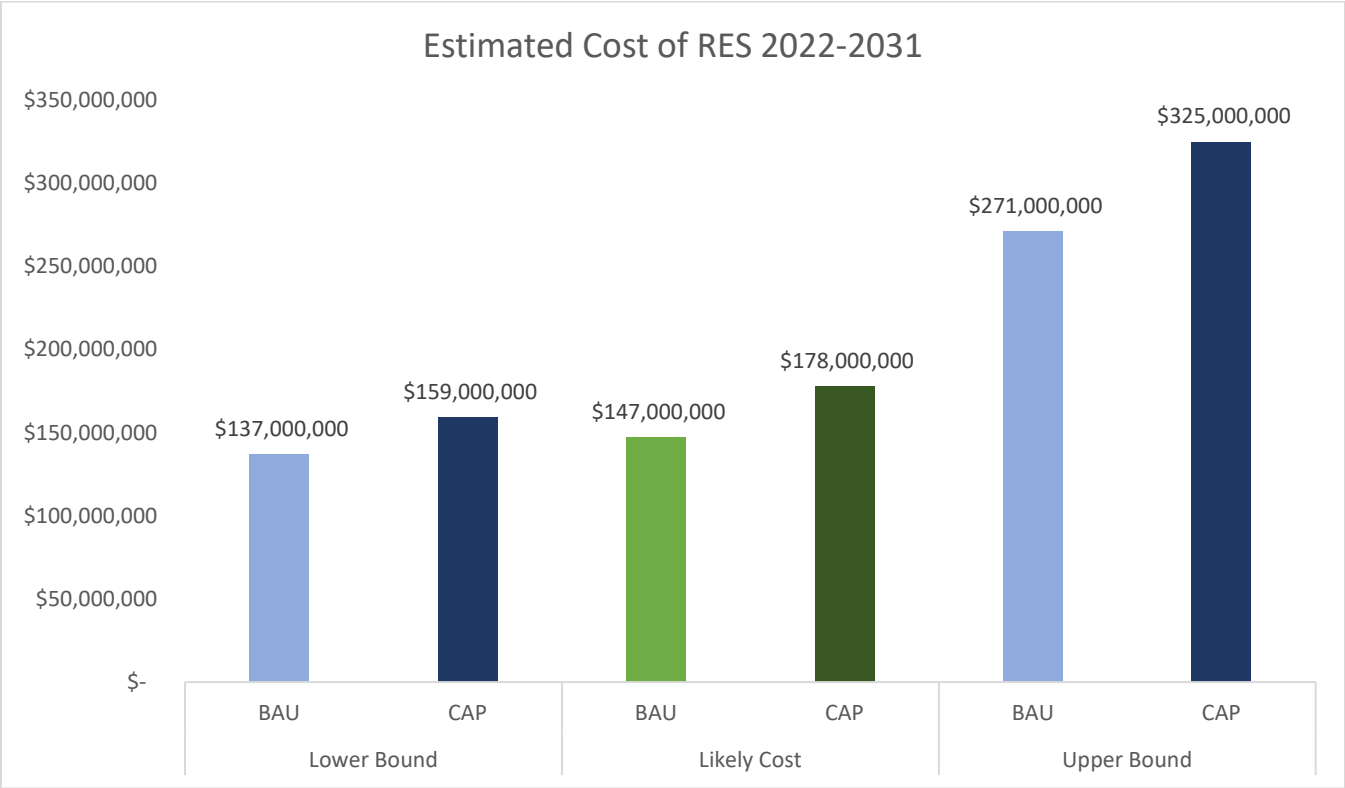

Figure 10. Estimated cost of the RES under the baseline and high forecast load, 2021-2030

As previously discussed in the methodology section, the primary net cost drivers in the model are:

1) Tier I and Tier II REC prices,
2) Net-metering deployment rates and costs,
3) Tier III incentives paid by utilities to customers, and
4) The cost to serve new load associated with Tier III measures.

Table 4 below summarizes what the Department considers credible ranges for each compliance tier over the next 10 years for each of the load forecast scenarios.

	LOW INCREMENTAL COST		HIGH INCREMENTAL COST	
REC Price Scenario	HIGH		LOW	
NM Adoption Rate	HIGH		LOW	
Peak contribution of New Load	75%		10%	
Fossil Fuel Price	LOW		HIGH	
Load Scenario	BAU	CAP	BAU	CAP
Tier 1 Cost	**$64,000,000**	**$76,000,000**	**$119,000,000**	**$150,000,000**
Tier 2 Cost	**$105,000,000**	**$112,000,000**	**$110,000,000**	**$121,000,000**
+Tier 3 Cost	*$254,000,000*	*$271,000,000*	*$324,000,000*	*$350,000,000*
-Additional Revenue	*-$286,000,000*	*-$300,000,000*	*-$282,000,000*	*-$296,000,000*
Tier 3 Net Cost	**-$32,000,000**	*-$29,000,000*	*$42,000,000*	**$54,000,000**
TOTAL Cost of RES	**$137,000,000**	**$159,000,000**	**$271,000,000**	**$325,000,000**
Rate Impact	1.01%	1.19%	4.29%	4.88%

Table 4. Results of RES Model analysis

In 2022 the Department sees that the most significant differences between the upper and lower bounds in the table above are related to Tier 1 costs and Tier 3 costs. The Department expects Tier I compliance costs to be approximately $68 million based on the "most likely" (or mid cost range) assumptions, with a potential range of costs between $64 million (NPV) and $119 million in the baseline load forecast low and high-cost scenarios over the next 10 years. Under the high load forecast scenario, these costs are $87 million ("most likely"), $76 million (lower bound), and $150 million (high bound), respectively. Changes to renewable policies in neighboring states and activity of voluntary REC market players will likely continue to alter the supply and demand landscape for existing renewable RECs that qualify for Tier I, which currently has uncertain implications for prices. That said, Vermont utilities have recently added to their portfolio of long-term contracts with regional hydro generators with prices below current Tier I REC prices, providing an additional hedge against future market volatility. Net Tier 3 costs also present a source of potential variability. These costs would also be influenced by any redesign of the RES intended

to support achieving GWSA greenhouse gas emissions reductions and 2022 Comprehensive Energy Plan goals, as discussed in both the initial Climate Action Plan[92] and the 2022 Comprehensive Energy Plan.[93]

All else equal, to the extent that utilities comply with Tier III obligations by incentivizing load-building measures like heat pumps, electric vehicles, and other custom electrification projects, upward rate pressures associated with RES compliance will be lower than if utilities incentivize non-load building Tier III measures such as weatherization or biofuel-burning equipment. With increased electricity consumption, the costs of meeting the RES requirements can be spread across a greater volume of unit sales and will dampen the rate impacts. In both the low cost and "mostly likely" modeling scenarios, additional revenues associated with Tier III measures result in Tier III having a net negative cost, reducing the total cost of the RES overall. This serves to mitigate upward rate pressure associated with the RES, which will prove important as low electric rates will be critical to successful electrification efforts.

The higher compliance cost-scenarios analyzed by the Department for this report assume that 75% of all new electric load resulting from Tier III measures will add load during times of peak demand. This could be the case if heat pumps and electric vehicle charging do not have custom operational programming or time-of-use controls. On the other hand, if it is assumed that heat pump and electric vehicle loads come online without significantly adding to peaks, it is conceivable that utility compliance with the RES would exert little to no rate pressure over time.

Overall, the Department continues to anticipate that the RES will result in slight upward long-term pressure on retail electric rates. In the scenario the Department considers most likely, the cost of the RES results in approximately 2.1% (baseline load forecast scenario) to 2.4% (high load forecast scenario) rate pressure. But whatever actual RES compliance costs turn out to be, it is certain that ratepayer costs will be mitigated if utilities ensure new Tier III loads come online as flexible demand-side resources that do not significantly add to existing levels of peak demand.

Recommended Changes to the Renewable Energy Standard

As previously discussed, on December 28th, 2022, the PUC has issued an order in Case No 22-0604-INV on 2021 RES compliance, approving compliance for the 2021 compliance year.

The 2022 Comprehensive Energy Plan called for a comprehensive consideration of adjustments to Vermont's Renewable Energy Standard as well as related renewable energy programs – including moving toward 100% renewable or carbon-free electricity, consistent with recommendations contained in the Climate Action Plan. On July 5th, 2022, the Department kicked off a comprehensive review of Vermont's renewable and clean electricity policies and programs. The Department issued a Request for Input ("RFI") to solicit feedback on the process for this review and gathered initial input about what is important to Vermonters regarding the State's supply of electricity. On December 1, 2022, the Department released a proposed public engagement plan to guide a comprehensive review of Vermont's renewable and clean electricity programs and policies over the next year. The proposed plan

[92] https://climatechange.vermont.gov/readtheplan

[93] http://publicservice.vermont.gov/sites/dps/files/documents/2022VermontComprehensiveEnergyPlan_0.pdf

incorporates input received from the Request for Input and envisions three phases of public engagement to implement a core recommendation of the Comprehensive Energy Plan, as illustrated by Figure 11, below.

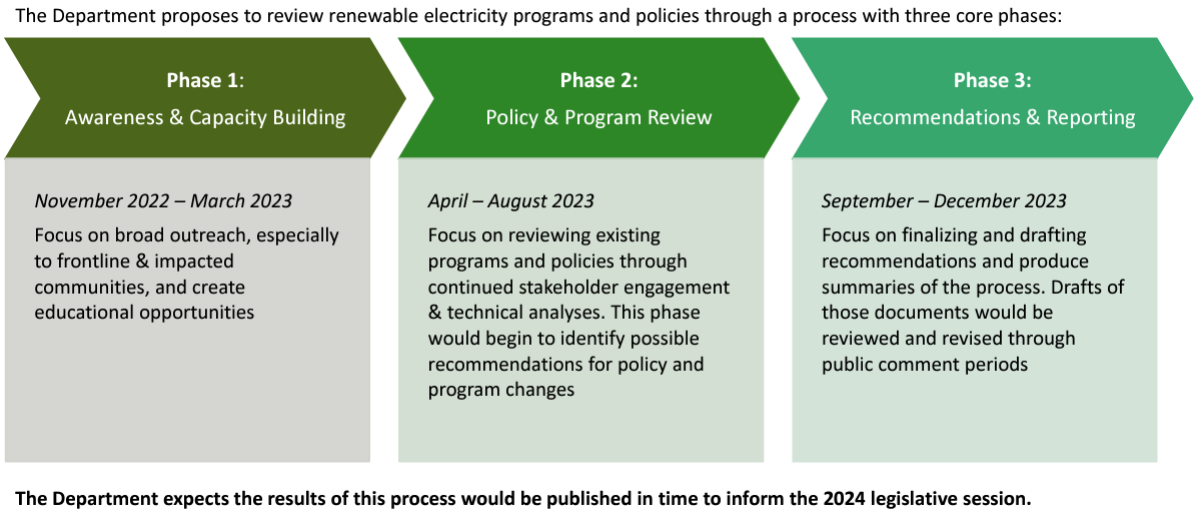

Figure 11. Public Service Department Public Engagement Plan

Attachment 1 – Statutory Reporting Requirement

§ 8005b. Renewable energy programs; reports

(a) The Department shall file reports with the General Assembly in accordance with this section.

(1) The House Committee on Commerce and Economic Development, the Senate Committees on Economic Development, Housing and General Affairs and on Finance, and the House and Senate Committees on Natural Resources and Energy each shall receive a copy of these reports.

(2) The Department shall include the components of subsection (b) of this section in its Annual Energy Report required under subsection 202b(e) of this title commencing in 2020 through 2033.

(3) The Department shall include the components of subsection (c) of this section in its Annual Energy Report required under subsection 202b(e) of this title biennially commencing in 2020 through 2033.

(4) The provisions of 2 V.S.A. § 20(d) (expiration of required reports) shall not apply to the reports to be made under this section.

(b) The annual report under this section shall include at least each of the following:

(1) An assessment of the costs and benefits of the RES based on the most current available data, including rate and economic impacts, customer savings, technology deployment, greenhouse gas emission reductions actually achieved, fuel price stability, and effect on transmission and distribution upgrade costs, and any recommended changes based on this assessment.

(2) Projections, looking at least 10 years ahead, of the impacts of the RES.

(A) The Department shall employ an economic model to make these projections, to be known as the Consolidated RES Model, and shall consider at least three scenarios based on high, mid-range, and low energy price forecasts.

(B) The Department shall make the model and associated documents available on the Department's website.

(C) In preparing these projections, the Department shall:

(i) characterize each of the model's assumptions according to level of certainty, with the levels being high, medium, and low; and

(ii) provide an opportunity for public comment.

(D) The Department shall project, for the State, the impact of the RES in each of the following areas: electric utility rates; total energy consumption; electric energy consumption; fossil fuel consumption; and greenhouse gas emissions. The report shall compare the amount or level in each of these areas with and without the program.

(3) An assessment of whether the requirements of the RES have been met to date, and any recommended changes needed to achieve those requirement

Attachment 2 – Public Comments

Pursuant to the statute, the Department made the RES model and all relevant assumptions public on its website and sought public comments on it. Vermont's 2022 Comprehensive Energy Plan recommended that the State "Consider adjustments to the Renewable Energy Standard and complementary renewable energy programs comprehensively, through a transparent and open process." That process is underway, and in doing so Department staff have collected a wide range of interested stakeholders who have an interest in the RES. Department staff sent out the draft model to this stakeholder list of over 400 and received questions and feedback from over a dozen different individuals and organizations. Given the technical nature of this model, staff spent extra time explaining the RES model inputs, definitions, and outputs and provided information on additional opportunities for stakeholders to learn more about renewable markets and regulations to help them better understand the RES in general, and this modeling exercise. This year, the Department provided a presentation specifically requesting input on key modeling assumptions related energy price futures, Tier I and II REC prices, Tier III measure allocations and incentive levels, along with several other core model assumptions.[94] Comments were received from Green Mountain Power (GMP), Washington Electric Cooperative (WEC), Vermont Public Power Supply Authority (VPPSA), Burlington Electric Department (BED), the Barre Town Planning Commission, Renewable Energy Vermont (REV), and a handful of individual Vermonters.

Many of the utilities who responded (BED, GMP, VPPSA, and WEC) specifically responded to the Department's questions regarding modeling parameters and forecasts. Burlington Electric provided valuable feedback on the cost of serving new cold climate heat pump loads delivered under Tier III programs. BED noted that heat pump energy consumption increases with temperature extremes (hot or cold), and that those weather conditions are highly correlated with high real-time energy prices. The Department agreed with this logic and increased the expected cost of serving cold climate heat pumps from a price multiplier of 1.05 to 1.10. GMP provided specific feedback on Tier I costs, noting that they recently signed a large volume contract for a fixed price at a cost lower than current existing REC resources are trading it, which brings down overall Tier I cost expectations for the forecast period. GMP also provided modest recommended adjustments to Tier II REC prices and wholesale energy prices (draft model too high), and Tier III incentive costs (draft model too low, especially for EVs). VPPSA noted the potential for more sophisticated "Custom" Tier III projects in the future, but that these projects are hard to forecast. The Department agrees this is difficult to model and made a modest 1% increase to the Tier III savings allocation for Custom, bringing the assumed allocation up to 11%. Finally, WEC noted that the portion of total cost of service tied to depreciation (assumed to be 10% in the draft model) may be different for investor-owned utilities than it is for municipal or cooperatives utilities. The Department reviewed depreciation as a percentage of total cost of service from several 2022 rate cases and found the 10% assumption to be a reasonable statewide benchmark (GMP = 10%, BED = 14%, SED = 4% and VEC = 8%). While not a specific issue related to the model, WEC raised issues pertaining to the unfair burden net-metering puts on ratepayers, especially given WEC is already 100% renewable.

[94] https://publicservice.vermont.gov/about-us/plans-and-reports/renewable-energy-standard-reports

While not a direct model input, WEC also noted that the social cost of carbon is undergoing revisions at the Federal level which should be accounted for in broader state climate planning efforts.

The Barre Town Planning Commission provided several comments on broader state energy and climate policy outside the scope of the model such as the impacts of lost forest carbon sequestration due to clear-cutting for solar development. They also asked questions related to the social cost of carbon and whether Regional Planning Commissions would be held to this benchmark in their climate plans, another item outside the scope of this model.

REV provided comments on the need to expand the comprehensiveness of the RES model to account for transmission and distribution impacts from distributed resources. While the Department agrees this is an important cost to consider, these benefits and costs are higher locational-specific and not ideally suited for inclusion in a macroeconomic statewide model. VELCO identifies several hundred million dollars' worth of transmission upgrades that would need to be made under a high solar PV scenario in their 2021 Long-range transmission plan, but these are costs specific to individual service lines that will not all be incurred at the same time (if at all) and difficult to predict with any reasonable certainty.[95] While not required by statute, REV encouraged the Department to complete a full benefit-cost analysis of the RES from both a utility and societal standpoint. Cost-benefit analysis are typically used to determine whether or not to implement a measure or policy, but cost-effectiveness is not a requirement under the RES. REV suggested a consideration of the social cost of carbon benefits of the RES, however, the Vermont Climate Council's cross-sector mitigation subcommittee has completed a project to comprehensively examine the aggregate mitigation potential and cost per ton of emissions reductions of measures included in the 2021 Climate Action Plan's Vermont Pathways Analysis.[96] The Department finds this to be a more appropriate venue for this analysis due to the fact that Vermont's electric mix is generally very clean and further reductions in electric emissions intensity should be considered alongside the broader suite of emissions reduction actions through this Climate Council work. This analysis does include a 100% clean energy requirement as part of the Central Mitigation Pathway. REV also commented on the assumptions related to the cost of net-metering and standard offer RECs, which feed into Tier II prices. The rationale behind these figures is provided in section 4.1.6 of this report. REV also notes that the RES model calculates emissions reductions based on retail sales, rather than total electricity purchases (which include additional loads to cover line-losses). While the Department agrees that this is not a full accounting for Vermont's electric emissions, that analysis is covered by Vermont's greenhouse gas emissions inventory. Given the RES is based on retail sales, the model's calculation of emissions reductions attributable to the RES should also be limited to these loads.

Finally, due to the substantially broader distribution list of the draft model this year, the Department received roughly half a dozen inquiries from individual Vermonters. These were generally questions about state energy policies, rather than comments or feedback on the model itself and were mostly pertaining to III electrification measures. For example, one individual wanted to know whether it is assumed that homes installing cold-climate heat pumps would be weatherized first. The RES model largely takes these assumptions from the Vermont Tier III planning tools and technical reference

[95] https://www.velco.com/assets/documents/2021%20VLRTP%20to%20PUC_FINAL.pdf

[96] https://outside.vermont.gov/agency/anr/climatecouncil/Shared%20Documents/MAC%20Curve%20Deliverable%20Memo%20Clean%20Version.pdf

manual.[97] While not the purpose of the RES model public comment period, the Department did take the opportunity to inform any interested stakeholders in the ongoing comprehensive review of Vermont's clean electricity programs that is actively underway.

[97] https://publicservice.vermont.gov/efficiency/tier-iii-renewable-energy-standard

Attachment 3 – Key Assumptions

The table below documents the key input assumptions in the scenario analyses that produced the Department's compliance cost, rate, energy, and carbon emissions impact projection ranges for what it considers most likely, high, and low-cost scenarios (as discussed in *Section 4.2 Projections of Future Program Performance*). Low and high fossil fuel price levels are relative to a base case assumption that escalates current prices at the assumed rate of inflation. The cost to serve Tier III load does not capture possible local transmission or distribution capital expenses or other retail-level costs. Within the model, wholesale power costs are inclusive of energy charges, capacity charges and regional network service charges. The Department has constructed the below scenarios to represent what it considers realistic higher and lower cost scenarios, in addition to a "most likely" middle case to illustrate the range of credible outcomes of the RES. Each of these three cost scenarios were analyzed under the two load forecast sensitivities.

	Higher Cost / Rate Impact	Base Case ("Most Likely") Assumptions	Lower Cost / Rate Impact
General Assumptions			
Inflation Rate	+4%	+4%	+4%
Customer Discount Rate	6.0%	6.0%	6.0%
Tier III Load Profile	75% Peak Contribution	25% Peak Contribution	10% Peak Contribution
Net-Metering Deployment	567 MW by 2031	457 MW by 2031	394 MW by 2031
Tier I REC Price	Avg $13.78/MWh	Avg $8.38/MWh	Avg $5.95/MWh
Tier II REC Price	Avg $37.08 /MWh	Avg $33.39/ MWh	Avg $28.80/MWh
Energy Price Assumptions			
Fossil Fuel price scenario	Low	Mid	High
Fossil Fuel price trend	-1%/yr	1.6%/yr	+5.0%/yr

Appendix C

REPORT ON VERMONT NET-METERING PROGRAM

A Report to the Public Utility Commission and the Vermont General Assembly Pursuant to 30 V.S.A. § 8010.

Prepared by the Department of Public Service

January 15, 2023

Overview

Vermont's net-metering program has changed considerably since it was first authorized in 1998. Early iterations of the program were designed to incentivize small-scale (15 kW) projects that were used to offset the onsite electric consumption of the net-metering customer (i.e., "spin the meter backward"). Under the current program, projects can be up to 500 kW, and there is no requirement that a net-metered project's production physically offset a customer's load – although projects directly tied to a customer's usage usually receive slightly higher compensation. In 2021, just over 75% of the generation produced by net-metered generators was exported directly to the grid and not used onsite, with participating customers receiving monetized bill credits for that exported generation. In effect, net-metering has become a financial construct that allows customers to offset their electric bills by supporting the development of a net-metered system.

This program model has resulted in a significant expansion of the amount of distributed renewable generation in Vermont and helped increase the number of clear energy jobs in the state. However, as with any state-mandated program, it is essential to periodically evaluate whether the benefits associated with the program are commensurate with costs and determine whether those benefits and costs are allocated fairly. As the amount of net-metering has grown to over 32% of Vermont's peak load, it has become clear that the current structure of net-metering will need to be modified to reduce the financial impacts on non-net-metered customers and to help advance Vermont's transition to a low-carbon economy.

Under the current net-metering structure, new participating customers are compensated at their retail rate for own-use generation (generation offsetting load in real time or within a billing period) and the applicable blended residential rate for excess generation (generation in excess of consumption within a month for on-site systems, and all generation for "virtual" or off-site systems). The statewide blended residential rate is currently $0.17/kWh. This rate is effectively modified by adjustors for REC disposition and siting (see Table 1 below). A residential project or one up to 150 kW on a preferred site, transferring RECs to the interconnecting utility, will be effectively compensated at around $0.15/kWh. Larger net-metered projects, and those not on preferred sites, will be compensated at$0.11/kWh to $0.12/kWh. Outside of the net-metering program (e.g., the Standard Offer program and bilateral contracts with utilities), new solar resources are being built for a cost well under $0.10/kWh, including RECs.

While the differential between net-metered and other renewable resources has shrunk in the last several years (for new projects), it still exists, and it is important to keep in mind that all electric customers are paying this premium. However, since net-metering customers have reduced their electric bills, they do not experience the brunt of this cost-shift to the same degree as customers who do not have net-metering systems or credits. Customers have the right to manage their electric usage, including through on-site generation, to reduce purchases from their electric utility. However, there is no corresponding right to have other electric customers subsidize this practice; and with increasing adoption of heat pumps and electric vehicles, net-metering is

starting to result in Vermonters paying for the heating and transportation costs of net-metered customers in addition to the electric costs.

New renewable generation can be procured in multiple ways, and almost all other options come at lower cost than the current net-metering program. A net-metering program that would promote Vermont's clean energy goals in an equitable manner would be structured to allow participating customers to offset on-site consumption in real time and receive compensation for the generation exported to the grid *at the value of that generation to other electric customers*, since at that point, it is a supply resource like any other. *T*his structure would return the net-metering program to its roots of incentivizing customers to offset their onsite energy usage and would better align the net-metering program with promotion of distributed, flexible, beneficial loads.

History of Net-Metering in Vermont

In 1998, Vermont enacted net-metering, requiring electric utilities to permit customers to generate their own power from small-scale renewable energy systems of 15 kW or less. Farms could have larger, anaerobic digesters systems up to 100 kW. The utilities were required to allow net-metering up to 1% of their 1996 peak demand, and any excess power (not consumed on site) generated by these systems could be fed back to the grid, running the electric meter backwards. Excess generation rolled over month to month as kWh but was zeroed-out on December 31.

The net-metering statute was changed in 1999 and almost annually after that, with major modifications in 2001, 2007, 2012, and 2014. These changes included:

- Raising the percent cap of net-metering to 2%, then 4%, then to 15% in 2014.
- Increasing the allowed net-metering system capacity to 150 kW, then 250 kW, then 500 kW in 2011.
- Allowing for credits to roll forward on a 12-month basis. In 2012, the kWh credits were changed to monetary credits and applied to non-energy charges on the electric bills, including monthly service charges, reducing some customers' bills to $0.
- Group net-metering was initially restricted to farmers and their meters. In 2007, group net-metering was expanded to all customers as long as the group members were contiguous. Group net-metering was eventually made available to all customers within a service territory.
- Established a simplified registration and permitting process for systems under 5 kW. This was expanded to 10 kW, then 15 kW, and in 2017 to 150 kW for roof-mounted systems.
- Created a solar adder of up to $0.06/kWh for all solar net-metered systems (based on the solar adder GMP had been paying to solar net-metered systems in its territory). The legislation required the solar adder be paid for ten years from the commissioning of the

system and initiated a Commission process to determine the compensation framework for net-metering going forward.

Act 99 of 2014 moved net-metering out of the statutes and created a regulated net-metering program administered by the Commission. The Commission was charged with putting a new "Net-Metering 2.0" program in place in 2017.

In 2017, the Commission established new rules for net-metering as required by Act 99. Notably the new net-metering program eliminated the cap of net-metering and the solar adder and created siting adjustors for projects on so-called preferred sites and REC adjustors for projects that transfer the RECs to the utility (before 2017, RECs were owned by the customer by default).

Rates, Deployment, and Technology Types

Rates

Since net-metering 2.0 ("NM 2.0" or "NM 2.X") was first implemented in 2017, the compensation rates have been periodically evaluated and adjusted to ensure that the requirements set forth in the statute are met. Specifically, the net-metering statute, under 30 V.S.A § 8010(c)(1), requires the Commission to promulgate rules that establish and maintain a net-metering program that:

- (A) advances the goals and total renewables targets of [30 V.S.A. Chapter 89] and the goals of 10 V.S.A. § 578 (greenhouse gas reduction) and is consistent with the criteria of subsection 248(b) of [Title 30];
- (B) achieves a level of deployment that is consistent with the recommendations of the Electrical Energy and Comprehensive Energy Plans under sections 202 and 202b of [Title 30] . . . ;
- (C) to the extent feasible, ensures that net-metering does not shift costs included in each retail electricity provider's revenue requirement between net-metering customers and other customers;
- (D) accounts for all costs and benefits of net-metering, including the potential for net-metering to contribute toward relieving supply constraints in the transmission and distribution systems and to reduce consumption of fossil fuels for heating and transportation;
- (E) ensures that all customers who want to participate in net-metering have the opportunity to do so;
- (F) balances, over time, the pace of deployment and cost of the program with the program's impact on rates; and
- (G) accounts for changes over time in the cost of technology; and
- (H) allows a customer to retain ownership of the environmental attributes of energy generated by the customer's net metering system and of any associated tradeable

renewable energy credits or to transfer those attributes and credits to the interconnecting retail provider, and:

- (i) if the customer retains the attributes, reduces the value of the credit provided under this section for electricity generated by the customer's net metering system by an appropriate amount; and
- (ii) if the customer transfers the attributes to the interconnecting provider, requires the provider to retain them for application toward compliance with sections 8004 and 8005 of this title.

Table 1 below summarizes net-metering compensation rates over time.

			RECs		CATEGORY				
Program	CPG Application Date	Statewide Blended Rate	Transfer to Utility	Retain Ownership	I	II	III	IV	Hydro
NM 1.0	before 1/1/2017	$0.149	n/a		n/a				
NM 2.0	1/1/2017 - 6/30/2018	$0.149	$0.03	-$0.03	$0.01	$0.01	-$0.01	-$0.03	$0.00
NM 2.1	7/1/2018 - 6/30/2019	$0.154	$0.02	-$0.03	$0.01	$0.01	-$0.02	-$0.03	$0.00
NM 2.2	7/1/2019 – 2/1/2021	$0.154	$0.01	-$0.03	$0.01	$0.01	-$0.02	-$0.03	$0.00
NM 2.3	2/2/2021 – 8/31/2021	$0.164	$0.00	-$0.04	$0.00	$0.00	-$0.03	-$0.04	$0.00
NM 2.4	9/1/2021 – 8/31/2022	$0.164	$0.00	-$-0.04	-$0.01	-$0.01	-$0.04	-$0.05	$0.00
NM 2.5	9/1/2022 – 6/30/2024	$0.171	$0.00	-$0.04	-$0.02	-$0.02	-$0.05	-$0.06	$0.00

Table 1: Net-metering programs and rates

The net-metering rates – historical, current, and future – aim to strike a balance among the goals of the program. As conditions related to renewable technology, costs, the economy, and environmental goals shift, it is appropriate to reevaluate net-metering rates and make appropriate adjustments to achieve these goals at the lowest feasible cost, consistent with Vermont's least-cost planning framework.

Net-Metering Installed Capacity

While the net-metering program is open to a variety of technologies and fuel sources, as illustrated in the chart below, actual installations have been dominated by solar. Of the 324 MW of currently installed net-metering, almost 314 MW, or 98%, is solar, 1.5% is hydro (primarily pre-existing resources), and the remaining 0.5% is split between wind and biomass.

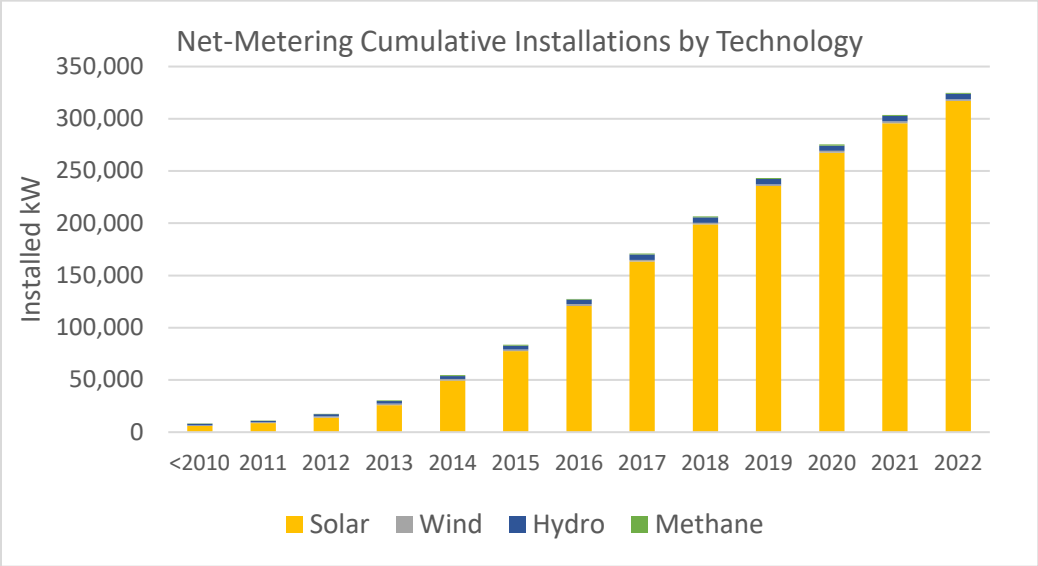

Figure 50: Cumulative net-metering installations by year[98]

All Vermont utilities host net-metering projects. Green Mountain Power has the greatest share of projects, with 84% of Vermont's total capacity, exceeding its 76% share of the state's load. Burlington Electric Department, Vermont's mostly densely populated service territory, hosts just 1.7% of the state's net-metering capacity while serving 6% of the load. Table 2 below shows the distribution of net-metering installations among utilities.

Utility	Total Installed NM (kW)	2019 Non-Coincident Peak	NM as % of Peak Load	Percent of NM Capacity	Percent of Retail Sales
Green Mountain Power	221,266	684,450	32%	84.2%	76.4%
Vermont Electric Cooperative	20,720	80,082	26%	7.7%	8.4%
Vermont Public Power Supply Authority	10,251	71,019	14%	4.0%	6.4%
Burlington Electric Department	4,718	63,076	7%	1.8%	6.0%

[98] 2022 data only through October

Washington Electric Cooperative	3,722	16,067	23%	1.4%	1.3%
Stowe Electric Department	1,645	17,655	9%	0.6%	1.4%
Hyde Park Electric	528	3,370	16%	0.2%	0.2%
TOTAL	**262,850**	**909,433**	**29%**		

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TOTAL	262,850	909,433	29%		

Table 2: Net-metering deployment by utility

Net-Metering RECs

The current net-metering compensation structure provides an effective incentive for customers to transfer the RECs to the utilities. Net-Metering 1.0 did not differentiate compensation based on REC disposition. As a result, more than 98% of Net-Metering 1.0 projects retained the ownership of RECs and those projects cannot be claimed as renewable by Vermont utilities to be used for RES compliance. Compensation rates for Net-Metering 2.0 and beyond have had up to a $0.06/kWh differential between a system owner retaining (and potentially selling RECs in the regional REC market) versus transferring them to the utility. The current differential is $0.04/kWh, which still appears to decisively encourage REC transfers with more than 97% of

RECs being transferred to utilities in 2020 and 2021, consistent with prior years of NM 2.0. In the 2022 Biennial Review, the Commission maintained the $0.04/kWh differential.

In 2018, net-metering RECs accounted for about 17% of utility Tier II compliance.[99] By 2021, with more systems online, net-metering RECs accounted for 66% of Tier II compliance.[100] As additional projects are built and transfer RECs to the utility, RECs from net-metering projects will continue make up a large share of Tier II compliance.

The Department expects 28 to 30 MW of new distributed generation will be needed annually to meet increasing Tier II RES requirements between 2022-2031 under a business-as-usual forecast, if the majority of Tier II compliance continues to be met by solar resources. Higher electrification scenarios would lead to more load, and proportionally higher Tier II RES requirements, reaching as high as 57 MW by 2031. Compliance can come from a variety of project types, from net-metering to Standard Offer to utility-owned and -contracted projects, in order to meet the RES requirements in the most cost-effective manner. Consistent with 30 V.S.A. §§ 202(b), 218c, 8001, 8010(c)(1)(F) and Vermont's least cost planning rubric, the highest priority should be ensuring that the state's renewable energy policies continue to deliver renewable energy at least cost. Currently, net-metering is the most expensive means for utilities to meet the Tier II requirements, and the current structure is a barrier to realizing greenhouse gas reductions – and to achieving the goals of the Vermont Electrical Energy and Comprehensive Energy Plans – because higher power supply costs lead to higher electric rates and electricity must be affordable to encourage fuel-switching for heating and transportation end uses.

The Department notes that installation costs continue to decrease, though at more modest rates than previously experienced. From 2009-2014, installed prices saw significant annual declines, but these have since tapered off. The decreasing REC and siting adjustor compensation rates have thus been partially offset by the decreasing installation costs and higher retail rates, making net-metering profitable for both participating customers and developers over the years. Looking forward, solar installation costs are expected to continue to see declines like those experienced in recent years.[101]

Other Net-Metering Technologies

Net-metering is available to renewable facilities in Vermont that have a capacity of 500 kW or less. The current net-metering rule allows for existing resources that meet net-metering eligibility requirements to convert that system into a net-metering system. This applies to existing facilities that do not need the additional compensation that net-metering provides and do not provide Tier II RECs for RES compliance. For example, several hydroelectric projects that

[99] In 2018 13,765 net-metering RECs were retired for compliance and an additional 5,629 RECs were banked and used for 2019 compliance. If all 2018 generated RECs were used for 2018 compliance, net-metering would have accounted for 24% of Tier II compliance.

[100] In 2019, the 5,629 vintage 2018 RECs were used for 2019 compliance along with 52,395 vintage 2019 RECs. In addition, 3,437 vintage 2019 RECs were banked for used in future years.

[101] https://emp.lbl.gov/sites/default/files/2_tracking_the_sun_2022_report.pdf

had contracts under Rule 4.100 that have expired are eligible for net-metering, although they are not providing new renewable power and the long-term contracts previously received should have paid most or all the initial capital costs of the project.

Economic Impacts of Net-Metering

Cost of Net-Metering

The net-metering compensation rates over time are summarized above in Table 1: Net-metering programs and rates. Each biennial review by the Commission has resulted in gradual decreases to the compensation rate, but net-metering remains one of the highest-cost renewable resources. Based on data collected from each utility, the cost of net-metering in 2021 was more than $49 million higher than the market value of the products provided, resulting in an inequitable cost-shift from participating net-metering customers to non-participating customers.[102] As previously noted, the large majority of net-metered projects are solar, so the Department's analysis of the costs and benefits of net-metering focus on that technology. Below, Table 3 shows the total net-metered generation and above-market costs in 2021 as reported by each utility.

Utility	Reduced Retail Sales (kWh)	Excess Generation (kWh)	Gross Generation (kWh)	Net Metering Above Market Cost	Rate Impact
BED	1,347,383	4,064,135	5,397,580	$655,326	1.4%
GMP	66,296,018	243,993,774	310,289,792	$43,393,505	6.5%
Hyde Park	178,737	146,114	324,851	$42,497	1.8%
Stowe	1,725,790	14,371	1,740,161	$215,740	1.8%
VPPSA	1,869,263	11,584,665	13,453,928	$1,569,202	3.0%
VEC	11,641,896	11,869,254	23,511,150	$2,642,267	3.5%
WEC	4,567,842	799,144	5,366,986	$717,768	4.2%
TOTAL	**87,626,929**	**272,471,457**	**360,084,448**	**$49,236,305**	5.6%

Table 3: 2021 net-metering generation and above market costs

As shown in the table above, utilities must absorb a significant amount of "excess generation" from net-metered projects. When the profile of the generation does not match a customer's load shape (or is not directly serving their load), the customer must rely on the grid to serve or balance their physical energy needs. At times when the generation is insufficient to meet

[102] This figure represents the costs and values of solar projects in 2021, treating generation from all net-metering projects equally. In recent years, the high adoption of solar in Vermont, and throughout New England, have effectively flattened loads and shifted peak hours. Therefore, projects that came online 10 years ago provided a greater value than projects that came online one year ago. This analysis does not assign a greater value to first-generation projects.

demand, electricity is delivered from the grid. At times when generation is greater than on-site demand, the excess is pushed onto the grid – this is called excess generation.[103] Due to the predominance of solar as a net-metering resource and its seasonal nature, some of the highest generation occurs at times with the least demand. For example, in May, when days are long, and temperatures are moderate, solar is producing the most and demand for electricity is already very low. Additionally, group net-metering allows several customers to share the output of a single larger project, for which all the energy is exported to the grid. The result is significant amounts of excess generation. Customer generation that serves on-site load reduces the utility's need to purchase energy as well as reducing the burden on the distribution system. Excess generation, on the other hand, is essentially a power supply resource that utilities must purchase, but it does not provide the same distribution benefits as generation that is consumed onsite – unless it happens to be located very close to load centers.

In 2021, more than 75% of total net-metered generation was excess and exported to the grid. This does not count "real-time" excess from onsite systems, which is treated as reduced retail sales as long as it nets consumption within the month it is generated. Credits for excess generation totaled more than $57 million in 2021 with the generation valued at $23 million. If net-metering systems are appropriately sized such that most of the generation is consumed onsite, or if excess generation were compensated based on the value provided as proposed by the Department in Docket 19-0855-RULE, then the cost-shift caused by net-metering would be greatly reduced.

Impact on Retail Revenue

The extent to which net-metering costs have impacted Vermont utilities' revenues and retail rates varies. As described above, net-metering systems cost more than the value they provide. Additionally, net-metering reduces the utility's retail sales without reducing fixed costs; therefore, there are fewer MWhs to spread the costs over, resulting in higher retail rates for all customers. On average, in 2021, net-metering is estimated to have caused 5.6% of electric rate pressure (see Table 3 above).

Going forward, the impact of net-metering should taper off as the older and most expensive systems reach the end of their 10-year adder or positive adjustor incentives and revert to the current net-metering tariffs, and new projects have lower compensation rates.

[103] Excess generation figures are based on the current net-metering convention of monthly netting of a customer's excess production (anything not used in real-time) with their consumption from the grid. Therefore, under this convention, excess after monthly netting from customer-sited systems, and all generation from "virtual" systems that are located elsewhere from associated customers, is counted as excess.

Economic Benefits of Net-Metering

Early in the net-metering program, new solar projects effectively shifted the peak hour, and reduced load at the time of peaks, resulting in reduced capacity and transmission costs. However, the benefits provided by new and future net-metering projects have diminished as the peak shifts into the evening, where solar can no longer contribute. Regional capacity and transmission ("RNS") costs are allocated based on a utility's load at the time of the system peak load. As more solar comes online, and peak hours shift later in the day to hours when solar is not generating, the value of new solar has been eroded. Most monthly statewide peaks (the basis for RNS charges) have moved to after dark. Capacity peaks have moved to the 5 p.m. Or 6 p.m. Hour, when solar output is diminished. Energy prices are highest in winter months. Compared to other available renewable resources in Vermont, the cost of net-metering is significantly higher, as shown in Figure 2.[104]

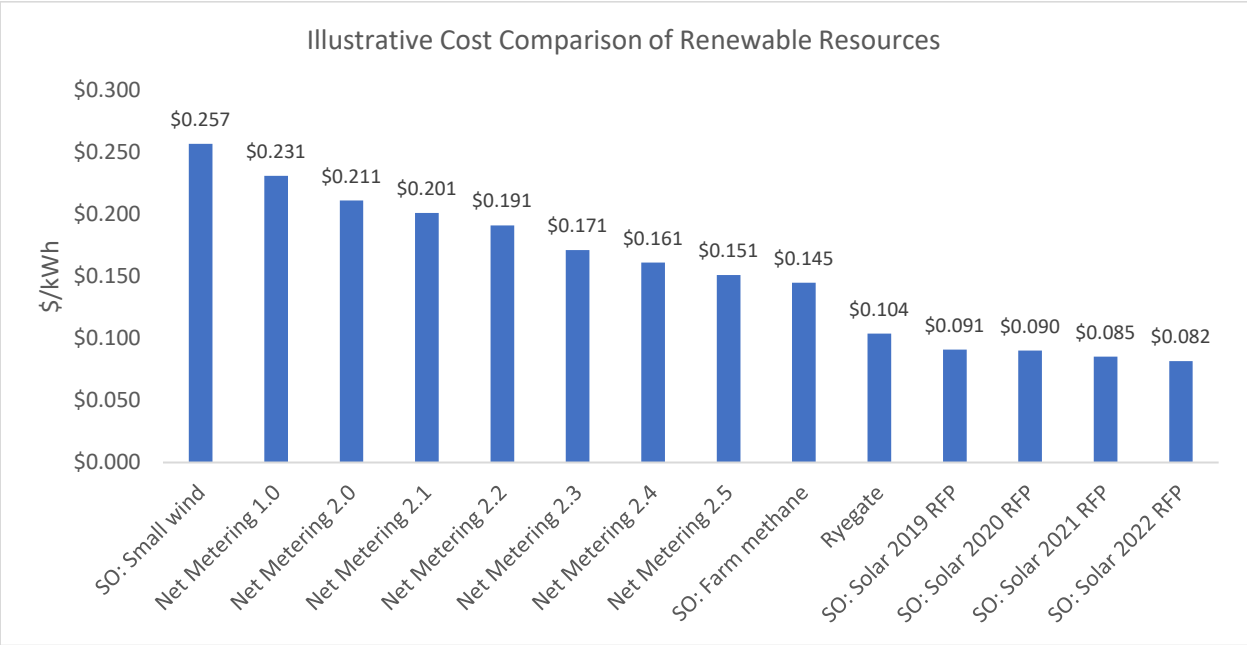

Figure 51: Cost comparison of renewable resources

It is important to note that while the costs of these resources vary greatly, so does the value of the products delivered. For example, the shape of generation from a solar net-metering project is very seasonal and much different than the shape of the generation from a farm methane generator that has a high capacity factor (a measure of actual output relative to capability) across all hours of the day throughout the year. It follows that the value of the generation is also different, as a farm methane project is more likely to be generating at the time of monthly peaks that occur after the sun sets. The solar Standard Offer prices have the most comparable

[104] Utilities have also recently entered into purchase power agreements with developers for the output from solar projects, ranging from $0.085-$0.095/kWh.

value to net-metering but come at a much lower cost, making it clear that even with reduced compensation rates that went into effect September 1, 2022, as a result of the Biennial Review, net-metering still does not satisfy the least-cost planning requirements of 30 V.S.A. § 218c.

Economic Development

While net-metering is one of the most expensive resources available to meet Vermont's renewable energy goals, it does employ many Vermonters. According to the 2022 Vermont Clean Energy Industry Report prepared by the Clean Energy Development Fund,[105] the number of Vermont jobs associated with renewable energy overall at the end of 2021 was expected to be 5,656, with 1,750 of these jobs in the solar industry. This was nearly a 3% increase in solar jobs over 2021 but remained significantly lower than solar jobs in 2017 timeframe. That said, renewable energy workers that spend 100% of their time on renewable energy have increased substantially – from 58% in 2016 to 67% in 2022.

As the solar industry matures, it was reasonable to expect some consolidation of employment in the industry. When incentives were extremely attractive, many new entrepreneurs tried their hand in the solar industry. As subsidies tightened, the most competent solar firms continued to thrive, while less organized and efficient firms may have pursued other ventures. At the same time, the pace of net metering continued to be strong. Vermont has remained first in clean energy jobs per capita, at 6% of the workforce. These are meaningful jobs that contribute to the Vermont economy.

Net metering – with smaller facility sizes than Standard Offer and utility contracted solar projects – creates some marginal construction induced economic development impact. However, it should be acknowledged that under the existing framework of net-metering incentives, these jobs come at a net cost, especially compared to those alternative resources available to meet Tier II of the RES. **Vermont ratepayers are effectively paying a premium to retain jobs associated with net-metering.** While subsidies are ubiquitous in many job sectors, it is useful to recognize the extent of the subsidy in order to make an informed policy decision. The existing framework for net-metering provides jobs but does so in a way that results in economic distortion. To the extent that electric rates are higher than they could otherwise be, there is less disposable income and therefore less economic activity across the Vermont economy.

Meanwhile, keeping electric rates low is essential to encourage electrification – and therefore decarbonization. In Vermont's carbon-intensive heating and transportation sectors, current net-metering compensation creating unnecessary rate pressure inhibits progress toward Vermont's greenhouse gas goals. To meet these goals, Vermont will need more people working in weatherization, electric vehicles, heat pumps, and advanced wood heating systems. Decreasing

[105] 2022 VERMONT CLEAN ENERGY INDUSTRY REPORT, *available at*: https://publicservice.vermont.gov/sites/dps/files/documents/Renewable_Energy/CEDF/Reports/2022_VCEIR_Final_Report.pdf

compensation for net-metering need not lead to job losses in the renewable energy sector if a concerted effort to redirect efforts and incentives toward these sectors is undertaken.

The Department did not undertake an econometric analysis to specifically analyze net-metering economic impacts versus the economic impact of less expensive alternative solar resources. The discussion throughout this report emphasizes the relative costs to ratepayers of procuring net-metering to meet Tier II RES requirements vs. Lower-cost resources such as Standard Offer and utility bilateral contracts. Net-metering is the most expensive pathway to procuring RECs to meet the RES (and energy and capacity to meet other ratepayer needs). It is not necessary to know precisely *how many more* jobs net-metering supports vs. Standard Offer, bilateral contracts, or a new procurement program(s) Vermont could implement. In the bigger picture, the more important questions are related to whether Vermont policy directs limited public dollars efficiently, to the resources and technologies that best reduce costs for Vermonters and ratepayers while mitigating the most greenhouse gas emissions.

Environmental Impacts of Net-Metering

Net-metering, like other distributed renewable generation resources eligible under Tier II of Vermont's Renewable Energy Standard (RES), reduces greenhouse gas emissions and air pollution when it displaces fossil fuel alternatives. A range of variables can affect a specific project's net emission reductions, including the project's generation capacity and lifespan and – when looking at the project from a life-cycle perspective – the amount of embodied emissions associated with the manufacturing of project components, transportation, site preparation and construction activities, and for ground-mounted projects, the extent of soil disturbance and forest clearing. These environmental benefits and costs accrue to society in general.

The Agency of Natural Resources ("ANR") may assess lifecycle (or "embodied") emissions when it evaluates particular projects during Section 248 siting proceedings before the Public Utility Commission. Otherwise, for reporting purposes, ANR calculates year-end emissions based on the overall state power supply for its emissions reporting.[106] The Department's approach to analyzing emissions reductions is to calculate the "but-for" emissions reductions attributable to specific programs. When Vermont adopted the RES in 2015, it articulated statutory requirements for renewable energy supply from resources of various sizes, types, vintages, and locations. The "distributed generation" tier of the RES (also called "Tier II") can be met with a variety of project types, as long as they are less than 5 MW, built after June 1, 2015, and connected to the Vermont grid. Net-metering, Standard Offer, utility-owned, or utility-contracted project are all eligible. Compliance is demonstrated with Renewable Energy Credits ("RECs") and under this framework, a net-metering solar system, for example, will contribute to portfolio renewability and commensurate emission reductions like any other distributed solar resource in Vermont.

[106] https://dec.vermont.gov/air-quality/climate-change

Using 2016, the last year before RES was implemented, as the baseline, the Department calculated what Vermont's emissions would have been based on the electric mix in 2016, which included 35% renewables and 12.8% nuclear (47.8% carbon free). To evaluate 2021 impacts, the Department then calculated what the emissions would have been with 2016 emissions factors applied to the 2021 retail sales. As a result of RES, the electric mix is much different now, with 71% renewables and 16% nuclear. The Department attributes the 36.5% increase in renewables directly to the RES; in 2021 that corresponded to around 690,532 tons of carbon. Because utilities were required to meet a 2021 Tier II obligation of 3.4% of sales (a carveout of a broader "Tier I" obligation of 59% of sales), and net-metering comprised about 66% of Tier II in 2021, the approximate amount of emissions reductions that can generally be attributed to net-metering in 2021 is approximately 18,465 tons of carbon.[107] That said, in the context of the RES, net-metering in effect displaces other solar generation that could have achieved those same greenhouse gas emissions at lower cost. These greenhouse gas emissions reductions may be more rightfully attributed to the RES rather than net-metering.

Tier II-eligible resources such as net-metering are "behind the meter" to the regional system operator, ISO-NE: they look like a reduction in load, similar to energy efficiency, and reduce the energy products utilities need to procure from the regional markets. Any utility purchases that do not include environmental attributes, or RECs for renewable resources, are known as "system mix," and are assigned the emissions characteristics associated with that mix. Below, Figure 3[108] from ISO-NE shows the proportion of regional electric energy generation by resource type:

[107] Statewide, utilities overcomplied in 2021 with Tier I requirements, retiring RECs equal to 71.46% of sales. Net-metering RECs comprised 2.67% of total REC retirements and equivalent GHG emissions reductions

[108] ISO-NE, communication of 12/15/22

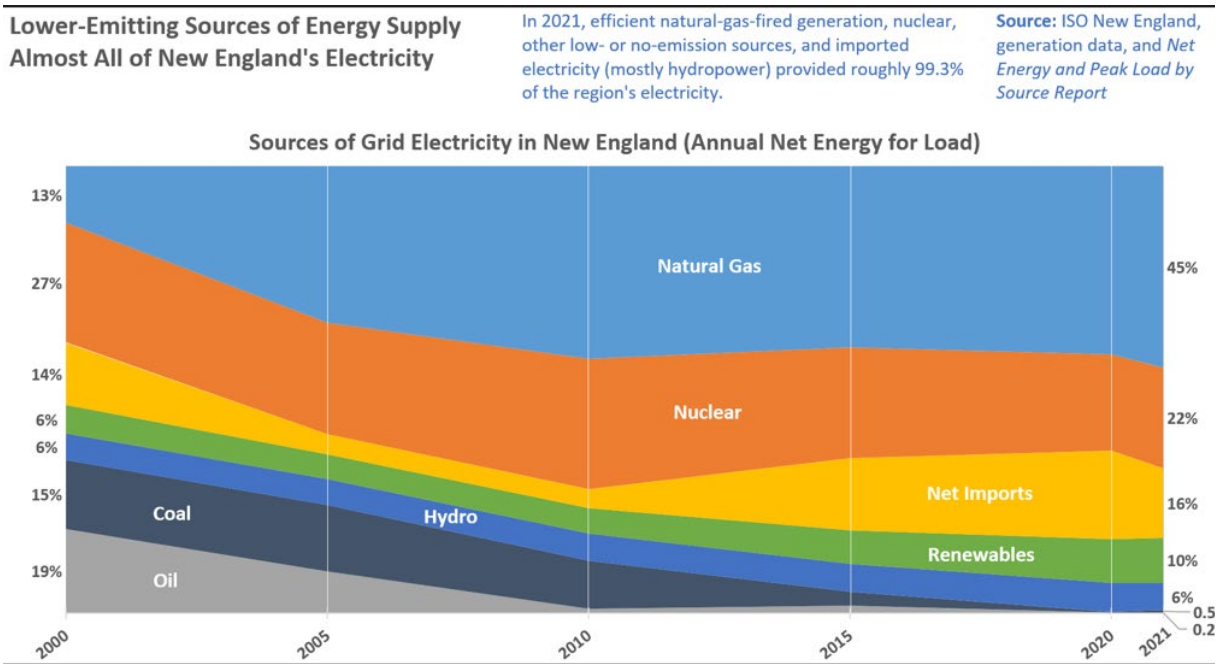

Figure 52: ISO-NE Electric Energy Generation

One takeaway from the chart is that accelerating clean and renewable energy requirements by New England states have led, at least in part, to nearly all the coal plants retiring and the oil plants that remain operate as capacity resources that generate limited energy; the proportion of market-facing renewables is growing, but load (real-time demand not being met with output from small renewables like net-metering, as well as efficiency) is still largely met with natural gas and nuclear generation at present. The system mix corresponds to the following changing emissions profile for the New England region, with decreases in air pollutants corresponding to fossil plant retirements as shown in Figure 4.[109]

[109] https://www.iso-ne.com/static-assets/documents/2022/05/2020_air_emissions_report.pdf

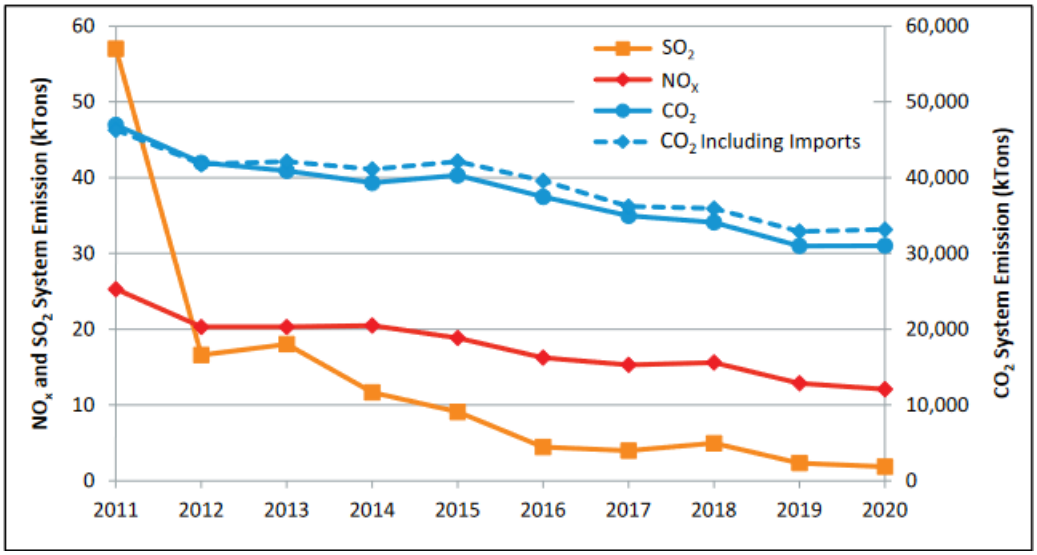

Figure 53: Historical ISO-NE Generators Air Emissions

As discussed above, in order to meet Vermont's RES requirements, utilities will need approximately 28 -57 MW per year of distributed, Tier II-eligible renewable resources to be deployed. A MW of solar, for instance, generated by any one of these resource types contributes equally to meeting the RES requirements (though at widely varying costs to ratepayers, net-metering resources being the most expensive). Similarly, a MWh of solar from any of these resource types contributes equally to offsetting other energy purchases with a particular emissions profile in a particular day or hour. And while the Department evaluates the emissions impacts of the RES on a net annual basis, it's important to recognize that actual emissions from regional generation can vary widely depending on the day or hour, with the regional system emitting the most in the coldest days of winter (when solar, regardless of resource type, is not much help). ISO-NE demonstrates this in the Figure 5[110] below:

[110] https://www.iso-ne.com/about/key-stats/resource-mix/

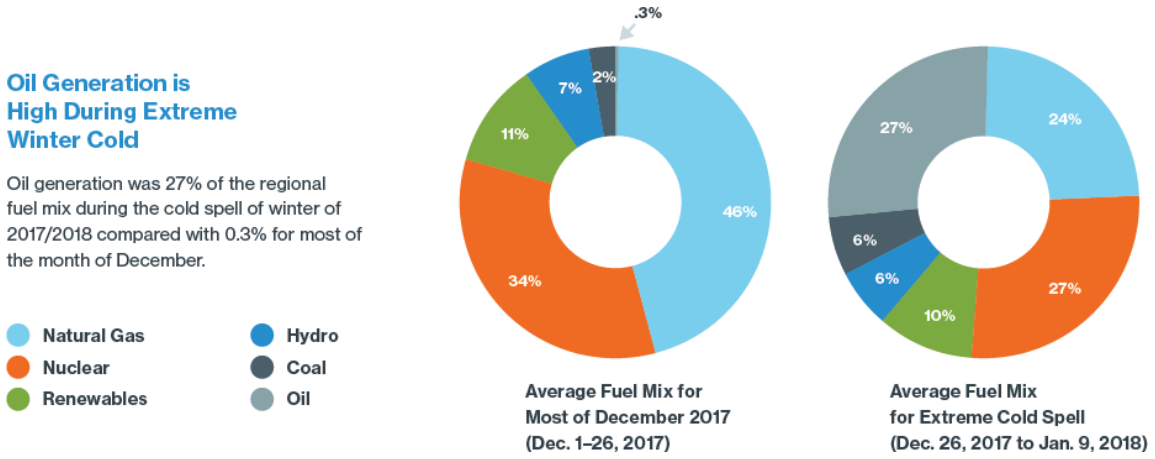

Figure 54: ISO-NE Fuel Mix During Normal and Extreme Winter Events

The Department has articulated concerns with the ability of net-metering customers to export most of their production in sunnier months, to monetize that excess, and to apply it to their bills in darker months elsewhere in this report and in Public Utility Commission Case No. 19-0855-INV, the net-metering rulemaking. This convention is beneficial to individual customers but adds stress to the grid and costs to other ratepayers, especially as distributed solar penetration increases. Like net-metering, the RES allows utilities to "net" their electricity sales with RECs that may be disconnected from real-time load. Some jurisdictions – notably Massachusetts – are taking the first steps toward attempting to incentivize renewable production when (if not necessarily where) it's needed with the adoption of a Clean Peak Standard. The Clean Peak Standard assigns higher value to generation correlated with peak load hours. This change to their Renewable Portfolio Standard is still quite new, and the Department looks forward to understanding its successes and challenges as it unfolds.[111]

In addition to environmental benefits from emissions reductions, net-metering – again like other distributed renewable generation resources eligible under Tier II of Vermont's RES) – is not without environmental costs. Construction of net-metering systems, like any construction project that uses fuel-burning equipment or generates dust, creates temporary air emissions. Also, all forms of energy development in Vermont have a footprint on the landscape. In some cases that footprint is on rooftops, parking lots, landfills, or other already developed sites; in other instances that footprint is on an undeveloped landscape or "greenfield" site. Conversion of land from natural conditions, as can happen with net-metering systems on greenfields, can result in loss of or damage to natural landscapes and ecological function. These natural landscapes provide numerous environmental benefits to Vermonters, including clean air and water, crop pollination, carbon sequestration, flood protection, and fish and wildlife habitat.

[111] https://www.mass.gov/info-details/clean-peak-energy-standard-guidelines. Critiques regarding the emissions benefits of the MA Clean Peak Standard structure are starting to emerge, indicating further refinement of the concept or pursuit of alternatives may be warranted. See, for example, https://www.sciencedirect.com/science/article/abs/pii/S0360544221003649?via%3Dihub.

The Public Utility Commission's Net-Metering Rule (Rule 5.100) incents, and in certain cases requires, the siting of net-metering systems on one of 9 types of "preferred sites." One goal of the preferred site framework is to promote siting of net-metering systems on the already developed landscape. It is not clear, based on the analysis conducted by ANR for this report, that that goal was achieved. From 1/8/21 through 12/2/22, ANR comprehensively reviewed 83[112] net metered applications that broke out in the following preferred site categories, based on ePUC summary information:

- Not a preferred site – 3
- Sanitary landfill – 2
- Parking lot canopy – 2
- Previously developed site – 3
- Gravel pit, quarry, etc. – 3
- Brownfield – 4
- Near customer load – 27
- Designated in municipal plan or letter – 39

Only 14 of the 83 applications were in preferred site categories that generally involve the already-developed landscape (sanitary landfill, parking lot canopy, previously developed site, gravel pit, brownfield). As with past reporting periods, the majority of applications were Designated in municipal plan or letter preferred sites. Though a similarly high number of projects were located near customer load.

Development of net-metering systems at gravel pits, quarries, landfills, and brownfields can hasten their reclamation, facilitate environmental investigation and remediation activities, and inject income to offset maintenance and site management costs, which are all beneficial outcomes. Though significant, development at these sites represents only 17 percent of all net-metering applications that were comprehensively reviewed by ANR during this biannual period. There have been no applications for net-metering systems for the Superfund preferred site type.

Of the 83 net-metering applications this biannual period that required comprehensive review by ANR, 37 involved some measurable level of forest clearing resulting in approximately 78 acres of forest conversion.[113] Of those, 21 applications involved an acre or more of forest clearing – the vast majority of which in the Designated in municipal plan or letter preferred site category. Incentivizing as preferred sites the conversion of forests for net-metering when non-forested alternative sites are available, unnecessarily displaces the carbon sequestration benefits provided by forests.

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[112] All applications put on ANR's Section 248 Agenda for Agency-wide review between 1/8/21 and 12/2/22. This may not align exactly with when an application is filed with the PUC. ANR generally does not review net-metering registrations and reviews applications for net-metering systems under 50 kW on a case-by-case basis.

[113] Acres of forest cleared estimated by Fish and Wildlife Department from initial application filing or, if the Department did not estimate, taken from applicant testimony.

Net-Metering and the Grid

Infrastructure Impact of Net Metering

Under the best-case scenario, net-metered and other distributed energy resources ("DERs") can minimize infrastructure needed to support the grid or import energy from more distant locations, and reduce line losses associated with such imports.[114] Those are some of the reasons why the Vermont System Planning Committee ("VSPC") evaluates distributed generation – alongside energy efficiency and load management – as an alternative to poles-and-wires solutions when it assesses potential solutions to grid reliability concerns. In the past, many of these concerns were driven by load growth. And while energy efficiency, net metering, and the decoupling of economic growth from electric demand growth has effectively flattened overall load growth in Vermont in recent years and in the near-term future, the challenge of strategically deploying behind-the-meter resources in time and space to match specific areas or times of higher loads grows. Since nearly all the net-metering in Vermont is "uncontrolled" solar – in that it's not time-shifted with storage to match demand – its output coincides with the daily and seasonal arc of the sun. Customer demand for energy in the dark of night and of winter is therefore not being served with solar resources, which has reduced its infrastructure deferral benefits.

[114] In Case No. 19-0855-RULE, the Department included a line loss value of 8%, consistent with the Avoided Energy Supply Costs (AESC) study and further explored by the Commission in Case No. 19-0397-PET. The value was updated to 9% in the most recent AESC (see Case No. 21-2436-PET). The line losses calculated in that proceeding were specific to energy efficiency. The Department expects that transmission losses would be similar for net-metering resources as they are considered behind-the-meter resources from a regional perspective.
It is doubtful that the value for distribution losses assumed in 19-0397 and 21-2436 would be appropriate, however. For energy efficiency, there is no excess generation exported to the grid, as there is under the net-metering structure. This generation in itself can result in losses, particularly in constrained areas with significant amounts of generation on the distribution system. Distribution loss impacts of generation facilities are case specific and cannot be considered on a statewide basis.

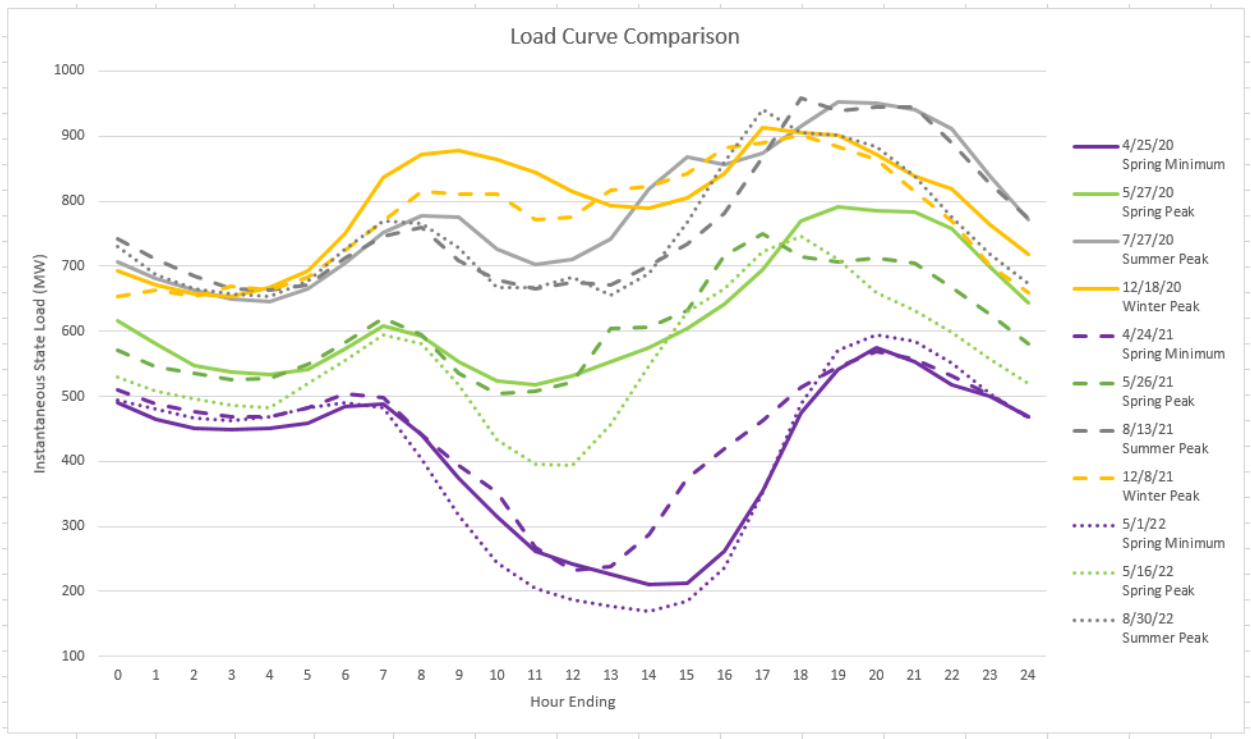

Figure 55: Sample of Vermont load shapes throughout the year, over the last three years [115]

In fact, it's increasingly clear that that net-metering will necessitate – rather than reduce – the need for additional electric infrastructure. This dynamic is directly related to the large amount of solar net-metering (317 MW) and other distributed solar (another 147 MW) in Vermont compared to daytime gross load (which can reach as low as about 650 MW), particularly on a localized basis, where solar penetration can be so high that at times, generation exceeds load at the distribution transformer. When that happens, a number of reliability issues and potential costs can arise. According to IEEE,

> *One of the more frequent issues utilities will have to address is the potential for a large amount of substation transformer backfeed stemming from reverse power flow on distribution circuits. Excess PV output on the distribution system during periods of minimum daytime loading causes a number of issues for utility planning and operation, such as temporary overvoltage conditions, the need for protection schemes modifications, and equipment failure from an increase in voltage regulation operations.*[116]

[115] Source: VELCO

[116] https://ieeexplore.ieee.org/document/8274081

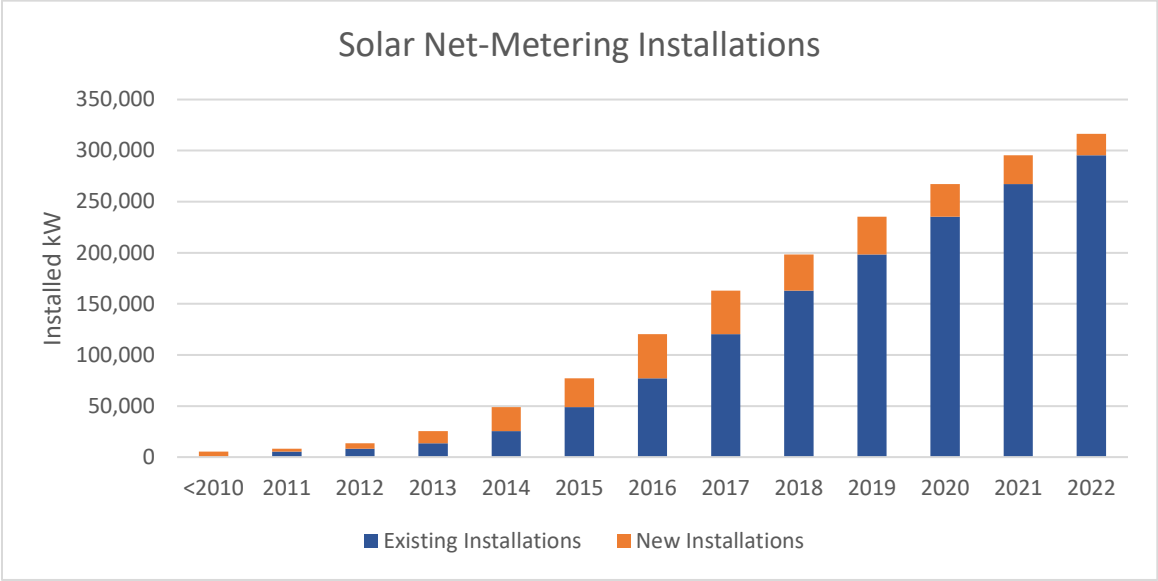

Figure 56: Vermont Solar Net-Metering Installations by Year [117]

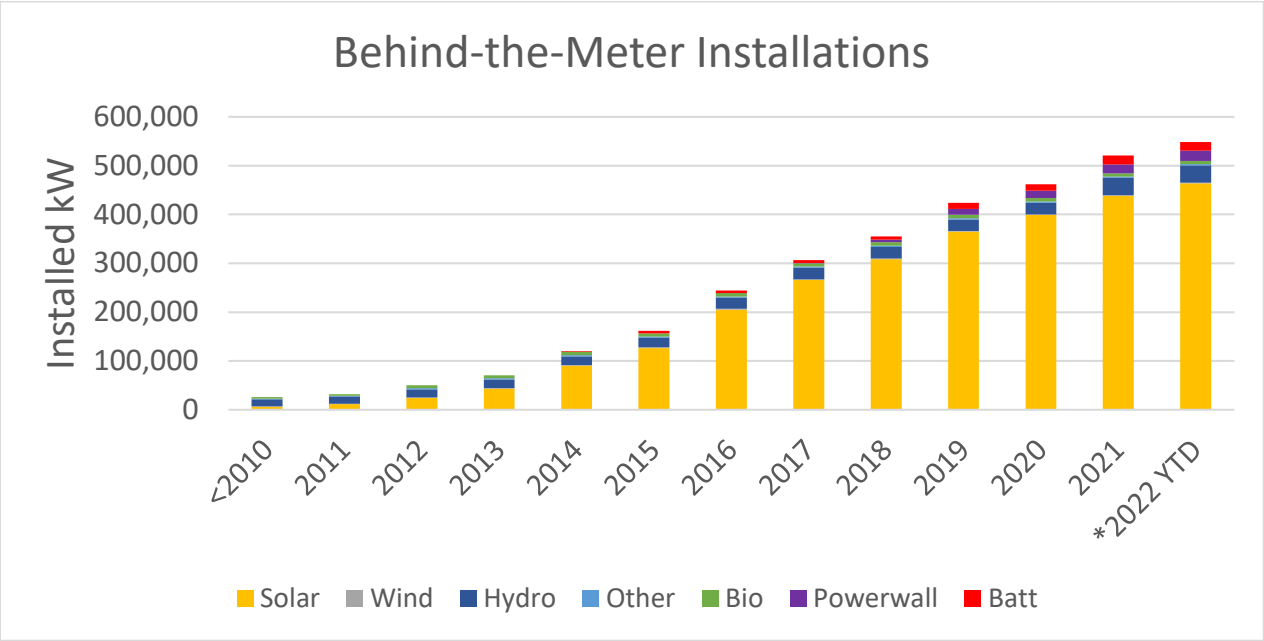

Figure 57: Vermont Behind-the-Meter Installations by Technology [118]

The blanket solution that could address so-called overgeneration is to upsize substation transformers – to the tune of several million dollars apiece. Historically, regulatory policy calls for assigning costs to cost causers. However, this becomes challenging in the case of net-metering, where the impact on the system is created by the cumulative effect of tens or hundreds

[117] Derived from utility monthly DG resource surveys to ISO-NE through October 2022
[118] Ibid.

of existing net-metering generators that slowly utilize the remaining headroom on a substation transformer. New approaches of distributing costs to interconnected DERs are emerging.[119]

In Green Mountain Power ("GMP") territory, for example, at least 22 of 164 substations are approaching or already at substation capacity. For at least one type of upgrade – Transmission Ground Fault Overvoltage or "TGFOV" – the Public Utility Commission has approved a methodology for addressing a potential grid liability by allowing GMP to collect an additional fee from interconnecting net-metering resources that goes into a fund used to pay for mitigating upgrades.[120] The map below shows circuits in GMP service territory, color-coded according to "room" on the substation transformer for additional generation. Projects proposed in areas outlined in gray are subject to the TGFOV fee; and the key explains limitations in other shaded areas (e.g., red circuits connect to the most highly generation-constrained substations).[121]

[119] https://www.nrel.gov/dgic/interconnection-insights-2018-08-31.html

[120] See Case No. 19-0441-TF

[121] GMP Solar Map, available at https://www.arcgis.com/apps/webappviewer/index.html?id=4eaec2b58c4c4820b24c408a95ee8956, accessed 12/14/20. Burlington Electric Department has a similar map available here: http://burlingtonvt.maps.arcgis.com/apps/Embed/index.html?webmap=bb1b9156d8294e308ecfe803131e8c00&extent=-73.2731,44.4574,-73.1094,44.5091&zoom=true&scale=true&legend=true&disable_scroll=false. And VEC's is here: https://www.arcgis.com/apps/mapviewer/index.html?webmap=3d526efbc62b4ab78aa5d2b56b3b8fef.

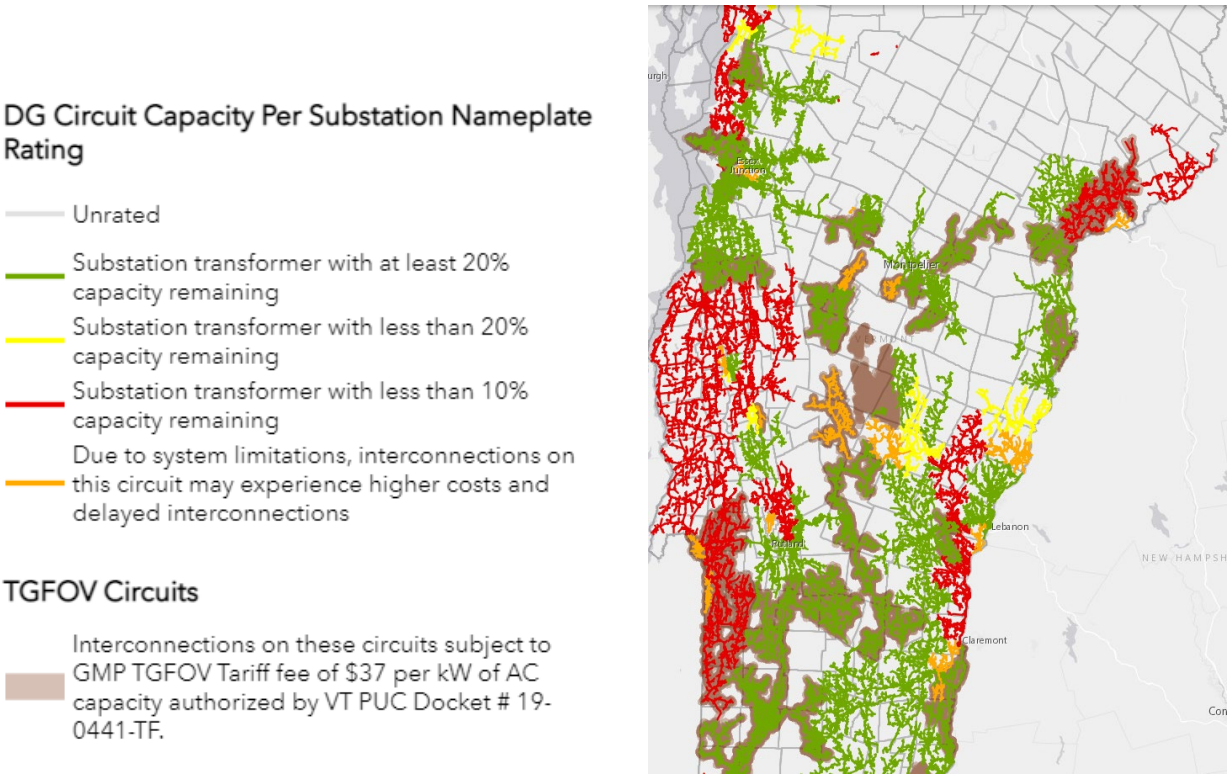

Figure 58: Green Mountain Power DG Circuit Capacity

One of the main challenges for Vermont policymakers, regulators, and utilities to address as net-metering (and other renewables programs) evolve is how to address such generation-constrained areas in the myriad renewables policies, programs, regulations, and tariffs, from net-metering to transmission planning and interconnection requirements. The TGFOV tariff is one example; another is the impact fee that larger-scale net-metering resources interconnecting in the so-called Sheffield Highgate Export Interface ("SHEI") area of Vermont's transmission system currently pay.[122] This area of northern Vermont has roughly ten times more generation than load, resulting in curtailment of generation – including ratepayer-funded generation – about 20% of the time (and every additional renewable generation source interconnected exacerbates the curtailment).[123] Because distributed renewable energy has also boomed in other New England states – with whom we share a transmission grid (and related expenses) to transport wholesale generation across the region – these questions are starting to matter to the region's transmission grid planner and operator, ISO-NE, too.

As solar penetration has increased across the region, resulting load patterns reflect the "bite" behind-the-meter solar has taken out of midday electricity demand – meaning once the sun sets, demand that had been served (and "masked") by distributed solar suddenly "reappears" to grid

[122] See Case No. 20-3304-PET. The fee for recent projects has been ~$75/kW and is calculated to make ratepayers whole for utility-owned generation curtailments based on present generation, load, and transmission conditions in the SHEI.
[123] https://www.vermontspc.com/grid-planning/shei-info.

operators and must be served by other types of resources. This phenomenon, first observed in California, is commonly known as the "duck curve."[124] In the screen capture of ISO-NE's dashboard below (taken 12/21/22), the curve is apparent.

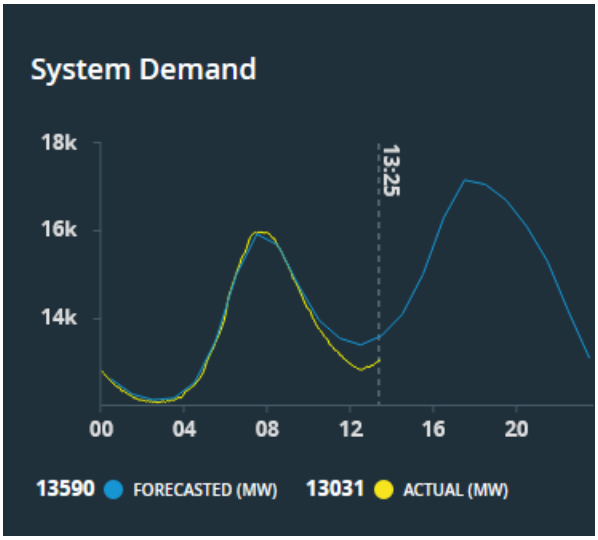

Figure 59: ISO-NE Energy Dashboard [125]

A decade or so ago, distributed solar had just started eating into mid-day peak demand in the region. ISO-NE recently analyzed solar penetration and demand from 2012 to 2015, in order to estimate demand reductions from each increment of solar installed going forward. Figure 11 shows estimated peak reductions per MW of installed solar and demonstrates the diminishing returns as penetration increases. (This assumes no change in the demand profile of load or the generation profile of solar – both of which are, however, becoming increasingly likely as flexible load and energy storage technologies rapidly evolve and come down in cost.)

[124] https://www.nrel.gov/news/program/2018/10-years-duck-curve.html
[125] https://www.iso-ne.com/ (retrieved 12/21/22 at 1:31 p.m.)

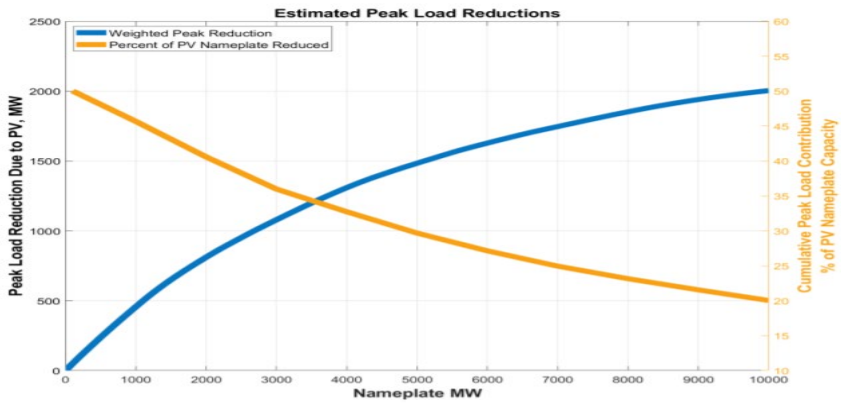

Figure 60: ISO-NE Peak Load Reductions Due to Solar [126]

ISO-NE has spent considerable time conducting its Transmission Planning for the Clean Energy Transition (TPCET) initiative in recognition of the growing penetration of distributed solar and other DERs and the commensurate complexities in planning a reliable transmission system around potentially millions of resources it cannot see or control.[127] ISO-NE anticipates incorporating additional study conditions beyond peak demand, including the intersection of high/low demand with high/low solar production, as it begins to observe extremely low midday net loads. Additionally, ISO-NE is evaluating tradeoffs between flexibility and reliability, including risks of fleets of DERs tripping offline in response to transmission faults, and other novel conditions related to high penetrations of inverter-based resources, including grid stability and inertia. ISO-NE is also commencing a second phase to this effort, Economic Planning for the Clean Energy Transition, which will address such topics as the input assumptions and capabilities of tools used for economic analyses and will perform a dry-run of new economic study process improvements.[128] In its upcoming study of the Vermont system (called a Needs Assessment), ISO-NE will evaluate the transmission reliability impacts of high amounts of distributed renewable generation production that coincides with low load levels, incorporating those lessons learned and methodologies derived from the TPCET.

To enable growing penetrations of distributed generation in Vermont, the Department and others are examining more precise, less expensive ways to address the issue of overgeneration than upsizing substation transformers. These all focus on better orchestration of generation and load and range from directing generation toward or away from particular locations to time-shifting generation or load with storage, to maximizing the abilities of "smart inverters" to curtail excess generation. The key to many of these solutions is implementation of rate signals that direct the

[126] See https://www.iso-ne.com/static-assets/documents/2020/03/3_peak_load_reductions_update.pdf
[127] https://www.iso-ne.com/static-assets/documents/2022/05/a10_tpcet_follow_up_and_roadmap_for_future_needs_assessments.pdf
[128] https://www.iso-ne.com/static-assets/documents/2022/08/a7_epcet_pilot_study_new_modeling_features_and_initial_benchmark_scenario_results.pdf

owner of a DER, including a flexible load resource, to alter its behavior in response to a price signal associated with a grid requirement. A complementary tool is direct control of DERs by a utility (or third party on behalf of a utility), though given the proliferation of DERs, this is likely going to require investment in real-time situational awareness, monitoring, and control tools, some of which are not yet commercially available. In 2019, the Department undertook a Rate Design Initiative to explore some of these concepts, which culminated in a report recommending strategies to implement rates.[129] An ad-hoc subcommittee of the Vermont System Planning Committee began examining how flexible loads, energy storage, and curtailment can be used – singly or in concert – to enable additional distributed generation on a constrained circuit.[130] This and similar work will be picked up by the emergent Technical Working Group initiated by the Department and housed under the Vermont System Planning Committee.[131] The Department's proposal to reform net-metering compensation to value production consumed on-site higher than production exported beyond the customer meter would also have the effect of mitigating overgeneration and related infrastructure costs.[132]

Benefits of Connecting to Distribution System

Net metering, as defined in statute, only works when the customer is connected to and benefiting from their electric utility's distribution system:

> ***30 V.S.A. 8002(15):*** *"Net metering" means measuring the difference between the electricity supplied to a customer and the electricity fed back by the customer's net metering system during the customer's billing period.*

As electric customers are generally subject to a monthly billing period, the "netting" generally takes place over a month. Under the current net-metering rule,[133] small systems located at customer premises generally serve load in real time (i.e., "spin the meter backward), and either send "excess" kilowatt-hours ("kWh") back into the grid or pull additional electricity from the grid to serve demand that is higher than (or needed at a different time than) production. Customer electric meters can measure both of these flows and at the end of the month utility billing departments net excess kWh with utility-delivered kWh. If there are net kWh delivered, they are billed at the residential or other applicable rate. If there are excess kWh generated, those are credited to the customer at the applicable base rate (for most customers, this will be a blend of the statewide residential rates).

Separately, "gross" kWh produced by the net-metering system – measured by a separate production meter – are multiplied by applicable adjustors, which can either be positive or negative depending on the system's size and siting. The resulting credit (or debit) is also applied

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[129] https://publicservice.vermont.gov/content/rate-design-initiative

[130] https://www.vermontspc.com/vspc-at-work/subcommittees

[131] https://www.vermontspc.com/library/document/download/7631/22%20Oct%2026%20VSPCagenda_cleaned.pdf

[132] See Case No. 19-0855-RULE, 11/1/19 *Department of Public Service Report on Public Utility Commission Net-Metering Information Requests*

[133] Net-Metering Rule Effective 07-01-2017 - 5100-PUC-nm-effective-07-01-2017_0.pdf

on customer bills. Credits cannot be used toward "fixed charges" such as the customer charge,[134] but they can roll over for a 12-month period, which enables customers to carry over excess production from summer to winter months *on paper*. For group net-metering systems – often larger, 150 kW or 500 kW – more often than not, all production is considered to be excess and is generally applied as a credit to all subscribers of the system, who can be located anywhere in a utility service territory.

In addition to relying entirely on the distribution system for the mechanics of net-metering, net-metering customers are also reliant on the distribution system to serve load that their net-metering systems are unable to meet: in real time, throughout the day, at night, and over the course of the year. If a customer wanted to rely entirely upon their own distributed generation, they would need to add battery storage and size their overall system to meet their power needs throughout the year. Utilities are obliged to serve their customers, safely and reliably, and must ensure they have resources to meet and serve customer demand regardless of the existence and behavior of that customer's net-metering system.

Group systems generally send all of their production directly to the distribution grid. None of it is offsetting on-site load, and utilities therefore treat it all as "excess," allocating monetary credits to subscribers based on total production multiplied by the applicable base rate and by the applicable adjustors. Customers of these systems are entirely dependent on the grid and utility to supply their electricity demand. Without the net-metering construct, these customers would not be able to associate the virtual net-metering system with their home or business accounts.

Net-metering customers in Vermont participate in the program for a variety of reasons, from reducing their electric bill to participating in the state's renewable expansion and decarbonization. Because the state's electricity mix is highly renewable overall (71%, and 100% in some utility territories), and the greatest opportunity reduce emissions is in the transportation and heating sectors (including by electrification), it may be more impactful at this point in time for customers to instead invest in electric vehicles and heat pumps – and for policymakers to work to limit the rate impacts from net-metering in order to encourage use of electricity for these purposes.

Costs and Benefits of Reliability and Supply Diversification

Electric grid reliability is governed by specific requirements and standards, at both the bulk and distribution system levels – and net-metering systems have potential impacts, both positive and negative, on both. The primary reliability authority is the Federal Energy Regulatory Commission ("FERC"): "All users, owners and operators of the bulk power system must comply with the mandatory Reliability Standards developed by the electric reliability organization and approved by FERC."[135] ISO-NE, Vermont Electric Power Corporation (VELCO, Vermont's

[134] Systems installed under pre-2017 rules were allowed to apply credits toward fixed charges and continue to be able to do so for ten years from their commissioning date, at which point they revert to net-metering tariffs in place at that time.

[135] https://www.ferc.gov/sites/default/files/2020-04/reliability-primer_1.pdf, p. 39.

transmission system operator), and others subject to this definition must comply with reliability standards set by the North American Electric Reliability Corporation ("NERC"),[136] and the Northeast Power Coordinating Council ("NPCC").[137] Distribution utilities are further subject to regulation by the Vermont Public Utility Commission and are required to file Service Quality and Reliability Plans, with reporting on metrics such as the frequency and duration of outages.

At each of these levels, distributed energy resources such as net-metered solar are bubbling up as an area for greater attention and focus. For instance, see NPCC's *DER Guidance Document, Distributed Energy Resource (DER) Considerations to Optimize and Enhance System Resilience and Reliability*.[138] These two concepts – resilience and reliability – are often used interchangeably, but the Department believes careful usage and definition of each term is essential to ensuring that stakeholders discussing impacts of a resource such as net-metering on reliability, or resiliency, are not talking past each other. Reliability is a core tenet of Vermont energy policy:

> *30 V.S.A. § 202a: It is the general policy of the State of Vermont:*
>
> *(1) To assure, to the greatest extent practicable, that Vermont can meet its energy service needs in a manner that is adequate**, reliable**, secure, and sustainable; that assures affordability and encourages the State's economic vitality, the efficient use of energy resources, and cost-effective demand-side management; and that is environmentally sound.*

It is also a core tenet of the concept of "energy assurance," as articulated in Vermont's Energy Assurance Plan (itself part of the state's Emergency Operations Plan) where energy assurance is defined as:

> "*The ability to obtain, on an acceptably **reliable** basis, in an economically viable manner, without significant impacts due to Energy Supply Disruption Event(s), or the potential for such events, sufficient supplies of the energy inputs necessary to satisfy Residential, Commercial, Governmental, and non-governmental requirements for Transportation, Heating (space and process heat), and Electrical Generation."*[139]

In other words, reliability is a strictly defined term subject to specific standards (e.g., SAIDI, CAIDI, SAIFI), metrics, reporting, enforcement, and penalties. It is, foundationally, about avoiding "loss of load," or power outages, both in number and duration, during day-to-day operations, with metrics focusing on reliability performance over a specified period of time. NERC defines a reliable bulk power system as, "one that is able to meet the electricity needs of end-use customers even when unexpected equipment

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[136] https://www.ferc.gov/industries-data/electric/industry-activities/nerc-standards

[137] https://www.npcc.org/program-areas/standards-and-criteria/regional-standards

[138] https://www.npcc.org/content/docs/public/program-areas/standards-and-criteria/der-forum/2020/der-v2-11-20-2020.pdf

[139] https://publicservice.vermont.gov/sites/dps/files/documents/VT%20Energy%20Assurance%20Plan%20August%202013.pdf

failures or other factors reduce the amount of available electricity."[140] The concept includes both *resource adequacy* – i.e., sufficient supply – and *security*, or the ability to withstand sudden, unexpected disturbances, either natural or man-made.

Resilience (or resiliency), on the other hand, is more of a term of art, subject to a variety of proposed definitions, with an evolving landscape of potential metrics, but without specific regulatory "teeth."

FERC has proposed the following definition of resilience, which has been adopted by NERC: "The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event."[141] Resilience, unlike reliability, is usually thought of in terms of a specific, low-probability, high-impact event. But without imposition of a measurement or valuation framework, it is not particularly meaningful to describe a grid as resilient, or to describe a resource as providing grid resilience. The U.S. Department of Energy, national labs, academia, and industry organizations are working on various frameworks to value resilience, but none has yet emerged as an industry standard, or been adopted in Vermont as a guiding framework. Ongoing metrics-defining work of the Department, utilities, and Climate Council – described further in Chapter 4 of the 2022 CEP[142] – should help in this regard, with time.

Net-metering, as a financial mechanism for incentivizing development of renewable energy systems by crediting customer bills for the production from those systems, does not have any defined relationship with the concepts of either reliability or resiliency. Small, distributed solar – the predominant type of system being incentivized with the net-metering program – potentially impacts both, in positive as well as negative ways. Distributed solar on its own is not going to keep customers' lights on if the grid goes down, unless additional investments in storage and protections are made in specific areas of the grid to benefit specific customers – such as in the case of those customer-sited battery storage programs or community microgrids.[143] A customer – or group of customers, in the case of a microgrid – with a battery storage system may be able to continue to power specific loads for 1-2 days, longer if their "island" includes a solar system. In that sense, many net-metered systems can be considered to be a *precursor* to enhanced reliability (or, potentially, resiliency).

In terms of individual generation projects, impacts on grid reliability are reviewed through the interconnection process, which is required for a system to obtain a Certificate of Public Good and to interconnect to the grid.[144] A system might be required to install specific protective

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[140] https://www.nerc.com/AboutNERC/Documents/NERC FAQs AUG13.pdf

[141] https://elibrary.ferc.gov/eLibrary/#, Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing
Additional Procedures, 162 FERC ¶ 61,012, para. 14, FERC Dkt. No. AD18-7-000 (Jan. 8, 2018). Pp. 12-13.

[142] https://publicservice.vermont.gov/about-us/plans-and-reports/department-state-plans/2022-plan

[143] In those programs, customers pay for the enhanced personal grid reliability offered by the battery storage, while all the utility's customers both pay for and gain benefit from the other values provided by the storage in the aggregate, such as reducing peak-related charges. https://greenmountainpower.com/rebates-programs/home-energy-storage/; https://vermontelectric.coop/flexible-load

[144] https://Commission.vermont.gov/document/commission-rule-5500-electric-generation-interconnection-procedures

equipment in order to demonstrate it will not adversely impact system stability and reliability – though small, customer-sited net-metered systems are unlikely to trigger such requirements. However, like the aggregated impacts on grid infrastructure discussed earlier, the cumulative impact of many small systems can eventually impact grid reliability in ways that are impossible to associate with any one individual system.

Another way net-metered systems act as a precursor to enhanced grid reliability lies in the inverters tying these systems to the grid. What is currently viewed as a reliability liability from the growing fleet of these resources – the potential for a fault on the grid to trip the fleet offline like so many dominoes, taking a chunk of supply offline all at once – can be mitigated with upgrades to inverter equipment or modification of settings. Most net-metered solar in Vermont is tied to the grid with inverters (converting DC production to AC supply aligned with the grid) that signal the system to trip offline if they sense a grid perturbance. This is a safety function – if the power fails and a net-metered system is still energized, lineworkers coming into contact with the facility could be electrocuted. However, to encourage systems to stay offline in conditions shy of power outages and thus support the system, ISO-NE has issued a so-called "Source Requirements Document" ("SRD"), specifying inverter settings during the interconnection process to ensure inverters ride through grid perturbances.[145] Most – if not all – utilities in Vermont require interconnecting customers to follow the SRD specifications. As advanced inverters enter the marketplace, distributed solar employing these inverters (new systems and replacements for existing systems at the end of inverter life) hold potential to become a newfound source of grid support services, particularly if interconnection standards encourage them to do so.[146]

At the Vermont System Planning Committee October 22, 2022, quarterly meeting, VELCO shared details from a July transmission event where an outage in New York caused grid frequency to rapidly fall and net load to increase in New England.[147] About half of the load increase was in Vermont, and this was likely due to distributed solar PV units tripping offline as a result of sub-optimal inverter settings. Ensuring use of smart inverters compliant with IEEE 1547-2018, full implementation of that standard by distribution utilities, and considering ways to update settings on existing inverters and incent/confirm settings on new or replacement inverters are all important steps to ensuring Vermont's fleet of net-metering resources enhances – and does not degrade – grid reliability and resilience. The Technical Working Group being led by the Department should help advance this conversation.

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145 https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwj68rK0vMTtAhVYVs0KHTd7CxQQFjACegQIBBAC&url=https%3A%2F%2Fwww.iso-ne.com%2Fstatic-assets%2Fdocuments%2F2018%2F02%2Fa2_implementation_of_revised_ieee_standard_1547_presentation.pdf&usg=AOvVaw1XF4tUehcQv9wj9zRgdIRg

146 https://www.energy-storage.news/blogs/the-long-awaited-ieee-standard-that-paves-the-way-for-more-energy-storage-o

147 https://www.vermontspc.com/library/document/download/7632/VSPC_Event_tripping_DG.pdf

Other ways to harness the net-metered solar fleet to enhance grid reliability include coupling systems with on-site or upstream storage to firm production or to store-and-release production to better match loads; encouraging system sizing to match on-site or area load; and implementing real-time grid visibility tools to enable situational awareness by system operators. These actions all require additional investment. It is inconsistent with least-cost planning principles to require ratepayers who already pay nearly twice as much for net-metered solar as they would for other RES-eligible solar to also have to bear costs associated with better integrating this fleet of resources in order to maintain or enhance grid reliability. This is especially true when there are many other reliability investments that could yield greater benefits for the same amount of investment, including the basics such as tree trimming, moving cross-country poles to roadsides, animal protections, looping radial lines, and even undergrounding lines.

In general, having more diversity in type, size, scale, and vintage of resources is generally considered to bolster grid reliability and the robustness of resource portfolios (i.e., avoiding the problem of all the eggs in one basket). Distributed solar has increased these types of diversity in Vermont and the New England region over the last decade, but if solar continues to dominate as a resource type, benefits associated with that particular type of diversity will diminish. Distributed solar reduces Vermont's net loads and the need to purchase energy to serve load, when the solar fleet is producing. However, in the region as a whole, each additional MW is shifting out the peak further into the evening, meaning incremental new solar will deliver energy at times it is not needed, necessitating utilities to resell excess supply at times when regional market prices are low (because everyone is doing the same thing). This issue is heightened in Vermont where utilities have invested through utility-owned generation or long-term contracts in non-solar renewable generation in order to fulfill statutory requirements.

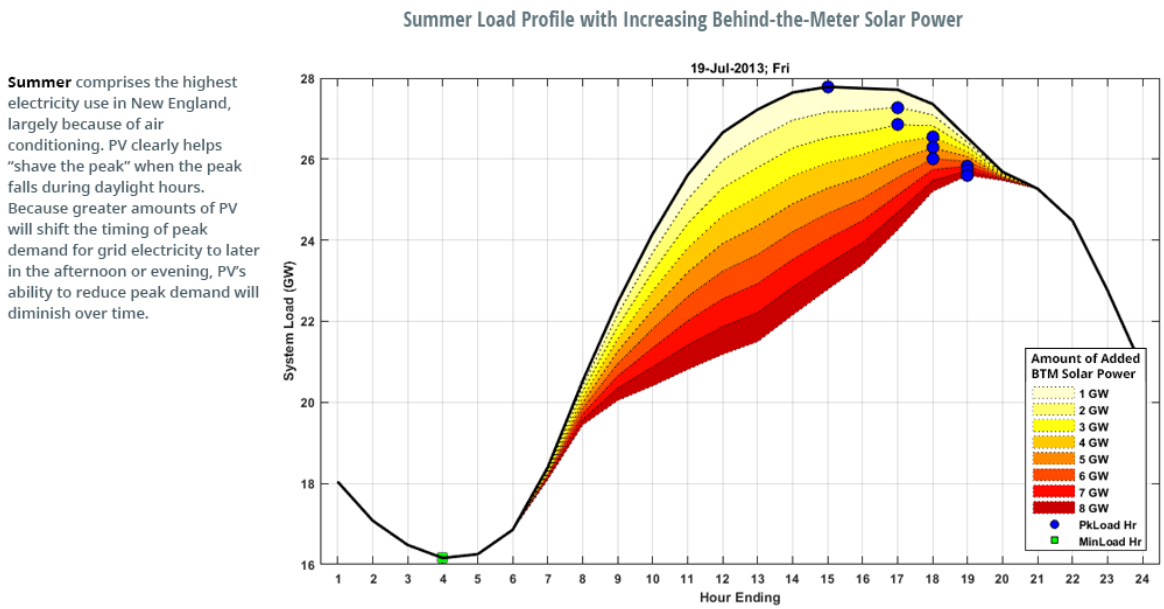

Figure 61: ISO-NE Summer Load Profile with additional behind-the-meter solar [148]

Figure 12 from ISO-NE shows the impact solar has had on net loads visible to the regional system operator, pushing them out into evening – a shape that will be exaggerated with the addition of electric vehicles that want to charge in the evening.

In addition, utilities and system operators need to ensure sufficient resources are online to meet load regardless of the weather. Weather forecasting is becoming an increasingly powerful and accurate tool for assessing next-day and real-time demand in order to ensure sufficient resources are lined up to meet that demand, but long-term, day-to-day and minute-by-minute variability in storms and cloud cover for non-firm solar resources means grid planners and operators may need to discount solar's availability (and thus contribution to meeting load and supplanting other resources). Figure 13 below shows the contribution (and resulting net load shapes) of solar on a cloudy vs. A sunny spring day, and the screen-capture of the regional system in real time just below that, Figure 14, shows the impact of winter storm Gail's snow cover on forecasted demand.

[148] https://www.iso-ne.com/about/what-we-do/in-depth/solar-power-in-new-england-locations-and-impact

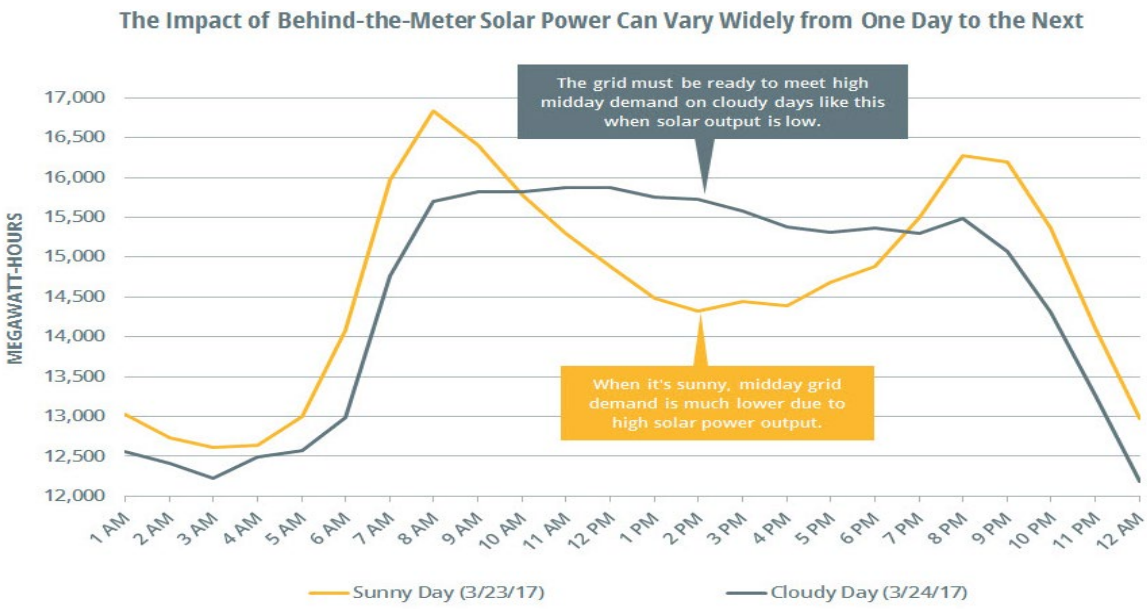

Figure 62: ISO-NE load shape with and without solar [149]

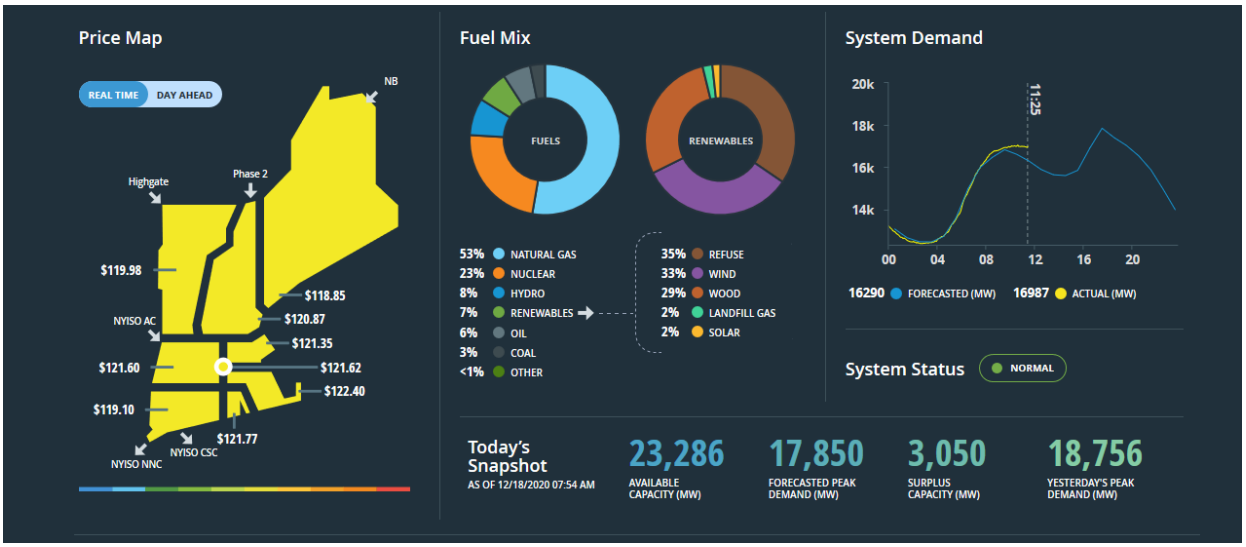

Figure 63: ISO-NE Energy Dashboard [150]

[149] See note 36.

[150] ISO-NE.com, screenshot taken at 11:30 a.m. On 12/18/20, the day after winter storm Gail. Relatively sunny conditions prevailed across the region, which ISO-NE likely took into account when they forecasted solar output decreasing midday-demand. The actual demand remained high, however, leading to increased prices and fossil fuel generation coming online. The Department interprets this chart to indicate many solar installations remained covered in snow, and it's unclear when they would start to again contribute to reducing loads.

While net-metering deployment has diversified resource supply in terms of size, it has been almost entirely composed of solar with uniform generation profiles that are becoming less well aligned with customer, circuit, utility, and regional load profiles as penetration increases.

In other words, distributed solar is becoming one of the single biggest resources in Vermont's portfolio, with an installed capacity at over 45 percent of state peak load (higher when considering average or low load days and months), with even higher penetrations in some areas. Without changes to programmatic frameworks to better align production with loads (and vice versa), the value provided by net-metered solar will become increasingly disconnected from the compensation it is paid. Additive to the gulf between what ratepayers are paying for this resource and its value are costs to integrate the solar fleet as it stresses the distribution system. Meanwhile, costs to serve load during non-solar hours and days remain. All these additional costs add to rate pressure, and keeping electric rates low is one of the most important measures Vermont can take to encourage electrification – and thus decarbonization – of the carbon-heavy heating and transportation sectors. A comprehensive approach to decarbonization, electrification, increasing renewables, grid modernization, and managing rates and costs is thus imperative to achieving Vermont's energy and climate goals in a least-cost manner.

Best Practices in Net Metering

Nationally, traditional net-metering – which typically involves crediting a customer for excess generation at the full retail rate the customer pays for energy services from the grid – is the most common program for customers who deploy small-scale generation. According to the North Carolina Clean Energy Technology Center, as of August 2021, 39 states, the District of Columbia, and four U.S. Territories had mandatory rules regarding net-metering programs.[151]

[151] North Carolina Clean Energy Technology Center, DSIRE. N*et Metering Policies (Updated June 2020)*. Retrieved from https://www.dsireusa.org/resources/detailed-summary-maps/

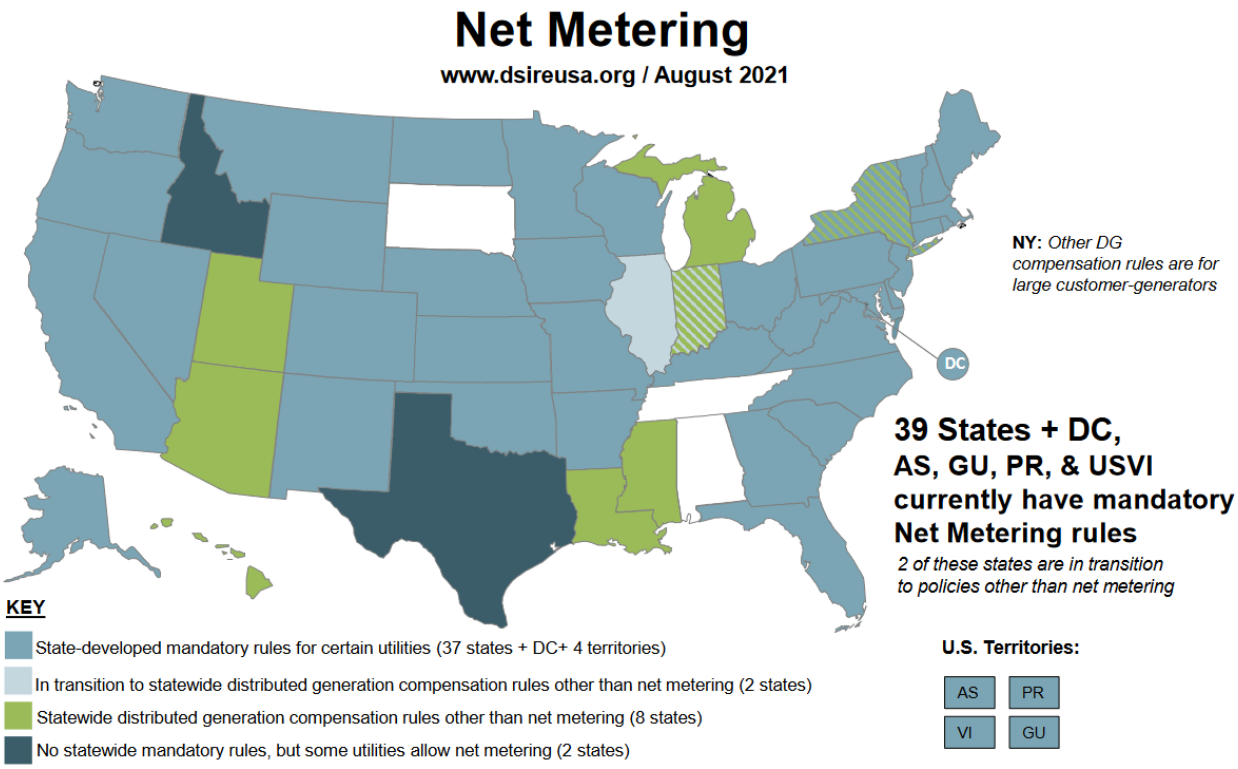

Figure 64: Summary of states with net metering rules

While traditional net-metering programs have helped stimulate the markets for small-scale, renewable distributed generation, as these programs have matured, a growing number of states (including Vermont) have started to explore and/or transition to alternative programs to support these resources. These reviews have been spurred by numerous reasons including:[152]

- Hitting previously established aggregate systems caps for traditional net-metering
- Proposals by utilities for alternative structures that better reflect the value these resources provide to the grid
- Concerns that net-metering customers are not fairly contributing to utility fixed costs and/or are being subsidized by non-participating customers
- Other legislative or regulatory requirements

Outside of Vermont, a growing number of states either have transitioned or are in the process of transitioning to alternative compensation structures for distributed generation. New net-metering and distributed generation programs focus on shifting several aspects of traditional net-metering rate designs in efforts to more accurately reflect the value of these resources to the grid and cost-shifts among customers, including: the rate at which excess generation is compensated; treatment of fixed charges and minimum bills for customers; and even creating separate customer classes

[152] Stanton, T. (2018). R*eview of State Net Energy Metering and Successor Rate Designs.* Retrieved from https://pubs.naruc.org/pub/A107102C-92E5-776D-4114-9148841DE66B/

for customers who own distributed generation resources.[153] In Q3 of 2022 alone, 40 states and the District of Columbia took 174 actions on distributed solar policy and rate design, with the top three actions involving distributed generation compensation rules (taken by 26 states, 33% of actions), community solar (22 states + DC, 26% of actions), and residential fixed charges or minimum bill increase (18 states, 16% of actions).[154]

As markets for solar and other distributed generation technologies have matured, many states have made concerted efforts to move away from traditional net-metering programs and identify alternative compensation mechanisms. These new programs aim to reflect the value these resources currently provide to the grid more accurately and reduce cost shifts to non-participating customers. The prior version of this report provided a detailed list of alternative structures under consideration by various states.[155] This report focuses on the most significant recent change in the last year: the modifications made to California's net-metering program finalized in mid-December 2022.

On December 15, 2022, the California Public Utilities Commission ("CPUC") adopted a proposal to shift from a net-metering framework to a net-billing framework for new systems starting in April 2023.[156] In a net-metering framework, a customer's net-metering system production is netted with their consumption, and any excess generation is credited at (or based on) the customer's retail rate. Customers with systems that are oversized for their load can therefore use full-retail-rate-value credits to offset their consumption even when their systems aren't producing any power, and they are physically leaning on grid power (in the winter, for example). Further, production from large, virtual systems – which are directly connected to the grid don't physically supply their associated customers at all – is entirely credited at a retail-based rate. In a net-billing framework, compensation for excess generation is made at a rate other (and usually lower) than the retail rate.

The CPUC's net-billing framework consists of the following primary elements:

- Requires participating customers to be on "electrification rates." Net-metering customers were already required to be on time-of-use rates; electrification rates exaggerate the delta between peak- and off-peak pricing, encouraging customers to use their solar plus battery storage, to time-shift consumption away from high-demand hours (which are also the most expensive, highest-emission hours).

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[153] Stanton, T. (2018). R*eview of State Net Energy Metering and Successor Rate Designs. R*etrieved from https://pubs.naruc.org/pub/A107102C-92E5-776D-4114-9148841DE66B/

[154] North Carolina Clean Energy Technology Center, The 50 States of Solar: Q3 2022 Quarterly Report, October 2022. Retrieved from https://www.dsireinsight.com/s/Q3-22_SolarExecSummary_Final.pdf

[155] https://publicservice.vermont.gov/sites/dps/files/documents/Pubs_Plans_Reports/Legislative_Reports/2021%20Annual%20Energy%20Report%20Final.pdf, Appendix E

[156] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/net-energy-metering/nem-revisit

- Credits excess generation based on its time of export to the grid, which is in turn based on the avoided cost to the utility of procuring energy at that time.
- Provides extra bill credits to participating customers for the next five years, as well as to low-income customers[157]

The CPUC wrote in their final decision:

> *A review of the current net energy metering tariff, referred to as NEM 2.0, found that the tariff negatively impacts non-participating ratepayers, disproportionately harms low-income ratepayers, and is not cost-effective. This decision determines that, to address the requirements of the guiding principles and the findings related to the NEM 2.0 tariff, the successor tariff should promote equity, inclusion, electrification, and the adoption of solar paired with storage systems, and provide a glide path so that the industry can sustainably transition from the current tariff to the successor tariff and from a predominantly stand-alone solar system tariff to one that promotes the adoption of solar systems paired with storage.*
>
> *In the successor tariff, the structure of the NEM 2.0 tariff is revised to be an improved version of net billing, with a retail export compensation rate aligned with the value that behind-the-meter energy generation systems provide to the grid and retail import rates that encourage electrification and adoption of solar systems paired with storage. The successor tariff applies electrification retail import rates, with high differentials between winter off-peak and summer on-peak rates, to new residential solar and storage customers instead of the time-of-use rates in the current tariff. The successor tariff also replaces retail rate compensation for exported energy with Avoided Cost Calculator values that vary according to grid needs. The high differential electrification retail import rates in combination with the variable retail export compensation rates provided by the Avoided Cost Calculator send strong price signals to customers to shift their use of energy from the grid to mid-day and export electricity during the evening hours, which promotes the installation of storage with the solar systems. These price signals also benefit customers who electrify their vehicles, home devices, and appliances. The changes will improve the reliability of electricity in California and reduce greenhouse gas emissions.*[158]

In Case 19-0855-RULE, the Commission explored net-metering compensation, in addition to other aspects. In its November 1, 2019, comments,[159] the Department recommended moving to a compensation structure that would minimize cost-shifts of Vermont's net-metering program, estimated to be $49 million in above-market costs in 2021 alone (see Table 3 above). The

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[157] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/net-energy-metering
[158] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M500/K043/500043682.PDF
[159] November 1, 2019: Department of Public Service Report on Public Utility Commission Net-Metering Information Requests (19-0855-RULE), pp. 14-18

recommended structure is simpler than that adopted in California: it would value excess generation based on a levelized value of avoided cost, set at the time the project is permitted and fixed for 10 years. Customers with behind-the-meter systems would still net out consumption – in real time and in a billing cycle – at retail rate, so they would see very little change in the system economics. Large, virtual systems would be compensated at a value closer to that any other large, standalone solar system (such as a Standard Offer project) would receive, which would dramatically lower the above-market costs ratepayers pay for the net-metering program, given the degree of excess generation in the program (over 75% of generation from net-metered systems, per Table 3 above).

In its May 27, 2022 comments in the same case, the Department recommended that the Commission open a proceeding once the CPUC had issued a final order in its net-metering rulemaking – given similarities in the issues under consideration in both states – to look specifically at reforming net-metering compensation.[160] In its December 7, 2022 Order in 19-0855-RULE, the Commission asked for comments on further changes to Rule 5.100 and indicated that it intends to address compensation through a different proceeding. [161] The Department looks forward to the opportunity presented by this proceeding to better align net-metering compensation with its value to ratepayers, to ensure the program's sustainability and positive contribution to meeting Vermont's energy and climate requirements.

Conclusion

Net-metering has made important contributions to Vermont's energy supply mix; however, after more than 20 years, hundreds of megawatts of installed projects, and an understanding of the premium paid by ratepayers for resources in this program, it is past time for an overhaul of the net-metering compensation structure. The primary resource developed under net-metering is solar generation, which is also being developed through competitive solicitations at substantially lower costs. It is imperative that the state be willing to take an objective view of current programs in order to properly evaluate what programs will meet Vermont's future energy policy and best serve Vermonters. The Department has embarked on a stakeholder process to review Vermont's electricity procurement programs, including the Renewable Energy Standard and its supporting programs such as net-metering, Standard Offer, and utility-owned or contracted projects. The Department looks forward to engaging with many different types of stakeholders to discuss attributes of a modern, sustainable, adaptable, grid-friendly compensation framework for distributed generation.[162]

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[160] May 27, 2022: Department of Public Service Comments to the Vermont Public Utility Commission's Request for Comments on Draft Rule, pp. 1-2

[161] December 2, 2022: Order Regarding Further Proposed Revisions to Commission Rule 5.100 and Request for Comments (Case No. 19-0855-Rule), p. 18

[162] http://publicservice.vcms9.vt.prod.cdc.nicusa.com/announcements/psd-releases-proposed-public-engagement-plan-review-vt-renewable-electricity-policies

Appendix D: Report on the Vermont Small Hydropower Assistance Program

The Vermont Small Hydropower Assistance Program (VSHAP) was established to determine whether hydropower projects might qualify as "low impact" and help such projects navigate the *state resource agency components* of the federal process to obtain a permit (called a license or exemption) from the Federal Energy Regulatory Commission (FERC). FERC permits are required for projects that affect interstate commerce (by virtue of connecting to the grid). FERC must also meet obligations under the federal Clean Water and National Historic Preservation Acts, in part through consideration or inclusion of recommendations or conditions from the state resource agencies dealing with environmental and historical resources.

The VHSAP program, which was developed by the Department, Agency of Natural Resources, and Agency of Commerce and Community Development in response to Act 165 of 2012, is entirely voluntary. Several small hydropower projects have been developed in Vermont in the last decade without participating formally in the program, and others are in various exploratory phases. The program involves a two-step screening process. The first step involves a desktop review of project proposal characteristics, while the second step is based on a site visit (and predicated on successful screening through the first step). For projects that screen as low impact, the agencies will seek to offer support where possible and as appropriate (for instance, agreeing to waive scoping periods in the FERC process and/or representing to FERC that agency concerns have been satisfied). Proposals to add hydropower to existing dams, or repower formerly powered sites, are examples of the types of proposals reviewed under the two-step process.

Two new applications were received in 2022:

- A 15 kW project involving restoration of the Reservoir Road Dam in Westfield, VT, whose developer had previously engaged extensively with state resource agencies. The project was thus able to skip the second step of the VSHAP process and was issued a letter to include in its exemption application to FERC stating that the state resource agencies' concerns had been satisfied, and that they were amenable to waiving scoping periods and consultation and in support of shorter comment periods, as long as certain conditions were included in the FERC exemption.
- A 150 kW project in Rutland in a disused canal structure adjacent to Wilk Paving Asphalt Plant at the historic Ripley Mill site on Otter Creek. This project submitted a Step 1 application, which was followed by a site visit by the resource agencies. The agencies communicated the studies and additional information needed to make final Step 2 determinations to the applicant in mid-November.

At this time, the Department recommends discontinuing the VSHAP program. When applications come in—though infrequent—it requires considerable staff resources that must be reallocated from other core Department functions. To the Department's knowledge, none of the projects that have engaged under VSHAP have proceeded to construction. Additionally, it is confusing to applicants, who misunderstand the extent to which assistance can be provided and assume state staff will help them navigate and execute every aspect of their FERC application,

from studies to writing application documents. To the extent the legislature is interested in facilitating small hydropower development, the most helpful assistance would be to provide funding directly to hydropower developers to assist them in hiring consultants to complete studies and to develop and submit FERC license applications.