Appendix B: Report on Renewable Energy Programs

2024 Annual Report on the Renewable Energy Standard

Vermont Department of Public Service

January 15, 2024

Submitted to 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

1. Introduction

Pursuant to 30 V.S.A. § 8005b, the Department of Public Service (PSD or Department) provides this annual assessment of the historical and ongoing impacts of the current Renewable Energy Standard (RES).

The annual report, as set forth in subsection (b) of Section 8005b,[1] must address three issues:

1. An assessment of costs and benefits of the RES based on the most current available data;
2. Projected impacts of the RES on electric utility rates, total energy consumption, electric energy consumption, fossil fuel consumption, and greenhouse gas emissions; and
3. An assessment of RES compliance to date and whether the Department recommends any changes.

To address these issues, the report proceeds as follows:

- First, the report provides a summary of the RES and related requirements.
- Next, the *Summary of Program Performance to Date,* offers a retrospective evaluation of the historical performance of the RES program with respect to costs and benefits, with a focus on 2022 performance.
- The section on *Methodology and RES Model Overview* describes the mechanics of the Consolidated RES Model, the tool used to support quantitative projections of potential future impacts of the RES in Vermont. This section discusses underlying historical data, current trends and assumptions, and uncertainties around those assumptions in this modeling effort.
- *Projections of Future Program Performance,* summarizes the results of modeling exercises undertaken by Department to estimate future impacts of RES on Vermont, considering issues such as rate pressure, energy consumption, and greenhouse gas emissions.
- The final section, *RES Compliance and Recommended Changes,* presents an assessment of whether the RES requirements have been met to date and any recommendations for change by the Department.

The report also includes three appendices. Appendix I contains the statutory language describing the purpose and requirements of this report; Appendix II summarizes the public comments received on the draft model and changes made to the model in response; Appendix III lists the values assigned to the key modeling variables that drive different results in the Department's scenario analysis model.

1.1 Summary of Findings

Before proceeding to the main report, the Department highlights several key findings from the modeling exercise:

- In the 2022 compliance year, all Vermont Distribution Utilities (DUs) met or exceeded their RES requirements. Compliance costs, which include the costs of those utilities who elected to exceed their RES obligation, for 2022 were approximately $28 million. These cost estimates consider Renewable Energy Credit (REC) purchases, overhead, and Tier III incentives.[2]

- Utility compliance with the RES will mean significant ongoing reductions in fossil fuel consumption by Vermonters, primarily through the greening of the State's electricity supply and the electrification of both transportation and heating. The Department estimates that Vermonters will reduce fossil fuel consumption over the next 10 years by a total of approximately 177,000,000 mmBtu, and carbon dioxide (CO_2) emissions

[1] Appendix I of this document contains the relevant language of Section 8005b.

[2] These costs do not consider the additional utility revenues generated by Tier III electrification measures that offset the costs of implementing the program.

by roughly 7,700,000 tons as a direct result of the RES.[3] Valuing these emissions using the Social Cost of Carbon[4] results in approximately a $913 million benefit.

- The Department's annual assessment of the RES continues to show there will likely be upward electricity rate pressure associated with RES. The Department estimates the net cost of continuing to meet RES obligations over the next ten years will have a net present value (NPV) cost of roughly $105 million (assuming a 6% discount rate). Under its baseline load forecast, the Department estimates an annual average rate impact of about 1.2% over the analysis period, with one scenario resulting in retail rates less than 0.63% higher over the next ten years, and other scenarios with rates over 4% higher. This estimate includes the expectation that Tier III of RES will increasingly put downward pressure on rates to some degree by increasing revenues from higher electric sales. Given the large quantity of RECs required for compliance, a relatively small difference in REC prices can result in a large difference in costs.
- Within the RES Model, the primary drivers of utility compliance expenditures include REC prices, net-metering adoption rates, Tier III incentive costs, and whether new load increases peak loads. It is important to note that this model does not include costs associated with Transmission and Distribution (T&D) investments required to accommodate additional load from electrification or the deployment of distributed generation assets.
- The initial compliance years of RES, combined with the Department's modeling, suggests the RES creates moderate upward rate pressure while producing meaningful reductions in fossil-fuel usage and greenhouse gas emissions. If utilities meet Tier III requirements with measures that increase electric load and that do not contribute to peak loads, the increased consumption of electricity will spread utility costs over a greater volume of sales, mitigating the upward pressure on rates associated with RES compliance expense.
- Please note that separate from the analysis or finding detailed in this report - the Vermont Public Service Department engaged in a broad review of our current state electricity policies and programs, as recommended by the state Comprehensive Energy Plan and Climate Action Plan. That effort included an assessment of a variety of different potential changes to the RES that would achieve 100% renewable or carbon-free supply as well as their potential costs and benefits. This exercise modeled hypothetical future 100% Renewable or Clean Energy Standard law options and changes to eligibility criteria of current resources. It did not consider Tier III energy transformation projects.

2. Overview of RES and Reporting Requirement

Section 8 of Public Act No. 56 of 2015 (Act 56) directed the Public Utility Commission (PUC) to implement a renewable energy standard (RES), by means of "an order, to take effect on January 1, 2017." This requires Vermont's distribution utilities (DUs) to retire a minimum quantity of renewable energy attributes or Renewable

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[3] This is based on modeling conducted on the Department's "baseline" load forecast under the base case, or "most likely" cost scenario, assumptions.

[4] In 2021, the Science and Data Subcommittee of the Vermont Climate Council recommended that the Social Cost of Carbon 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 Global Warming Solutions Act (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

Energy Credits (RECs), and to achieve fossil-fuel savings from energy transformation projects.[5] 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. This amount increases by 4% every third January 1 thereafter, up to 75% in 2032. A utility can also make an Alternative Compliance Payment (ACP) in lieu of retiring Tier I 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."[6]

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. Like Tier I, a utility can make an ACP in lieu of retiring Tier II RECs. Pursuant to Section 8005(a)(1)(C), Tier II resources also count toward a DU's Tier I requirement. Additionally, to the extent that a DU is 100% renewable, the DU is not required to meet the annual requirements set forth in Tier II but is required to accept net-metering systems and retire the associated RECs.[7] [8]

The implementation of REC retirements for RES Tier I and Tier II in Vermont is consistent with how the rest of New England demonstrates renewable energy compliance. 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 but did not require utilities to serve their load with renewable energy or to retire RECs. The use of RECs to track renewability is the generally accepted standard across the country.

Act 56 also created Tier III, which requires DUs to achieve fossil-fuel savings from energy transformation projects or retire Tier II RECs. For Tier III, the RES requires savings of 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 no obligation until 2019. Energy transformation projects implemented on or after January 1, 2015 are eligible to be counted towards a DU's Tier III obligation. Like Tiers I and II, a utility can make an ACP in lieu of achieving sufficient fossil fuel savings or retiring Tier II RECs. Eligible 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, deployment

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[5] 30 V.S.A. § 8005(b).

[6] 30 V.S.A. § 8015(c).

[7] Net-metering RECs assigned to the DU by net-metering customers in exchange for additional net-metering compensation must be retired per Section 5.127(B)(1) of Rule 5.100 and 30 V.S.A. § 8010(c)(1)(H)(ii).

[8] 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 (contracted or owned) 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.

of electric vehicles or related charging infrastructure, and other custom projects. The Tier III requirements are additional to the Tier I requirements.

3. RES Performance to Date

Pursuant to the PUC's *Order Implementing the Renewable Energy Standard*, issued in Docket 8550 on June 28, 2016 and PUC Rule 4.419, Vermont utilities must submit annual RES filings by August 31st each year to demonstrate compliance with their obligations. In each year the RES has been in effect (2017 – 2022), the Department filed comments stating that in its review of the utilities' compliance filings, all utilities demonstrated compliance with Tiers I and II of the RES by retiring qualifying RECs in the NEPOOL GIS for the compliance year. In each year, the PUC has found all the utilities to be in compliance with their RES obligations.[9]

On June 1 of each year, the Department files a Tier III Verification Report. The report provides the results of the Department's verification of each utility's Tier III savings claims. The Department compares each utility's August RES compliance reports with the June 1, Tier III Verification Report. For each year of the RES, including 2022, the Department has found the Tier III credits reported by the utilities to be consistent with the verified Tier III savings claims and sufficient to meet each utility's Tier III savings requirements.

Table 1, below, provides an overview of 2022 RES compliance by Tier for each utility in the state.

Utility	2022 REC Retirements and Tier III Savings as Percent of Sales		
	Tier I	Tier II	Tier III
Barton	59.9%	4.0%	4.0%
Burlington	102.7%	0.0%	5.3%
Enosburg Falls	59.9%	4.0%	4.0%
Green Mountain Power	80.0%	4.0%	5.3%
Hardwick	59.9%	4.0%	4.0%
Hyde Park	59.0%	4.0%	4.0%
Jacksonville	59.9%	4.0%	4.0%
Johnson	59.9%	4.0%	4.0%
Ludlow	59.9%	4.0%	4.0%
Lyndonville	59.9%	4.0%	4.0%
Morrisville	59.9%	4.0%	4.0%
Northfield	59.9%	4.0%	4.0%
Orleans	59.9%	4.0%	4.0%

[9] See Commission Orders in Dockets 17-4632-INV, 19-0716-INV, 20-0644, 21-1045-INV, 22-0604-INV, and 23-0773-INV.

Stowe	59.0%	4.0%	4.0%
Swanton	100.0%	0.0%	4.0%
Vermont Electric Cooperative	59.0%	4.0%	5.3%
Washington Electric Cooperative	101.0%	4.0%	5.3%
Vermont Total	**78.2%**	**3.7%**	**5.2%**

Table 1. REC retirements as a percentage of retail sales 2022 by utility and RES Tier

In 2022, utilities met their Tier I obligation by retiring RECs from a variety of resources including owned hydroelectric facilities, long-term Hydro-Quebec bundled purchases, and regional hydroelectric REC-only purchases, among others. In 2022, utilities satisfied their Tier II obligations through primarily solar resources, including continued growth in net-metering (almost entirely solar), Standard Offer projects, and in-state solar, both utility and merchant owned. Figure 2 illustrates REC retirements by resource for both Tiers I and II.

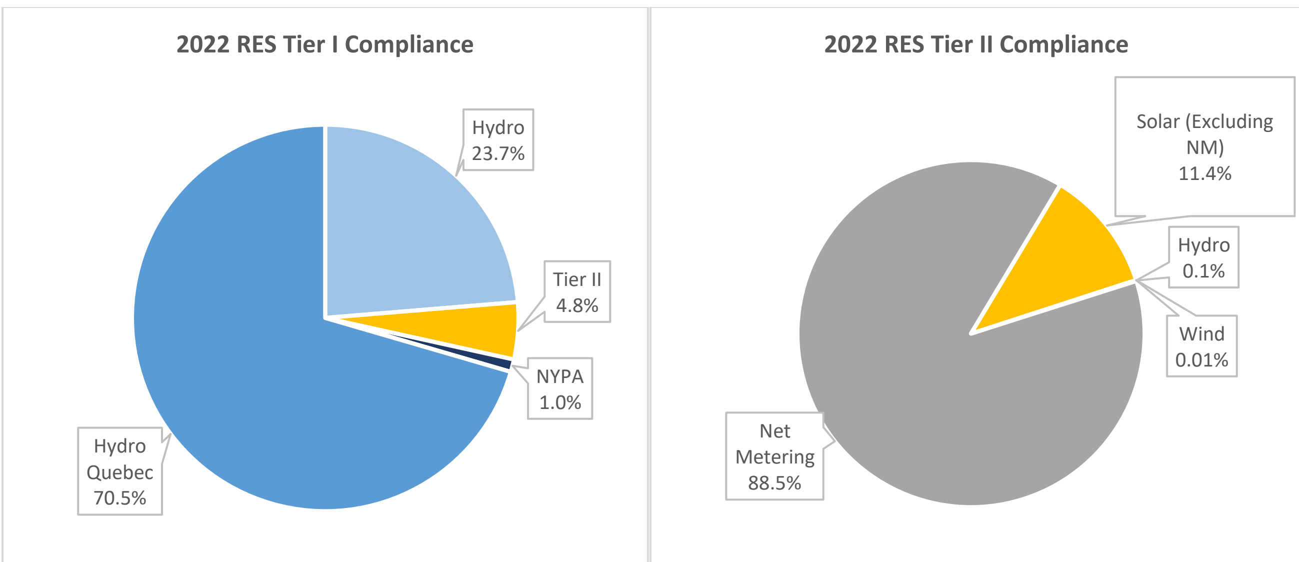

Figure 1. 2022 Tier I and Tier II REC retirements

Vermont utilities met their Tier III obligations with a variety of measures. Over 50 percent of Tier III savings came from some form of cold climate heat pump technology. The remainder of savings came from custom commercial and industrial projects, 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 2022.

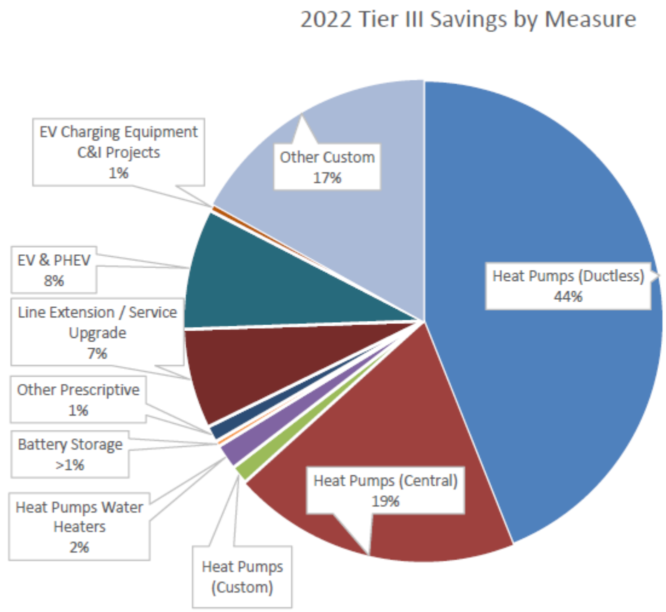

Figure 2. 2022 Tier III compliance measures

Table 2 summarizes key metrics on 2022 RES performance. Compliance costs for 2022 were estimated to be about $28 million, compared to maximum potential costs of $66.7 million.[10] Carbon dioxide (CO_2) emissions were reduced by approximately 667,810 tons from 2016 emissions.[11] This shift to more owned renewable attributes, combined with an increased share from nuclear energy, brings Vermont's average emissions rate down to 68.9 pounds of CO_2 per MWh compared to the latest regional New England average of 654 pounds per MWh in 2021.[12]

2022 RES Performance			
	REC Retirements		*Compliance Cost*
Tier I	4,244,395	RECs	$6,004,996
Tier II	203,726	RECs	$9,256,678
Tier III	616,773	Mwhe	$12,971,255
Total Cost of Compliance			**$28,232,929**
Retail Sales	5,429,966	kWh	
Rate Impact of RES Compliance	3.1%		
CO_2 Reduction from RES	667,810	tons of CO2	
Vermont Emissions Profile	68.9	lbs per MWh	

[10] Maximum potential costs reflect what the costs would have been if the ACP was paid to meet all 2022 RES requirements.
[11] In addition to CO_2 reductions directly resulting from RES, Vermont's electric mix was 16% nuclear in 2022 compared to 12% 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.
[12] https://www.iso-ne.com/static-assets/documents/2023/04/2021-air-emissions-report.pdf

Table 2. 2022 RES performance metrics

4. Projections of Future Performance

4.1 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.[13] 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 emissions 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 Projections of Future Program Performance*. Appendix 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.

4.1.1 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 CO_2 reductions (i.e., the cumulative greenhouse gas (GHG) emissions 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., 2023-2032 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.[14]

4.1.2 Loads

Annual RES obligations are based on a utility's retail sales in the compliance year. For the 2024 RES Modeling effort, the Department included a modeling sensitivity around load forecasts, developing two forecasts under which to project potential impacts of the RES: a baseline load forecast and high load forecast.

[13] The RES Model is available on the Department's website at: https://publicservice.vermont.gov/about-us/plans-and-reports/renewable-energy-standard-reports

[14] 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 2022 emissions accounting because they are known, but the model's 10-year estimates do not assume continued over-compliance.

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.[15] VELCO is currently working on their 2024 Long-Range Transmission plan, however, at the time of publishing this report it is not yet complete. When that plan is finalized, it will be utilized in subsequent RES modeling exercises. The baseline LRTP forecast of 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 Plan (CAP).[16] 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.[17]

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

4.1.2.1 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 2032.

[15] 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.

[16] 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.

[17] The LEAP model has been updated since adoption of the CAP in 2021, and this year's model reflects the latest LEAP modeling Central Mitigation Pathway as of March 19th, 2023.

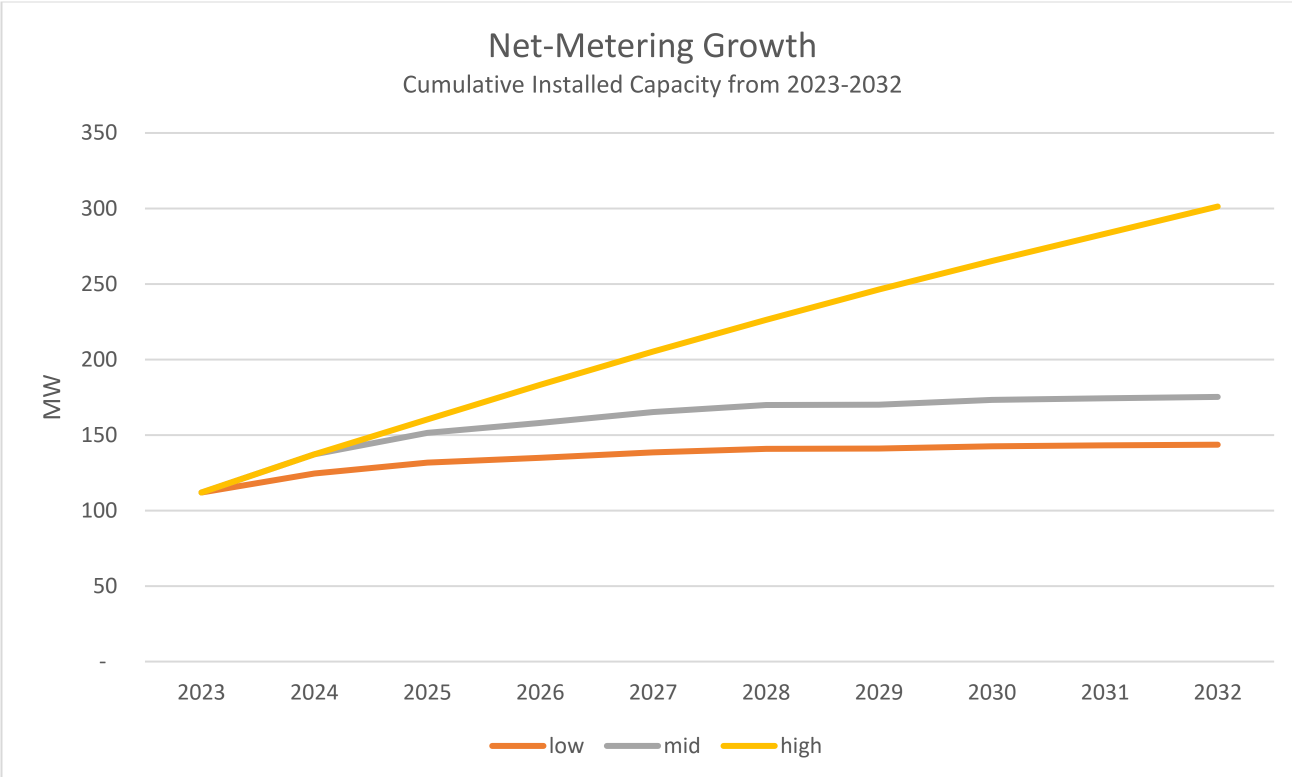

Figure 3. Net-metering growth scenarios

4.1.2.2 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.

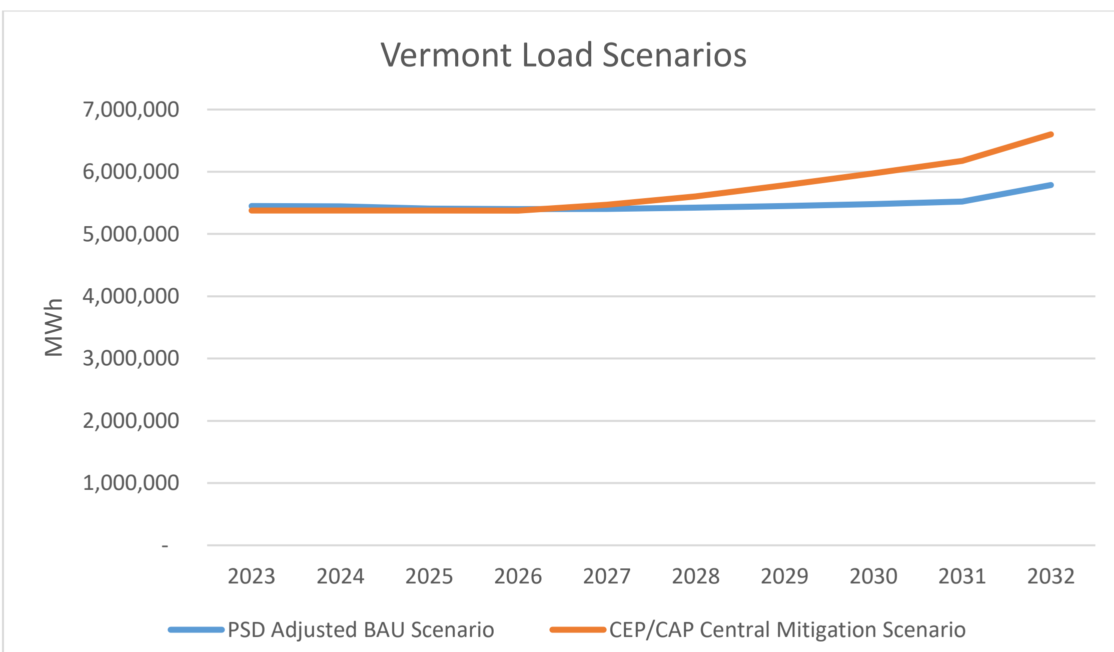

Figure 4. Baseline and high load forecast, 2023-2032

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.

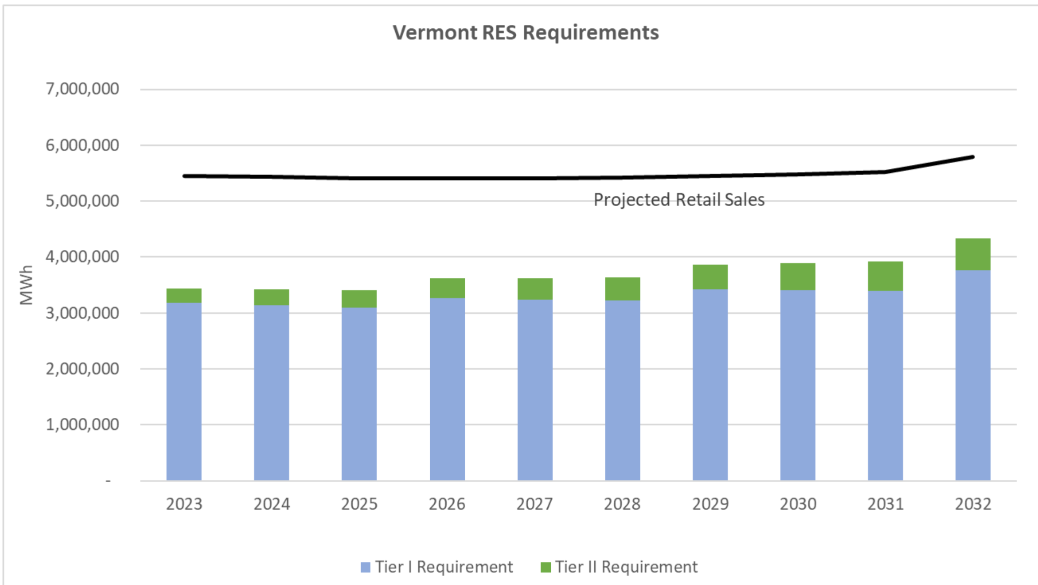

Figure 5. Projected retail sales and RES requirements under the baseline load forecast

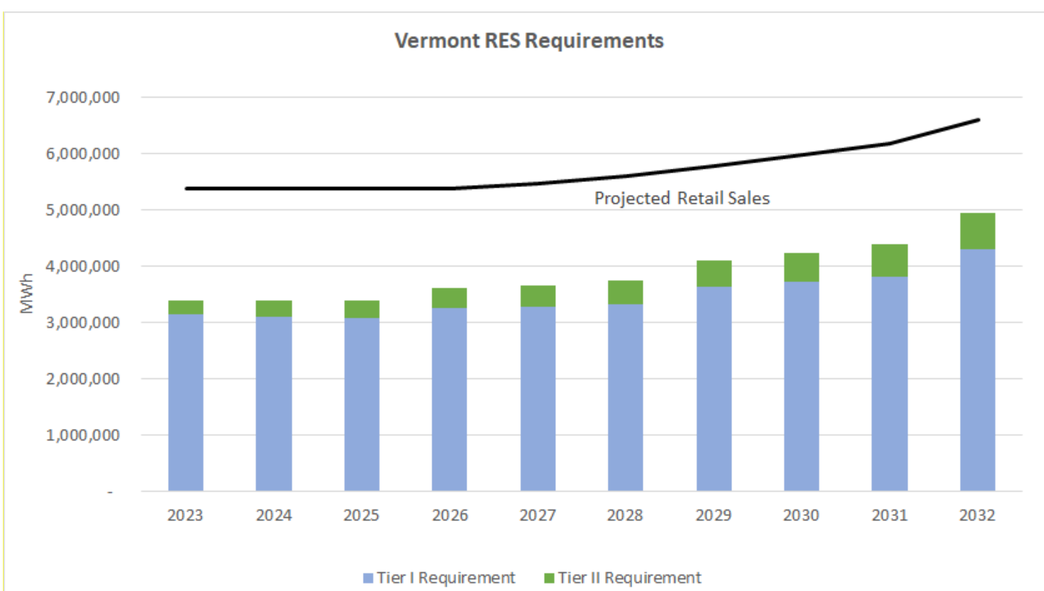

Figure 6. Projected retail sales and RES requirements under the high load forecast

4.1.3 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, the Department expects RECs will be available for purchase at prices lower than the ACP and consistent with premium RECs in other New England states.

Understanding the relationships among different regional REC markets helps with understanding 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. It follows that Vermont Tier I prices have historically been similar to Class II prices in neighboring states.

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 $11.16/REC and Tiers II and III were $66.94/REC in 2022; 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.

4.1.4 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 toward 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 toward clean energy requirements and create carve-outs within clean energy and renewable requirements to maintain existing resources. For example, both New York[18] and Massachusetts[19] 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. While Tier I RECs have traded around $1/REC in past years and risen as high as $8-$12/REC in 2021, prices have declined to somewhere between $4-$7 depending on which benchmark price indicator is used.[20]

Despite the recent volatility 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 $6.72/REC over the 10-year period, with prices starting at $6/REC in 2023 and escalating to $7.13/REC in 2032. The low case starts at the same $4/REC price in 2023 escalating to $4.75/REC in 2033. The high case averages $13.15/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 hydropower 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 forecasts

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

[19] 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

[20] The Department has previously relied on Maine Class II Existing Renewables REC prices as indicative Tier I prices, however, new more narrow qualification standards in Maine have made this comparison less comparable to Tier I. The inception of new resource classes such as Massachusetts "Clean Energy Standard - Existing" attributes are likely more indicative of Tier I prices going forward as a more broadly traded asset.

4.1.5 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. The Tier II base-case assumes an average prices of $35.76/REC over the 10-year modeling period based on the same price forecast utilized by the Department's consultant hired to conduct technical analysis on potential 100% clean or renewable energy standards.[21] The low case assumes 10% lower prices than the base scenario beginning in 2027, and the high case assumes 5% higher prices than the base scenario beginning in 2027. The future of new regional renewable supply and demand remain uncertain, but there are several critical offshore wind projects that create a potential inflection point around 2027, depending on whether those projects come online as scheduled.

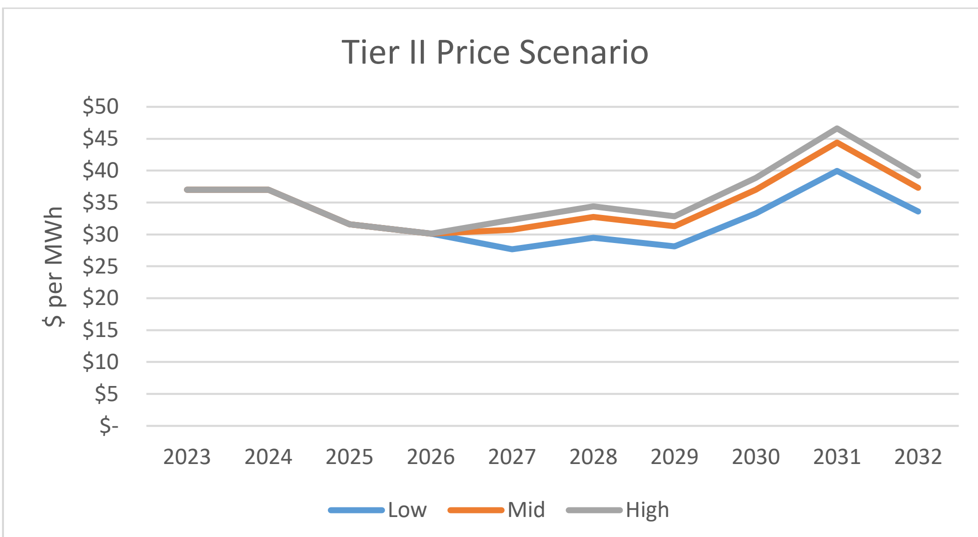

Figure 8 Tier II price forecast

4.1.6 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)

[21] All work products and meeting materials from the Department's 2023 Technical Analysis and associated Stakeholder Advisory Group, including the final model of 100% clean/renewable energy scenarios, can be found on the Department's Renewables webpage here: https://publicservice.vermont.gov/renewables

Niagara Project[22] that come at no additional cost. The forecasted Tier I REC price is then applied to the balance of the obligation.[23] 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,[24] 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. By not fully modelling the banking of RECs, the cost of RES is overstated in the high REC price scenario due to the steep upward slope of forecasted Tier I REC prices. In the model, instead of using banked RECs in future years, the utilities are expected to sell excess RECs in the near term at low prices, then acquire RECs in future years at higher prices.

The RES model projects costs assuming that Vermont utilities will meet the RES requirements. However, several Vermont utilities have exceeded RES requirements in the first six 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 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 very low cost, to date. These deviations from explicit RES requirements are not captured in the forward-looking modeling of the RES Model.

4.1.6.1 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. Tier II of the 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.

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

[23] 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.

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

			RECs		CATEGORY				
Program	CPG Application Date	Statewide Blended Rate	Transfer to Utility	Retain Ownership	I	II	III	IV	Hydro
NM 1.0[30]	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	$0.17141	$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 toward 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 $35/REC, so at $40, DUs are acquiring net-metered RECs 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 future projections.

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

Several eligible Tier III measures offer sources of new load for utilities.[25] The RES model allows the user to specify which Tier III measures utilities will incentivize to meet their obligations.[26] 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

[25] 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.

[26] 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.

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 as 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	
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 over 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 pathways, strategies, or actions of the Comprehensive Energy Plan or Climate Action Plan recently adopted pursuant to the GWSA.[27] 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, 2021, and 2022 compliance years, a large percentage of savings were derived from the installation of cold climate heat pumps. Electric vehicle adoption as a been relatively lower portion of Tier III savings claims so far 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.

4.1.8 Tier III Compliance Cost Components

4.1.8.1 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

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

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 2032, prices will be 63% higher or 10% lower than they are today. The low fossil-fuel price 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 30% of rates, and includes costs associated with energy, capacity, and transmission.[28] 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.

4.1.8.2 Program Administration Overhead

Utilities incur 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 2023, escalating by 3% thereafter.[29] This represents a small share of the total compliance expenditure in any scenario. In the early stages of RES, program costs may have significant year-over-year changes as experience leads to gains in efficiency as the programs mature, but programs that capture low-hanging fruit will dry up. Future reports will provide opportunities to refine overhead cost assumptions with historical information.

4.1.8.3 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 two 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 are 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 it 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

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[28] No T&D investments associated with upgrades to accommodate Tier III loads have been included in this analysis.
[29] Actual 2022 overhead costs were reported to be $780,826. See Case No. 23-0773-INV for 2022 RES compliance filings made by utilities.

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.

4.2 Projections of Future Program Performance

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 regard to impacts on total energy consumption and CO_2 reductions (Section 4.2.1) and total cost of RES and related rate impacts (Section 4.2.2).

4.2.1 Projected Impacts on Total Energy Consumption and CO2 Reductions, 2023-2032

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.[30] Additionally, Vermonters indirectly consumed around 22,000,000 mmBtu of fossil fuel through electric usage.[31] 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 4,700,000 mmBtu lower in 2032 attributable to Tier III, a reduction of 4.6% 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 18,300,000 mmBtu in 2032, a reduction of 14.6% relative to 2016 levels.[32]Under the high load forecast scenario, the Department estimates the reduction in end-use consumption of fossil fuels attributable to Tier III in 2032 would be around 5,000,000 mmBtu and that consumption of fossil-fuel based electricity in the Vermont mix would have been reduced by nearly 20,900,000 mmBtu, reductions of roughly 4.85% and 16.7% 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 16% in 2022; that share has decreased from a high of 26% with contract expirations, and the Department has assumed that 16% 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 2032, on an annual basis, Vermont will consume around 18.4% less fossil-based energy than it does today in the baseline load forecast scenario, or approximately 22% less in the high forecast scenario, as a direct result of RES, with an additional 1% reduction resulting from the increased share of nuclear. Similarly, annual carbon dioxide emissions could be reduced by nearly 1,037,000 tons (baseline load forecast) or 1,153,000 tons (high load forecast scenario) in 2032 as a direct result of RES, a reduction on the order of 12% and 13%, respectively, relative to recent levels across all sectors

[30] http://eanvt.org/wp-content/uploads/2018/06/EnergyActionNetwork_AR_2017_AA_final.pdf
[31] Based on 52% of load from ISO-NE residual mix at an average heat rate of 8,000 mmbtu/MWh
[32] 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.

(estimated to be around 7,990,000 tons[33]), with approximately an additional 330,000 tons or 350,000 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[34] results in approximately $144 million (baseline load forecast) or $160 million (high load forecast) of annual societal benefit in 2032, calculated based on the difference between the amount of electricity attributed to the residual mix in 2016 and 2022. On a cumulative basis, over the period of 2023-2032, under the most likely cost scenario, the Department estimates the RES could lead to over 8,100,000 or 8,400,000 tons of CO_2 saved in the baseline and high load forecast scenarios, respectively. This has a net-present value (NPV) of $878 million or $913 million based on the Social Cost of Carbon. Figure 9 illustrates annual estimated carbon reductions for 2023 to 2032 under each of the load forecast scenarios.

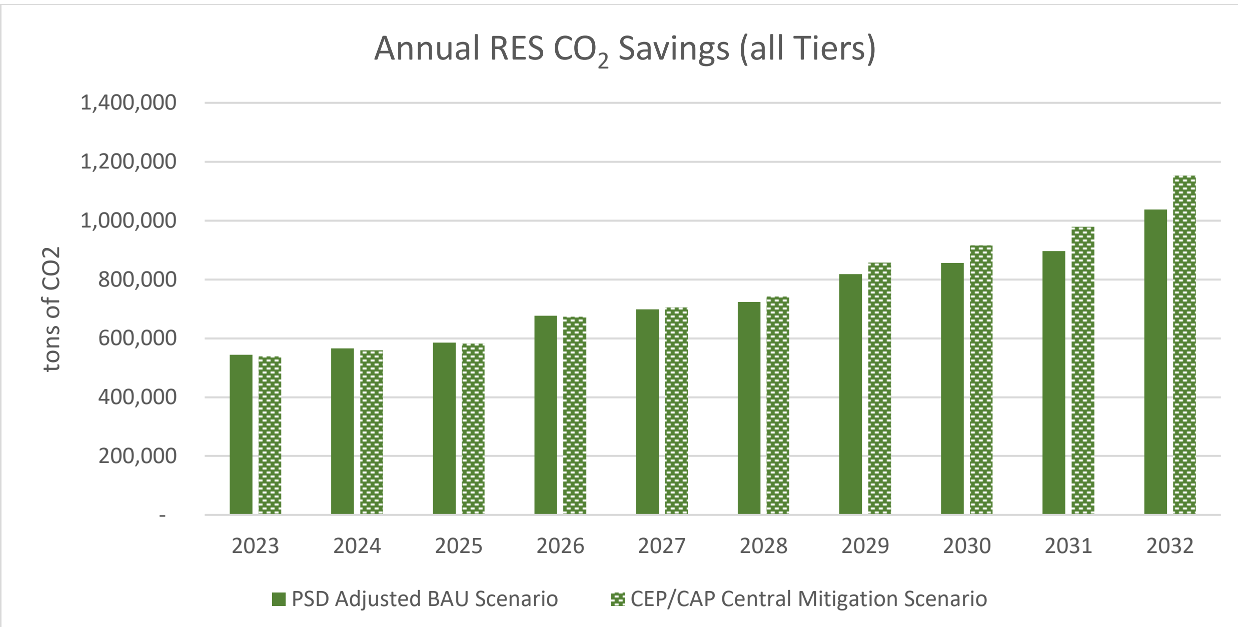

Figure 9. Annual CO_2 savings due to the RES from all Tiers, 2022-2033

4.2.2 Projected Costs of RES, 2023-2032

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 (2023-2032) under the baseline and high load forecast scenarios. Under the baseline load forecast scenario, costs could be as low as $107 million or as high as $255

[33] Vermont Greenhouse Gas Emissions Inventory and Forecast: 1990-2020, published the Agency of Natural Resources, available at:
https://outside.vermont.gov/agency/anr/climatecouncil/Shared%20Documents/_Vermont_Greenhouse_Gas_Emissions_Inventory_Update_1990-2020_Final.pdf

[34] 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.

million (NPV). Under the high forecast scenario projected to meet GWSA requirements, these cost estimates increase to $118 million and $280 million, respectively (NPV).

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	LOW		HIGH	
NM Adoption Rate	LOW		HIGH	
Peak contribution of New Load	10%		75%	
Fossil Fuel Price	HIGH		LOW	
Load Scenario Scenario	Baseline	High	Baseline	High
Tier 1 Cost	**$51,000,000**	**$55,000,000**	**$122,000,000**	**$135,000,000**
Tier 2 Cost	**$118,000,000**	**$122,000,000**	**$120,000,000**	**$125,000,000**
+Tier 3 Cost	*$279,000,000*	*$287,000,000*	*$351,000,000*	*$363,000,000*
-Additional Revenue	*-$341,000,000*	*-$346,000,000*	*-$338,000,000*	*-$343,000,000*
Tier 3 Net Cost	**-$62,000,000**	*-$59,000,000*	*$13,000,000*	**$20,000,000**
TOTAL Cost of RES	**$107,000,000**	**$118,000,000**	**$255,000,000**	**$280,000,000**
Rate Impact	0.63%	0.75%	3.80%	4.12%

Table 4. Results of RES Model analysis under the low and high-cost scenarios, for each load sensitivity

As with the 2021 and 2022 modeling effort, in 2023 the Department continues to see that the most significant difference between the upper and lower bounds in the table above is related to Tier I REC prices. The Department expects Tier I compliance costs to be within a potential range of costs between $51 million (NPV) and $122 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 $55 million (lower bound) and $135 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 RECs. This would also be influenced by any redesign of the RES taken up by the legislature to support achieving GWSA greenhouse gas emissions reduction goals and achieving 100% clean or renewable goals.

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 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 would mitigate upward rate pressure associated with the RES, which would help provide lower electric rates and support successful electrification efforts. The higher 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. The high cost scenario also assumes lower fossil fuel prices requiring higher customer incentives to encourage adoption of electrification measures.

Overall, the Department continues to anticipate that the RES will result in slight upward long-term pressure on retail electric rates. Rate impacts across scenarios are as low as <1% and as high as 4%. In the scenario the Department considers most likely, the cost of the RES results in approximately 1-2% rate impact. Whatever actual RES compliance costs turn out to be, it is certain that ratepayer costs will be mitigated if utilities ensure all new Tier III loads come online as flexible demand-side resources that do not add to existing levels of peak demand.

5. RES Compliance and Recommended Changes

In each annual RES report, the Department is required to assess whether the requirements of the RES have been met to date and recommend any changes needed to achieve RES requirements. To date, all Vermont DUs are meeting or exceeding their Tier I, II, and III RES requirements. On November 29, 2023 - the PUC issued an order in Case No 23-0773-INV on 2022 RES compliance, approving compliance for the 2022 compliance year. Therefore, at this time, the Department does not recommend any specific statutory changes that would be required to meet current RES requirements. However, consistent with the 2022 Comprehensive Energy Plan and 2021 Climate Action Plan, the Department over the past 18 months undertook an extensive stakeholder outreach and technical analysis process to consider design options for a carbon-free or 100% renewable energy standard to support achieving GWSA greenhouse gas reduction requirements.

The results of this engagement are documented in a separate report that will be posted on the Department's website.[35]

[35] https://publicservice.vermont.gov/renewables

Appendix I – 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

Appendix II – Public Comments

Pursuant to the statute, on November 8, 2023, the Department made the draft RES model and all relevant assumptions public on its website and sought public comments.[36] The Department requested input on modeling assumptions related to Tier III measure allocations and incentive levels, net-metering forecasts, and Tier I and Tier II REC price forecasts. While the Department did not receive any public comments on this exercise it utilized many shared inputs such as energy and REC prices forecasts from a separate modeling exercise conducted as part of its comprehensive review of renewable and clean electricity policies and programs.[37]

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

[37] Full public engagement plan and associated activities of the Department's 2022/2023 review of renewable and clean electricity policies and programs available here: https://publicservice.vermont.gov/renewables

Appendix III – 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	+3.3%	+3.3%	+3.3%
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	538 MW by 2032	411 MW by 2032	380 MW by 2032
Tier I REC Price	Avg $14.15 /MWh	Avg $6.72/MWh	Avg $4.48/MWh
Tier II REC Price	Avg $36.93 /MWh	Avg $35.76/ MWh	Avg $33.41/MWh
Energy Price Assumptions			
Fossil Fuel price scenario	Low	Mid	High
Fossil Fuel price trend	-1%/yr	1.6%/yr	+5.0%/yr