2022 Annual Report on the Renewable Energy Standard

Vermont Department of Public Service

January 14, 2022

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 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 2020 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 2020 compliance year, all Vermont Distribution Utilities (DUs) met or exceeded their RES requirements. Net compliance costs, which include the costs of those utilities who elected to exceed their RES obligation, for 2020 were approximately $21 million. These costs estimates consider Renewable Energy Credit (REC) purchases, overhead, and Tier III incentives[2]. This represented a 76 percent increase compared to 2019 compliance costs. Costs in all categories increased between 2019 and 2020, with the largest percentage increase occurring in Tier III incentive costs.

- 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

[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. Starting in 2022, the Department will be collecting information on those revenues and will include them in cost analyses moving forward.

transportation and heating. The Department estimates that Vermonters will reduce fossil fuel consumption over the next 10 years by a total of approximately 153,000,000 mmBtu, and carbon dioxide (CO2) emissions by roughly 7,000,000 tons as a direct result of the RES[3]. A reduction of 7,000,000 tons is the equivalent of lifetime savings associated with over 300,000 electric vehicles. Valuing these emissions using the Social Cost of Carbon[4] results in approximately a $649 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 $168 million (assuming a 6% discount rate). Under its baseline load forecast, the Department estimates an annual average rate impact of about 2.6% over the analysis period, with one scenario resulting in retail rates less than 0.9% higher over the next ten years, and other scenarios with rates almost 5% higher[5]. This estimate includes the expectation that Tier III of RES will lower compliance costs 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. Under a baseline load forecast scenario, the high-versus-low REC price forecast results in a 1.2% difference in rate impacts. The high-versus-low net-metering deployment forecast results in a 1.6% difference in rate impacts. If new load from Tier III measures including cold climate heat pumps (CCHPs) and electric vehicles (EVs) are deployed without controls to avoid adding to peak demand, the rate impact would be about 0.2%. Under a high load forecast scenario (based on meeting requirements of the Global Warmings Solutions Act requirements), these rate pressures are similar for net-metering and peak demand variables, with the high-versus-low REC price forecast resulting in slightly higher, 1.6% different, rate impact. It is important to note that this figure does not include costs associated with Transmission and Distribution (T&D) investments required to accommodate additional load from electrification associated with meeting Tier III requirements. Upgrades could range from a simple relay setting change, which carry minimal costs of around $1,000, to a complete station rebuild, which can be in the millions of dollars. The state of Vermont has more than 250 substations, as an upper bound, if we assume an average upgrade cost of $2 million per station then total costs would be $500 million. If invested over the course of 10 years, this would translate to an additional 7% of rate pressure on average each year over the course of the investments. This is the case in both baseline and high load forecast scenarios.
- The initial compliance years of RES, combined with the Department's modelling, suggests the RES creates moderate upward rate pressure while producing meaningful reductions in fossil-fuel usage and greenhouse

[3] This is based on modeling conducted on the Department's "baseline" load forecast under the base case, or "most likely" cost scenario, assumptions. Under the Departments "high" load forecast, based on the Central Mitigation Scenario for the Climate Action Plan, the Department estimates over the next 10 years the RES could reduce fossil fuel consumption by 177,000,000 mmBTU and carbon dioxide emissions by roughly 8,000,000 tons.

[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

[5] The Department's high load forecast sensitivity, based on the Climate Action Plan Central Mitigation Scenario, produces similar results, with a base case, "most likely" scenario, rate impact of roughly 2.9%, with a high and low range of 5.4% and 0.9% rate impact, respectively.

gas emissions. If utilities meet Tier III requirements with measures that increase electric load 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.

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 Energy Credits (RECs), and to achieve fossil-fuel savings from energy transformation projects.[6] 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."[7]

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 towards 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.[8] [9]

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.

[6] 30 V.S.A. § 8005(b).

[7] 30 V.S.A. § 8015(c).

[8] 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)

[9] 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.

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 Tier's 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 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

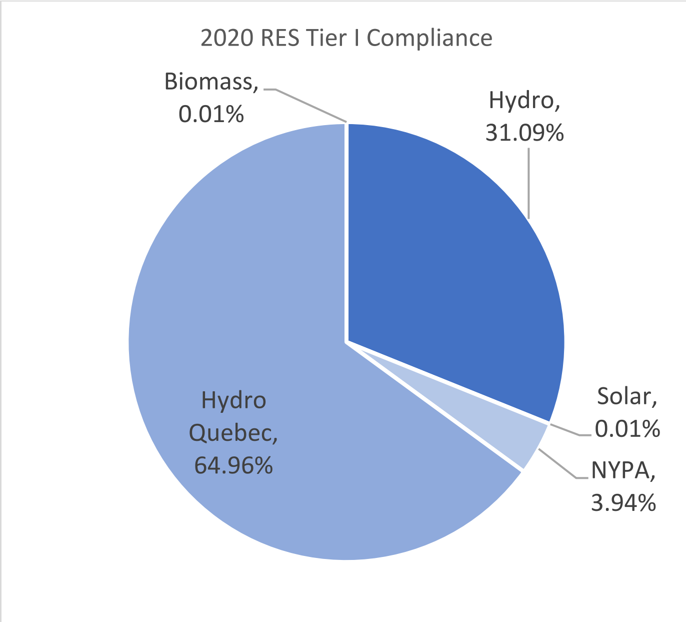
Pursuant to the PUC's *Order Implementing the Renewable Energy Standard*, issued in Docket 8550 on June 28, 2016, Vermont utilities must submit annual RES filings by August 31st each year to demonstrate compliance with their obligations. To date, in each year the RES has been in effect, the PUC has found all the utilities to be in compliance with RES obligations[10]. This continued for the 2020 RES Compliance year. On November 23rd, 2021 the PUC issued an order in Case No 21-1045-INV concluding all utilities had again met their obligations. In that case, the Department filed comments regarding its review of the compliance filings stating that utilities demonstrated compliance with Tiers I and II of the RES by retiring RECs in the NEPOOL GIS, which closed its trading period for 2020 on June 15, 2021. 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, 2021 (with a revised report filed July 1, 2021). Table 1 provides an overview of 2020 RES compliance by Tier for each utility in the state.

[10] See Commission orders in Dockets 17-4632-INV, 19-0716-INV and 20-0644 for 2017, 2018, and 2019 compliance years.

Utility	2020 REC Retirements and Savings Claims as a Percentage of Sales		
	Tier I	Tier II	Tier III
Barton	59%	2.8%	5.70%
Burlington	103%	0%	12.23%
Enosburg Falls	59%	2.8%	5.70%
GMP	68%	3%	5.48%
Hardwick	59%	2.8%	5.70%
Hyde Park	59%	3%	2.67%
Jacksonville	59%	2.8%	5.70%
Johnson	59%	2.8%	5.70%
Ludlow	59%	2.8%	5.70%
Lyndonville	59%	2.8%	5.70%
Morrisville	59%	2.8%	5.70%
Northfield	59%	2.8%	5.70%
Orleans	59%	2.8%	5.70%
Stowe	59%	2.8%	2.76%
Swanton	100%	0%	5.70%
VEC	59%	2.8%	5.48%
WEC	100%	2.8%	4.35%
Vermont State Total	69%	2.61%	4.70%

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

In 2020, 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 2020, 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 2 illustrates REC retirements by resource for both Tier I and II.



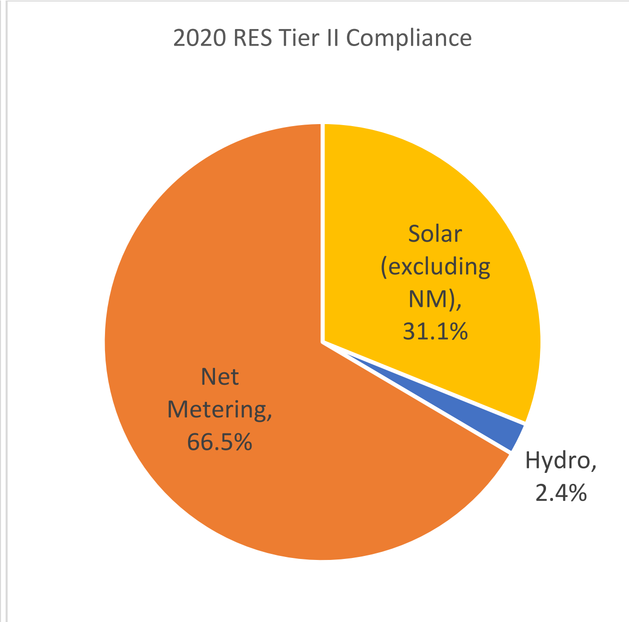


Figure 1. 2020 Tier I and Tier II REC retirements

Vermont utilities met their Tier III obligations with a variety of measures. Over 50 percent of Tier III savings 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 2020.

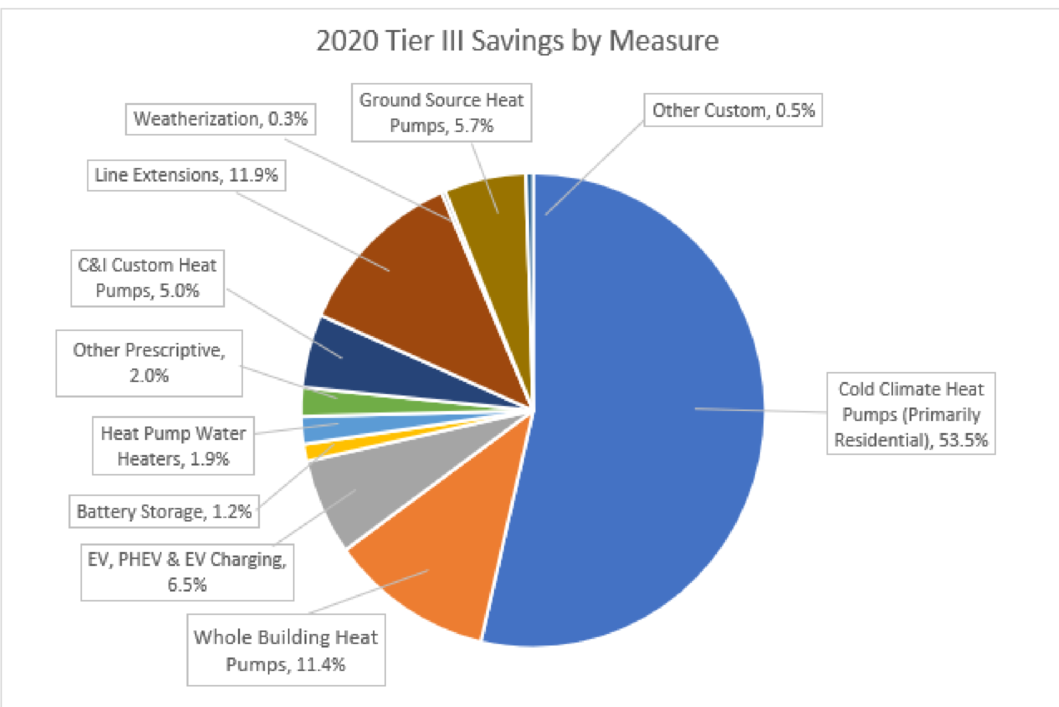


Figure 2. 2020 Tier III compliance measures

Table 2 summarizes key metrics on 2020 RES performance. Compliance costs for 2020 were estimated to be about $21 million, compared to maximum potential costs of $53.5 million.[11] Carbon Dioxide (CO2) emissions were reduced by approximately 620,567 tons from 2016 emissions.[12] This shift to more owned renewable attributes combined with an increased share from nuclear energy brings Vermont's average emissions rate down to 23.8 pounds of CO2 per MWh compared to the regional New England average of 633 pounds per MWh in 2019.[13]

2020 RES Performance			
	REC Retirements		*Compliance Cost*
Tier I	3,682,870	RECs	$2,320,000
Tier II	138,690	RECs	$6,010,000
Tier III	248,953	Mwhe	$12,640,000
Total Cost of Compliance			**$20,970,000**
Retail Sales	5,300,757	kWh	
Rate Impact of RES Compliance	2.3%		
CO2 Reduction from RES	620,567	tons of CO2	
Vermont Emissions Profile	23.8	lbs per MWh	

Table 2. 2020 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.[14] 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.

[11] Maximum potential costs reflect what the costs would have been if ACP was paid to meet all 2020 RES requirements.
[12] In addition to CO2 reductions directly resulting from RES, Vermont's electric mix was 26% nuclear in 2020 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.
[13] https://www.iso-ne.com/static-assets/documents/2021/03/2019_air_emissions_report.pdf
[14] The RES Model is available on the Department's website at: http://publicservice.vermont.gov/publications-resources/publications

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 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. 2021-2030 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. New in 2022, the Department also utilized the Social Cost of Carbon to estimate the value of avoided carbon emissions derived from the RES, a methodology consistent with recommendations of the Science and Data Subcommittee of the Vermont Climate Council[15]. Reduced GHG emissions reported are a result of Tiers I, II and III, and do not include other changes in Vermont's energy portfolio.[16]

4.1.2 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 under – 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 [17]. 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.

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

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[15] The report and recommendations prepared by the VCC technical consultants, EFG can be accessed here: SCC and Cost of Carbon Report revised.pdf

[16] From 2017 to 2018, Vermont's share of energy from nuclear generators increased from 13.5% to 30%, resulting in a significant decrease in GHG emissions. These reduced emissions are not included in the reported GHG emission reductions in this report.

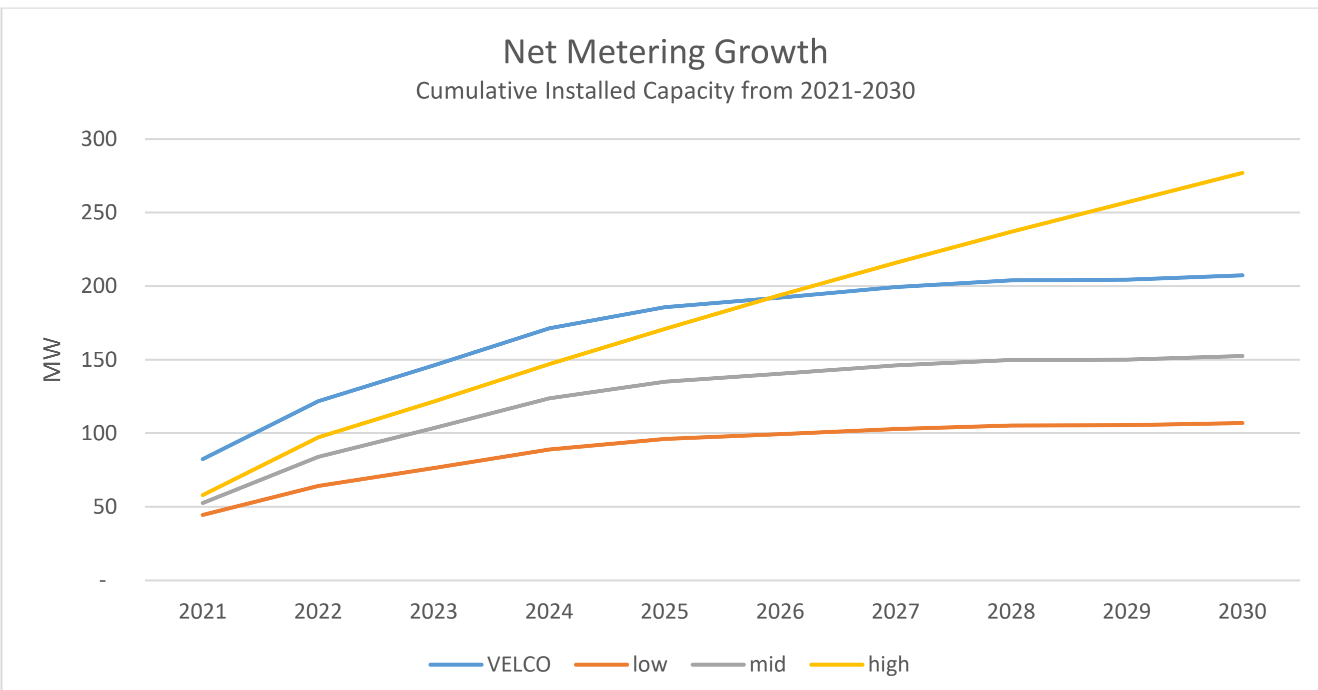
[17] The LRTP can be found at: 2021 LRTP to PUC_FINAL.pdf. Further information can be found at: https://www.velco.com/our-work/planning/long-range-plan.

Central Mitigation Pathway developed to support the Climate Action Plan (CAP)[18]. 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.

Both the baseline and high load forecasts are adjusted for expected net-metering growth, utilizing the same forecasts, which are discussed in detail next.

4.1.2.1 Net Metering Forecast

To forecast net-metering installations, the VELCO LRTP forecast was built upon a customer payback model. This results in high net metering deployment rates in the near-term that slow in the long-term as the market becomes saturated and net-metering compensation is reduced. The Department considers this forecast to be a reasonable base case, but likely high in the near term given the recent reduction in compensation resulting from the net-metering biennial review. The Department utilizes the VELCO forecast as the base scenario (or "mid" scenario as described in the model) with an adjustment downward to reflect actual net-metering deployment data. In addition, the model includes alternative scenarios to reflect higher and lower net-metering deployment. In the ongoing net-metering rulemaking[19] and 2022 Comprehensive Energy Plan, the Department has proposed adjusting the net-metering compensation structure, better aligning the compensation with the time and locational value it provides and the system installation costs, as well as to minimize the program's cross-subsidy from non-participating customers. If the compensation rates are adjusted downward, the pace of net-metering deployment will likely decrease, making the low net-metering scenario the most probable.



[18] 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
[19] See Case No. 19-0855-RULE for additional details.

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.

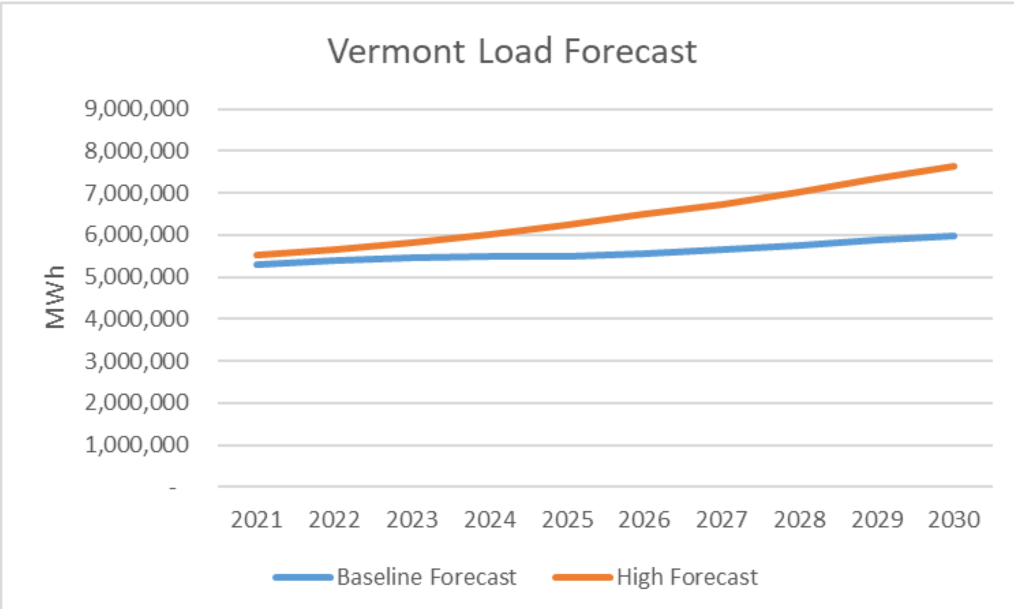


Figure 4. Baseline and high load forecast, 2021-2030

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.

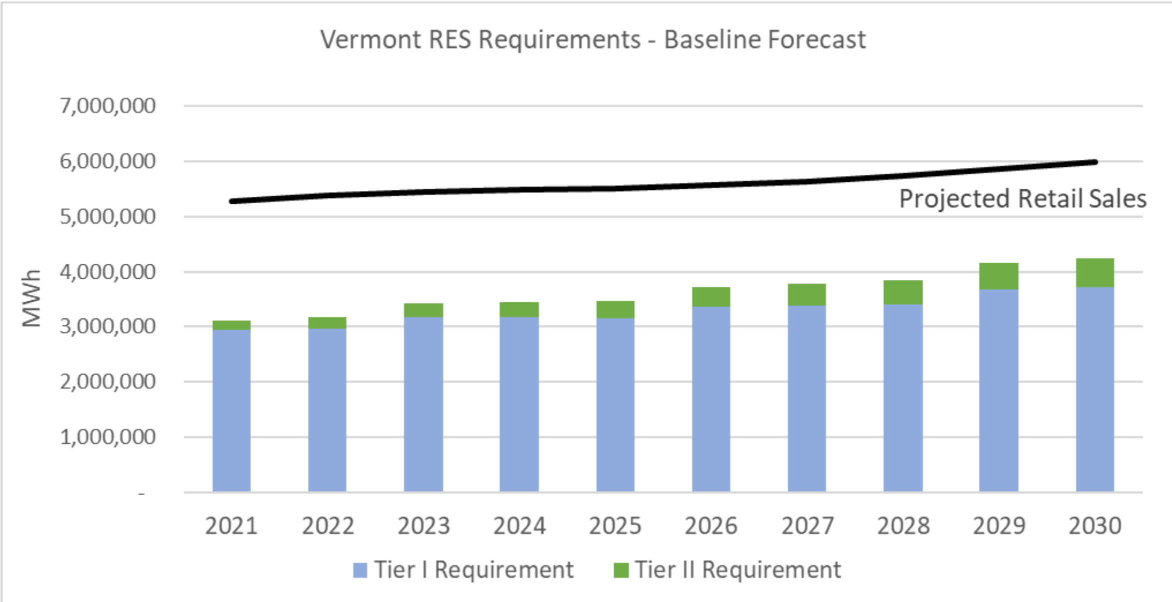


Figure 5. Projected retail sales and RES requirements under the baseline load forecast

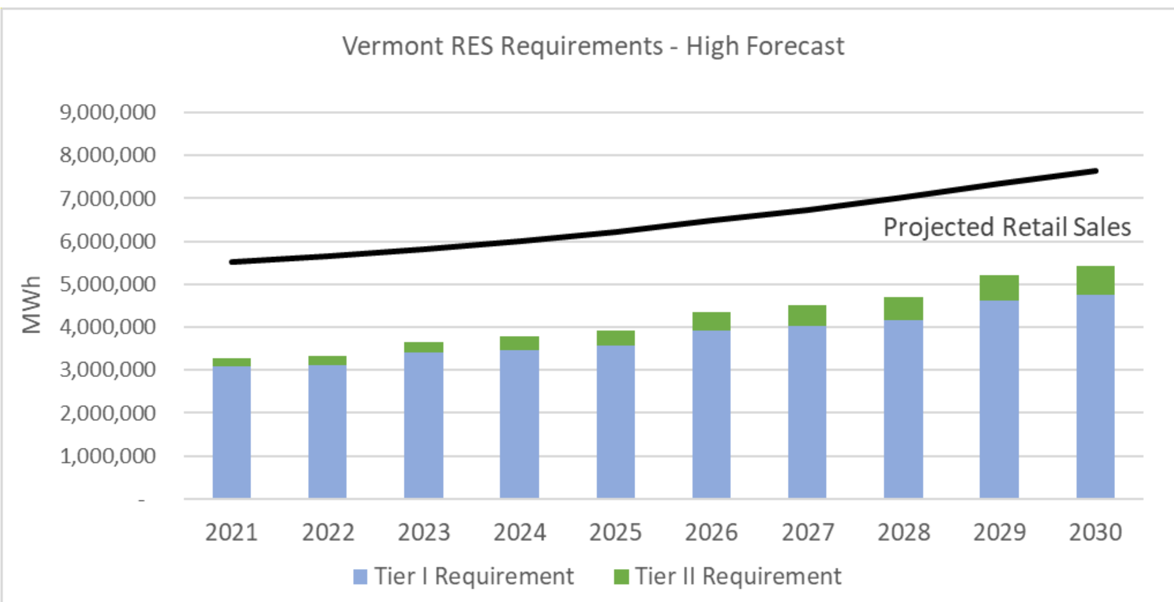


Figure 6. Projected retail sales and RES requirements under the high load forecast

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, PSD 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 understand 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 $10.58/REC and Tiers II and III were $63.48/REC in 2020; 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 stems from state policy. In recent years, the 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 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[20] and Massachusetts[21] 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

[20] State of New York Public Service Commission, Case 15-E-0302 Order Adopting Modifications to the Clean Energy Standard, Oct. 15, 2020. https://www.nyserda.ny.gov/-/media/Files/Programs/Clean-EnergyStandard/2020/October-15-Order-Adopting-Modifications-to-the-Clean-Energy-Standard.pdf.

[21] Massachusetts Department of Environmental Protection 310 CMR 7.75: Clean Energy Standard (CES) Frequently Asked Questions (FAQ) Version 2.0 (August 2021), available from: frequently-asked-questions-massdep-clean-energy-standard/download

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 recent years, prices have risen to $4-$5/REC and higher 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 $6.40/REC over the 10-year period, with prices starting at $5.00/REC in 2021 and escalating to $9.50/REC in 2030. The low case starts much lower, at $1.20/REC in 2021 and increasing to about $6.20/REC in 2030 (this was previously the “base” forecast in the 2021 RES Modeling effort) and the high case averages about $8.40/REC over the period, beginning at $6.00/REC and escalating to $11.00/REC.

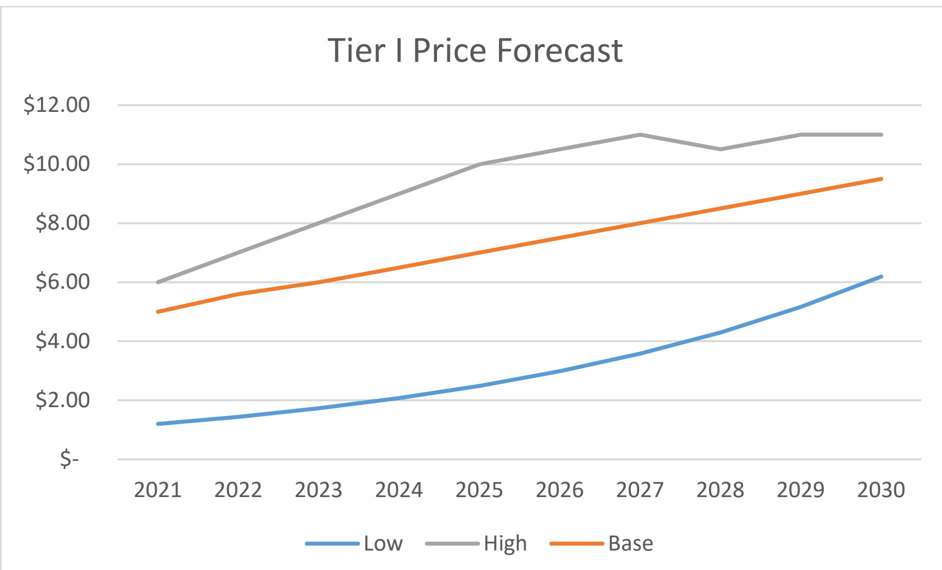


Figure 7. Tier I price forecasts

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, which remains similar to that used in 2020. The Tier II base-case assumes an average prices of about $33/REC. The low-case averages $18/REC, and the high-case averages $36/REC for 10 years.

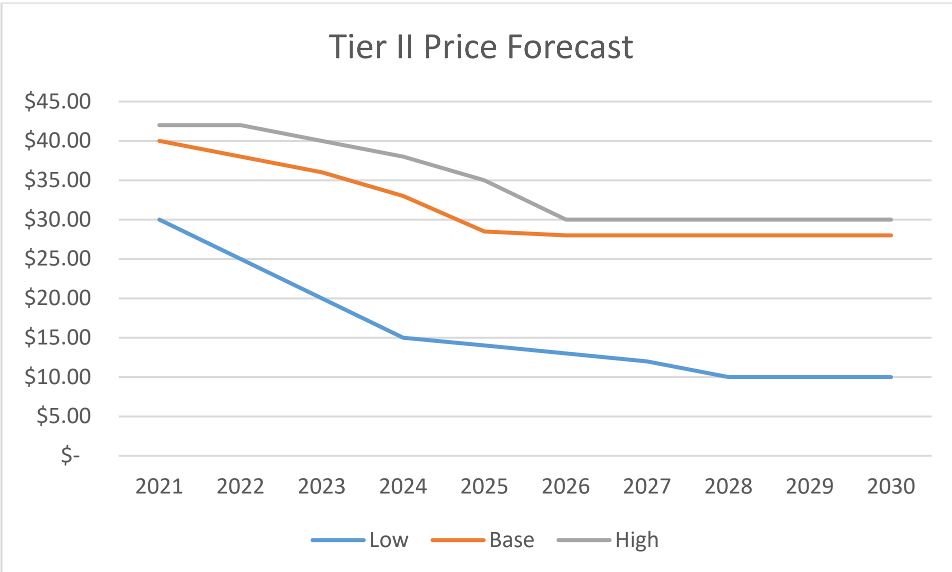


Figure 8 Tier II price forecast

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) 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.

[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.

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 four 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, but also 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 2018 the REC adjustor differential decreased to \$50 per MWh, and in July 2019 it decreased another \$10 per MWh 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[123]	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 – 8/30/2021	\$0.164	\$0.00	-\$0.04	\$0.00	\$0.00	-\$0.03	-\$0.04	\$0.00
NM 2.4	9/1/2021 –	\$0.164	\$0.00	-\$0.04	-\$0.01	-\$0.01	-\$0.04	-\$0.05	\$0.00

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 $40/REC so DUs are acquiring net-metered RECs at roughly the same price. This has not often been the case over the last several years. 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.

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 will likely 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. In contrast, if utilities exclusively incentivized non-electric Tier III measures, like biofuel burning equipment or weatherization upgrades, there would be no additional load or costs, and the Tier III costs would not be offset by higher retail sales.

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	40%
Electric Vehicles and Charging Stations	40%
Weatherization	5%
Custom	10%
Tier II RECs	5%

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 example has been informed over the previous several years by utilities' Tier III plans, Efficiency Vermont's Demand Resource Plan, and discussions with the utilities.

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

[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.

pathways, strategies, or actions, 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 compliance year, a large percentage of savings were derived from the installation of cold climate heat pumps. 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 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 2030, prices will be 55% 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 scenarios 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 50% 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 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 2021, 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 will lead 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.

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

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

[29] Actual 2020 overhead costs were reported to be $1,350,376. See Case No. 21-1045-INV for 2020 RES compliance filings made by utilities.

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 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, and 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.

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 "most likely" 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).

4.2.1 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[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 3,900,000 mmBtu lower in 2030 attributable Tier III, a reduction of 3% 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 17,000,000 mmBtu in 2030, a reduction of 13.5% 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 2030 would be around 4,600,000 mmBtu and that consumption of fossil-fuel based electricity in the Vermont mix would have been reduced by nearly 22,000,000 mmBtu, reductions of roughly 4% and 17% compared to total 2016 levels,

[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.

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 26% in 2020; while that share could decrease with contract expirations, the Department has assumed that 26% 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 2030, on an annual basis, Vermont will consume around 17% less fossil-based energy than it does today in the baseline load forecast scenario, or approximately 21% less in the high forecast scenario, as a direct result of RES, with an additional 5% reduction resulting from the increased share of nuclear. Similarly, annual carbon dioxide emissions could be reduced by nearly 990,000 tons (baseline load forecast) or 1,230,000 tons (high load forecast scenario) in 2030 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[33]), with approximately an additional 260,000 tons or 310,000 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 $135 million (baseline load forecast) or $169 million (high load forecast) of annual benefit in 2030, calculated based on the difference between the amount of electricity attributed to the residual mix in 2016 and 2020. On a cumulative basis, over the period of 2021-2030, under the most likely cost scenario, the Department estimates the RES could lead to over 7,000,000 or 8,000,000 tons of CO_2 saved in the baseline and high load forecast scenarios, respectively. This has a net-present value (NPV) of $649 million or $743 million based on the Social Cost of Carbon. Figure 9 illustrates annual estimated carbon reductions for 2021 to 2030 under each of the load forecast scenarios.

[33] 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

[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.

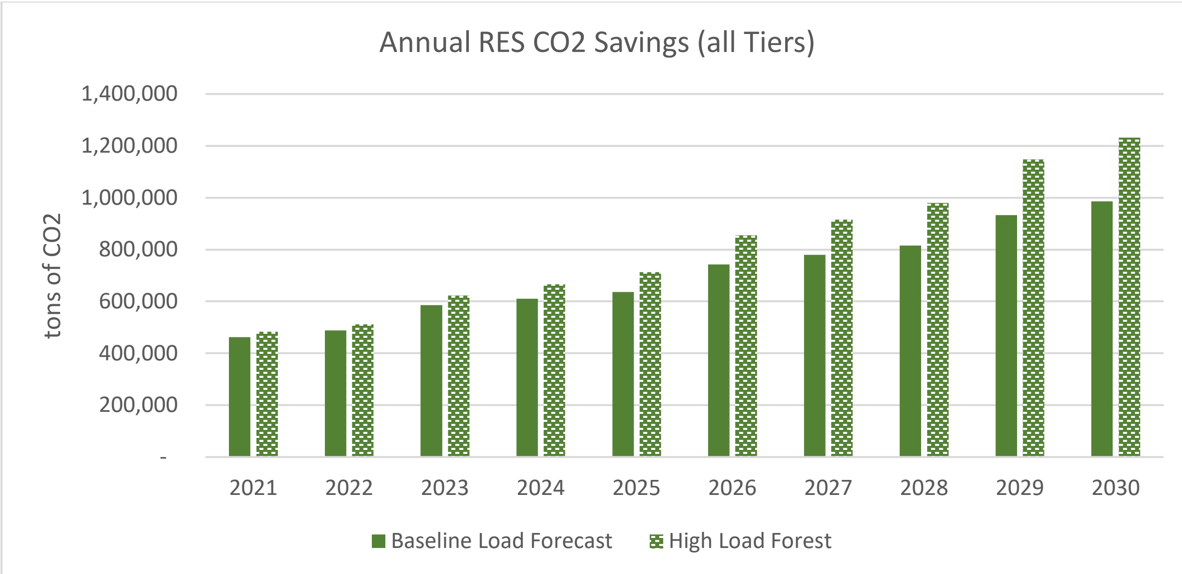


Figure 9. Annual CO2 savings due to the RES from all Tiers, 2021-2030.

4.2.2 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 (2021-2030) under the baseline and high load forecast scenarios. Under the baseline load forecast scenario, costs could be as low as $90 million or as high as $258 million (NPV). Under the high forecast scenario projected to meet GWSA requirements, these costs estimates increase to $106 million and $317 million, respectively (NPV). These range of costs, for each load forecast scenario, are illustrated in Figure 10, with the baseline forecast scenario results presented in solid bars and the high forecast results in the patterned bars. Based on analysis of the modeling results, the high load forecast scenario generally increases the expected cost of the RES, particularly under the high-cost scenario.

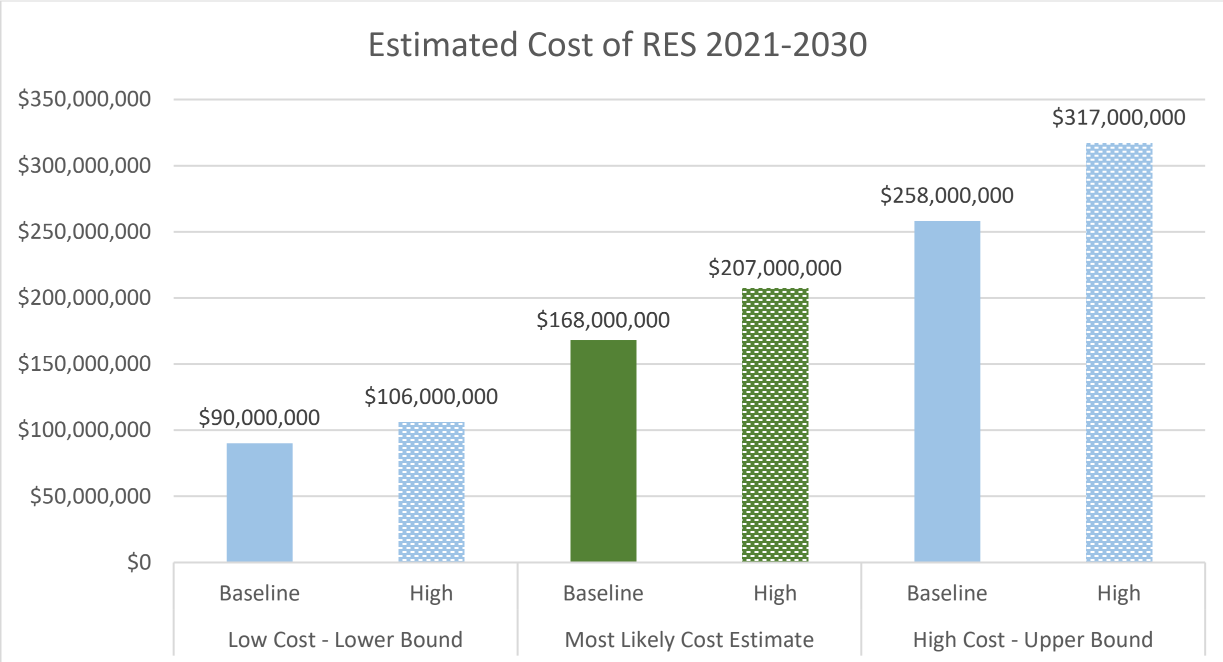


Figure 10. Estimated cost of the RES under the baseline and high forecast load sensitivities, 2021-2030

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 Forecast	LOW		HIGH	
NM Adoption Rate	LOW		HIGH	
Peak contribution of New Load	10%		75%	
Fossil Fuel Price	HIGH		LOW	
Load Forecast Scenario	Baseline	High	Baseline	High
Tier 1 Cost	**$43,000,000**	**$56,000,000**	**$126,000,000**	**$161,000,000**
Tier 2 Cost	**$91,000,000**	**$95,000,000**	**$103,000,000**	**$116,000,000**
+Tier 3 Cost	*$132,000,000*	*$149,000,000*	*$203,000,000*	*$232,000,000*
-Tier 3 Additional Revenue	*-$176,000,000*	*-$194,000,000*	*-$174,000,000*	*-$192,000,000*
Tier 3 Net Cost	**-$44,000,000**	**-$45,000,000**	**$29,000,000**	**$40,000,000**
TOTAL Cost of RES	**$90,000,000**	**$106,000,000**	**$258,000,000**	**$317,000,000**
Rate Impact	0.84%	0.87%	4.77%	5.37%

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

As with the 2021 modeling effort, in 2022 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 approximately $99 million based on the "most likely" (or mid cost range) assumptions, with a potential range of costs between $43 million (NPV) and $126 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 $126 million ("most likely"), $56 million (lower bound), and $161 million (high bound), respectively. Tier I costs drive the majority of the total cost increases between the baseline and high load forecast scenario, accounting for roughly 80% of the total cost increase in the low cost scenario and over 50% percent of the cost increase under the high cost scenario. 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 Tier I RECs, which currently has uncertain implications for prices. This would also be influenced by any redesign of the RES to support achieving GWSA greenhouse gas emissions reductions and 2022 Comprehensive Energy Plan goals, as discussed in both the initial Climate Action Plan[35] and forthcoming 2022 Comprehensive Energy Plan.

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

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

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 adding at all to peaks, it is conceivable that utility compliance with the RES would exert no net upward 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 2.6% (baseline load forecast scenario) to 2.9% (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 all new Tier III loads come online as flexible demand-side resources that do not add to existing levels of peak demand. To illustrate this point, a heat pump or electric vehicle that draws large amounts of power from the grid during peak times might cost the utilities as much as several hundred dollars per MWh consumed by the equipment. This is significantly more than the current retail rate of roughly $164 per MWh (and would thus contribute to upward rate pressure). This does not account for the fact that increases in peak could also result in increased distribution and subtransmission costs required to serve increased load. If those same technologies can avoid loading the grid at peak times though, it might only cost utilities $30 to $50 per MWh consumed by the equipment.

5. RES Compliance and Recommended Changes

As previously discussed, on November 23rd, 2021, the PUC has issued an order in Case No 21-1045-INV on 2020 RES compliance, approving compliance for the 2020 compliance year.

At this time, the Department does not recommend any specific statutory changes related to the RES. However, consistent with the forthcoming 2022 Comprehensive Energy Plan, the Department recommends consideration of design options for a carbon-free or 100% renewable energy standard to support achieving GWSA greenhouse gas reduction requirements. Specifically, the Department recommends considering adjustments to the existing RES through a transparent and open process, like a PUC proceeding. Such a proceeding should consider how a future RES could better reflect the time and locational values of electric resources in Vermont and development of a cohesive set of programs to support the future RES, such as modifications of the net-metering program to reduce program costs and better align with value these resources provide. This is consistent with recommendations included in the initial Climate Action Plan.

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, the Department made the RES model and all relevant assumptions public on its website and sought public comments on it. The Department specifically requested input on modeling assumptions related to Tier III measure allocations and incentive levels, the appropriate net-metering forecast to use, and Tier I and Tier II price forecasts. Comments were received from Green Mountain Power (GMP), Vermont Electric Cooperative (VEC), Washington Electric Cooperative (WEC), Vermont Public Power Supply Authority (VPPSA), Stowe Electric Department (SED), Energy Action Network (EAN), Renewable Energy Vermont (REV), the National Biodiesel Board (NBB), and the Vermont Fuel Dealers Association (VFDA).

Many of the utilities who responded (WEC, VEC, GMP, and VPPSA) specifically responded to the Department's questions regarding modeling parameters and forecasts. WEC highlighted that Tier III allocations and incentives will evolve over time while GMP noted that while the Tier III incentives in the model are high enough to meet RES obligations currently, they likely will not be high enough to meet GWSA requirements. They further noted that while the RES is currently functioning well, futures modifications or complementary policies will likely be needed to meet the GWSA. VPPSA further provided data to show how their Tier III measure allocations differ from the approximation included in the RES model. VPPSA further noted Tier III incentive levels seemed reasonable except for the Weatherization incentive. This question ultimately prompted the Department to update this variable in the model. Each of the utilities provided input on the net-metering and price forecasts in the model which suggest the range of forecasts included offer a reasonable assessment of the market.

Both GMP and EAN offered comments on the load forecast in the model. GMP highlighted the draft load forecast represented relatively low EV adoption rates, providing reference to their recent IRP forecasts which include EV and heat pump adoption curves to meet GWSA requirements. Similarly, EAN highlighted that the Department's draft load forecast was significantly lower than those developed by EAN and SEI in the course of modeling pathways to meet GWSA requirements. Given these considerations, the Department made two adjustments to the load forecast in the RES Model: the original load forecast was adjusted upwards to reflect more recent electrification data. In addition, the Department added a second load forecast scenario based on the Central Mitigation Pathway load forecast developed by SEI for the Climate Action Plan and Comprehensive Energy Plan modeling. These two forecasts now allow the model to estimate a broader range of potential future impacts of the RES.

In addition, the NBB and VFDA offered several comments regarding the treatment of renewable liquid and biomass fuels to meet Tier III obligations. The NBB observed that they support the concept of Tier III generally but the only obligated parties in RES Tier III are DUs and this has led to the unintended conversion of the Tier III program into an electrification-only incentive program. Along these lines, the Department's review of RES no longer gives recognition to renewable fuels. The Department notes that this is due to the observation that DUs have focused on electrification and while renewable fuels like biodiesel are eligible, the DUs have not yet chosen to use those as measures to reach their obligations, and the Department does not currently expect them to. Further, the NBB raises considerations about appropriate accounting for the emissions rate of different resources, highlighting the need to use the ISO New England Emissions rate and lifecycle greenhouse gas emissions analyses. These considerations are being discussed in the Science and Data Subcommittee in the Vermont Climate Council and the Department will continue to participate in those discussions.

REV also provided comments regarding the existing structure of the RES, include the resources currently allowed under the various Tiers, REC accounting of renewability currently employed by the New England region, and the need for development of new resources moving forward. REV made several recommendations for improving the

RES moving forward, including to eliminate the ability of Vermont's retail electric utilities to claim a green energy portfolio by purchasing nuclear carbon offsets, that the Department should consider phasing out the ability of distributed utilities to satisfy their Tier 1 requirements with the purchase of RECs from Hydro Quebec (HQ), a provision unique among New England state policies, and that all new energy purchases must adhere to the concept of "additionality" and be from new renewable energy sources. The Department agrees that these are all key policy issues that should be considered as Vermont evaluates moving to either a carbon-free or 100% renewable RES and that these issues should be discussed in the Comprehensive Energy Plan's proposed transparent proceeding. With regards to the use of HQ attributes to satisfy Tier I RES requirements, the Department notes that several states in the New York and New England region, including New York and Massachusetts (as discussed on page 14 of this report) do allow the use of large hydropower under their clean energy policies. The Department further highlights that removing large hydropower from the list of eligible resources would require a change to Vermont statute which is outside of the jurisdiction of the Department. With regards to additionality and emissions accounting, this has been a topic under discussion in the Vermont Climate Council with regards to the existing state greenhouse gas inventory methodology, and the Department will continue to participate in those discussions.

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	+2.3%	+2.3%	+2.3%
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	548 MW by 2030	424 MW by 2030	378 MW by 2030
Tier I REC Price	Avg $8.40 /MWh	Avg $6.41/MWh	Avg $2.60/MWh
Tier II REC Price	Avg $35.90 /MWh	Avg $32.85/ MWh	Avg $18.40/MWh
Energy Price Assumptions			
Fossil Fuel price scenario	Low	Mid	High
Fossil Fuel price trend	-1%/yr	1.6%/yr	+5.0%/yr